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Low-cost revamp strategies improve FCCU performance
New methods ease multiline stray-current measurement

OIL&GAS JOURNAL®

Sept. 24, 2007
Volume 105.36

APPLIED GEOPHYSICS

REGULAR FEATURES

COVER

The megamerge of almost 4,000 sq miles in 10 previously separate South Louisiana Gulf Coast 3D seismic surveys has provided Swift Energy Co., Houston, with a regionally uniform proprietary database in a premier US producing region. Drilling below 16,000 ft in the area is sparse. An article on p. 34 in OGJ's Applied Geophysics special report describes the company's exploration effort. Images courtesy of Swift Energy.

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Processing

Transportation

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General Interest — Quick Takes

Chavez vows to expand gas, oil production

Venezuelan President Hugo Chavez said his government is "launching the socialist gas revolution," claiming that Venezuela possesses "80% of South America's gas reserves" and "30% of the gas reserves in the Americas."

He said Sept. 16 that his administration would invest $18 billion to expand natural gas production to 11 bcfd from the current 7 bcfd over the next 5 years.

Touting his country's assets, Chavez said Venezuela has proved gas reserves of 150 tcf onshore and 30 tcf offshore.

Meanwhile, the Venezuelan leader said his government also plans to increase the country's production of crude oil to "5 million b/d in 2012," up from the current 3.2 million b/d.

"We'll take it there on pace with prices because for us it's more important to maintain the correct price of oil than to flood the market," said Chavez, who added that the world is entering an energy crisis because "oil is running out."

APEC: Growth requires diversified energy mix

Foreign and trade ministers at the Asia-Pacific Economic Cooperation Forum Sept. 6 called for ensuring a "diversified mix of energy sources," including nuclear energy, in order to pursue the region's long-term economic growth, while reducing dependence on fossil fuels.

In a joint statement issued after their recent 2-day meeting in Sydney, the ministers said the diversified mix includes "the use of natural gas, biofuels from sustainably farmed crops and residues, renewable energy, and nuclear energy for interested economies."

"We recognized the importance of achieving oil security, including through improving data sharing," they said. "Climate change, energy security, and clean development are of vital interest to APEC economies."

The ministers agreed on "the important role of market-based solutions in mobilizing economy-wide efforts to address energy security and achieve sustained reductions in greenhouse gas emissions."

APEC comprises Australia, Brunei, Canada, Chile, China, Hong Kong, Indonesia, Japan, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, the Philippines, Russia, Singapore, South Korea, Taiwan, Thailand, the US, and Vietnam.

ExxonMobil seeking arbitration for Cerro Negro

ExxonMobil Corp. has filed a request for arbitration over Venezuela's nationalization of the Cerro Negro heavy oil project.

The firm, which filed the arbitration request with the International Center for Settlement of Investment Disputes, held a 41.67% interest in the project before Venezuela expropriated it in June.

The appropriation resulted from a nationalization decree issued by Venezuela's President Hugo Chavez earlier this year.

Venezuela took majority control of the country's privately run oil projects on May 1 and gave the companies until June 26 to decide to accept new terms as junior partners.

ExxonMobil and ConocoPhillips rejected the offer, while Chevron Corp., BP PLC, Total SA, and Statoil ASA accepted.

Venezuela's tax authority Seniat recently said it had received or been promised payments from two state-dominated joint venture firms after imposing large back-tax bills on recently nationalized heavy oil development projects, including Cerro Negro (OGJ Online, Sept. 6, 2007).

Unions push safety look into Shell operations

The UK Health and Safety Executive should investigate Royal Dutch Shell PLC's safety operations in the North Sea because its change management process is affecting safety on the assets it plans to sell, charges UK trade unions Unite and the Oil Industry Liaison Committee.

Shell union employees complain that there is poor communication from the company regarding the sale of the Cormorant Alpha-Dunlin Alpha and the Tern, Eider, and North Cormorant installations. In a letter to senior managers, offshore staff said as a result of recent departures attributable to the prolonged nature of the divestment issue, "Many platforms areas are now not fully covered by trained and competent people, and certain HSE safety critical roles are not fully supported.

According to the unions, positions lacking adequate staff are control room operators, shift supervisors (process), instrumentation technical custodians and responsible persons (electrical), and reportedly a lack of suitably trained Fire Team Leaders.

The unions said that as key personnel have left in protest at treatment they received, gaps appeared in critical safety positions, which could leave those left behind unable to cope in emergency situations. The unions want to know if Shell can comply with the safety elements of PFEER (prevention of fire and explosion, and emergency response) Regulations 1995 for offshore installations.

Shell staff members also are unhappy that the company has discontinued its "preferred HR principals for divestment and acquisition" system that it has used for 8 years when selling other assets. ✦

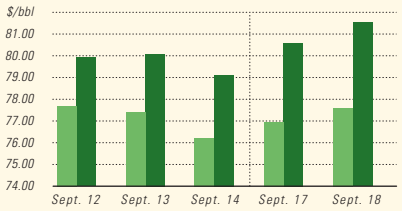
Exploration & Development — Quick Takes

Libya prequalifies 56 firms in license round

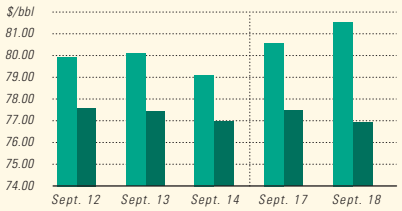
Libya's state-owned National Oil Co. has prequalified 35 operators and 21 investors out of the 70 firms or more that were said to have applied in its current natural gas licensing round.

Industry Scoreboard

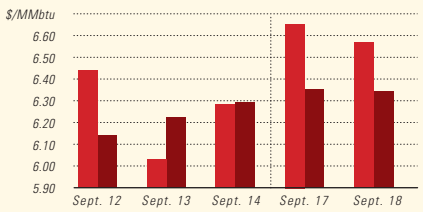
IPE BRENT / NYMEX LIGHT SWEET CRUDE



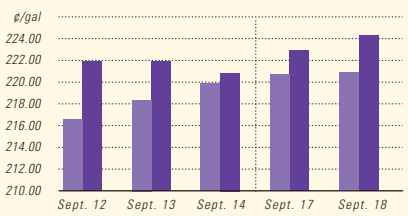
WTI CUSHING / BRENT SPOT



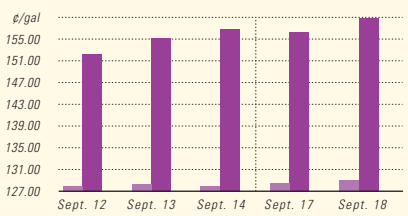
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



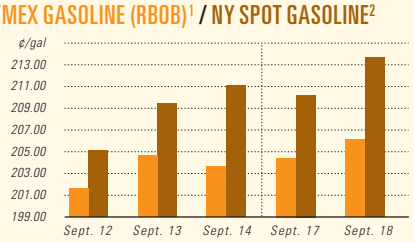
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending,
[2]Nonoxygenated regular unleaded.

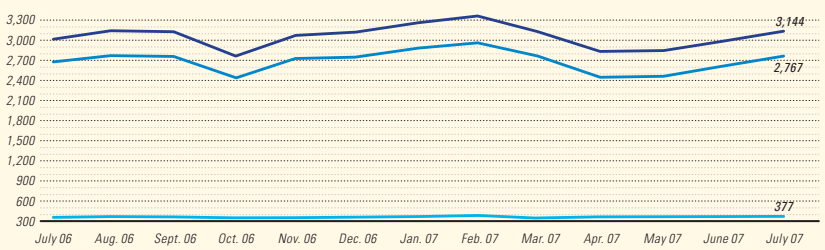
US INDUSTRY SCOREBOARD — 9/24

Latest week 9/7	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	9,590	9,507	0.9	9,323	9,223	1.1
Distillate	4,192	4,194	—	4,228	4,150	1.9
Jet fuel	1,630	1,631	–0.1	1,623	1,620	0.2
Residual	792	711	11.4	767	716	7.1
Other products	4,905	5,097	–3.8	4,855	4,864	–0.2
TOTAL DEMAND	21,109	21,140	–0.1	20,796	20,569	1.1
Supply, 1,000 b/d						
Crude production	5,108	5,162	–1.0	5,178	5,105	1.4
NGL production[2]	2,392	2,261	5.8	2,365	2,194	7.8
Crude imports	10,109	10,573	–4.4	10,049	10,118	–0.7
Product imports	3,310	3,989	–17.0	3,523	3,638	–3.2
Other supply[3]	1,031	1,190	–13.4	994	1,138	–12.7
TOTAL SUPPLY	21,950	23,175	–5.3	22,109	22,193	–0.4
Refining, 1,000 b/d						
Crude runs to stills	15,665	15,780	–0.7	15,276	15,278	—
Input to crude stills	15,900	16,205	–1.9	15,528	15,643	–0.7
% utilization	91.1	93.2	—	89.1	90.0	—

Latest week 9/7	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	322,649	329,660	–7,011	327,724	–5,075	–1.5
Motor gasoline	190,417	191,083	–666	206,994	–16,577	–8.0
Distillate	133,963	132,170	1,793	144,588	–10,625	–7.3
Jet fuel-kerosine	41,533	41,186	347	40,931	602	1.5
Residual	36,793	36,375	418	42,766	–5,973	–14.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	20.6	21.0	–1.9	20.6	—	
Motor gasoline	19.9	19.8	0.5	21.7	–8.3	
Distillate	32.0	31.4	1.9	34.9	–8.3	
Propane	57.4	55.4	3.6	58.6	–2.0	
Futures prices[5] 9/14	Change,		Change		Change	%
Light sweet crude, $/bbl	79.33	75.95	3.38	63.57	15.76	24.8
Natural gas, $/MMbtu	6.11	5.65	0.47	5.31	0.80	15.1

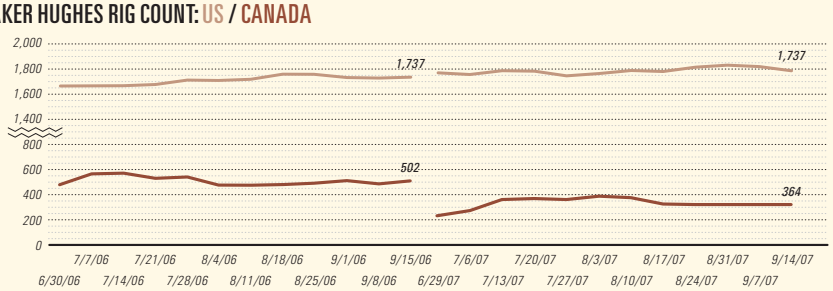
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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NOC launched the round on July 8 to award foreign energy companies gas exploration licenses for 41 blocks, with offers to be submitted by Aug. 22 and successful bidders to be announced on Dec. 9.

NOC expected to award about 12 natural gas exploration contracts for the 41 blocks, which cover a total area of 72,500 sq km.

Libya's gas reserves are estimated at 1.314 trillion cu m and its proved oil reserves are 36 billion bbl, according to the Organization of Petroleum Exporting Countries.

In May, Libya signed a $900 million exploration deal with BP, under which BP will explore an area of some 54,000 sq km, primarily for gas, but also in the hope of finding oil.

Centurion Petroleum finds oil in southern Egypt

Centurion Petroleum Corp. has discovered oil in southern Egypt with the Baraka-1 exploration well, the company reported on Sept. 4. Testing of the Early Cretaceous Abu Ballas formation produced 150 b/d of oil from a 39 ft perforated interval.

The recovered oil was 37° gravity, with a wax content similar to the crude oil currently produced and exported in large quantities in Sudan. The well, which was drilled in the Komombo Concession in Upper Egypt, reached a TD of 8,712 ft and penetrated several oil-bearing zones. Baraka tested different volumes of oil from three additional intervals in the deeper early Cretaceous section. The company is calculating the size of the reserves and potential productivity.

The find could affect the economic development of Upper Egypt, which is outside of the country's traditional producing areas. Dana Gas, the parent of Centurion Petroleum, plans to bring the oil on production as early as possible using existing transportation and refining facilities. It also will continue an aggressive exploration and appraisal program in the area.

The Komombo concession is 700 km from Cairo and 320 km from the closest refinery at Assiut. Early oil production from this discovery may be transported by rail or Nile river barges to the Assiut refinery to the north, Dana Gas added.

Venture tests gas from North Sea field

Venture Production PLC has tested gas production from the first well on Chiswick field in the UK southern North Sea. The company carried out a multiple fracture well stimulation, and 50 MMcfd of gas was produced through a restricted $^{72}/_{64}$-in. choke.

Chiswick has been tied back to the Venture-operated Markham J6A platform. The reservoir quality and well production performance are "in line with expectations," Venture said. The well is expected to reach gross production rates of 55-60 MMcfd through the platform facilities following completion of the ongoing clean-up program, the company said.

Commercial gas production is expected to start at the end of September after the current Markham field annual shutdown is finished.

The Noble Kolskya jack up drilled the Chiswick Alpha well (49/4a-C1y) for Venture during the first half of this year. During August it carried out five hydraulic fracture procedures to maximize gas deliverability from the field.

Venture plans to drill a second development well, Chiswick Gamma, using the same rig. It also is considering drilling another three wells on the field to target incremental reserves on the Gamma block and the undrilled Beta block, depending on performance from the first two wells.

Norsk Hydro takes 10% equity in ONGC's KG block

Norway's Norsk Hydro AS has taken a 10% participating farm-in stake in Oil & Natural Gas Corp.'s KG-DWN-98/2 deepwater block in the Krishna-Godavari basin off eastern India.

Hydro may increase the stake by another 10% after commerciality is shown.

The agreement is the follow-up of a development and cooperation agreement the companies signed in July in which an investment cap of $26 million was established during the appraisal phase.

Hydro also is working with ONGC for thin-oil-ream exploitation in Vasai East, near Mumbai—one area identified in the earlier agreement.

In addition, the Norwegian firm has expressed interest in assuming a participating interest in additional New Exploration Licensing Policy (NELP) blocks as well. ONGC has 32 offshore blocks under NELP, of which 12 are in ultradeep water, 14 are in deep water, and 6 in shallow water. ONGC has 100% participating interest in 12 blocks, while varying levels of equity in the remaining 14 blocks have been farmed out to others. ✦

Drilling & Production — *Quick Takes*

Hydro begins Ormen Lange gas production

Development operator Norsk Hydro AS has started natural gas production from giant Ormen Lange field on the Norwegian continental shelf, with deliveries via the Langeled pipeline. Ormen Lange will meet as much as 20% of the UK's gas needs.

The field, expected to supply 70 million cu m/day of gas and 50,000 b/d of condensate at peak rate, will position Norway as the world's second-largest gas exporter after Russia.

Hydro is testing production from the field in the North Sea about 120 km from the Norwegian coastline, until the inaugural ceremony on Oct. 6, so gas flows may vary.

From a depth of 800-1,100 m, the gas is transported by pipeline through demanding subsea terrain to Nyhamna on the island of Gossen in the municipality of Aukra in More and Romsdal. After being processed, the gas will be sent through the 1,200 km Langeled subsea pipeline to Easington on England's east coast.

Norway currently is the world's third largest gas exporter, delivering 85 billion cu m/year. When Ormen Lange reaches plateau production in 2010, total gas exports from Norway will increase to 120 billion cu m/year, or 20% of Europe's gas requirements.

Royal Dutch Shell PLC will assume operatorship from Hydro on Dec. 1.

CNPC increases drilling forecast for 2007

China National Petroleum Corp. (CNPC) has announced plans to drill 17% more horizontal wells in 2007 than originally planned in order to increase production from both mature and newer fields.

CNPC said it completed drilling 610 horizontal wells by the end of August, exceeding its original full-year target of 600. The state-run firm said it was encouraged to step up the number of horizontal wells to 700 this year because of recent success at Sichuan.

It said that last month's output from a horizontal well in a Sichuan field was 20 times greater than that of a neighboring vertical well. In 2006, the company drilled 522 horizontal wells, equal to the total number it drilled in 2000-05.

Petrobras commissions Piranema FPSO unit

Brazilian President Luiz Inacio Lula da Silva officially launched the Piranema floating production, storage, and offloading unit, chartered from Sevan Marine and anchored off the Sergipe coast.

The unit's hull was built at the Yantai-Raffles shipyard in China and then transported to the Keppel Verolme shipyard in the Netherlands, where the oil and gas production processing plant was installed.

The unit, which is capable of producing as much as 30,000 b/d of oil and storing 300,000 bbl of oil, is the world's first circular FPSO unit and will interconnect a total of six wells at maximum depths of 1,450 m.

Recently Sevan said Petroleo Brasileiro SA (Petrobras) revised the schedule of start up of oil production from Piranema field because of normal delays in the completion of operations. Petrobras signed the charter agreement with Sevan in February 2004.

Declared commercial in August 2004, Piranema field is in deep waters, 35 km off Aracaju, the capital of Sergipe state, and will produce 44° gravity oil.

Petrobras taps Technip for subsea work off Brazil

Petroleo Brasileiro SA (Petrobras) has awarded three contracts totaling $270 million to France's Technip for pipeline work in deepwater developments off Brazil.

The first contract covers engineering, procurement, installation, and commissioning of a rigid flowline that will connect Canapu oil and gas field in 1,700 m of water in the Espirito Santos basin to the Ciadade de Victoria floating production, storage, and offloading vessel anchored in 1,400 m of water. This 21-km flowline will be the first application of pipe-in-pipe (PIP) technology for subsea gas transportation in Brazil. Technip's Deep Blue deepwater pipelay vessel will install the flowline during fourth quarter 2008.

Intec Engineering earlier this year completed the front-end engineering design for the PIP flowline (OGJ Online, Apr. 4, 2007).

The second contract comprises engineering and procurement of 37 km of 4-in. and 6-in. flexible flowlines for Mexilhao gas field in the Santos basin. The reservoirs in Mexilhao have high pressures and temperatures. The 6-in. flowlines have been specially designed to cope with extreme temperature and pressure of the carried fluids.

The third contract includes engineering and procurement of four large-diameter flexible risers for the Campos basin oil outflow and treatment plan (PDET) that will be installed in 1,300 m of water in the Campos basin. The PDET export system is designed to increase oil production in Campos basin by as much as 630,000 b/d (OGJ Online, Oct. 20, 2005).

EDC lets contract for jack up construction

Egyptian Drilling Co. (EDC) has let a contract to SembCorp Marine subsidiary PPL Shipyard to build a $201 million Baker Marine Pacific Class 375 (BMC Pacific 375) jack up.

Construction is expected to start in the third quarter with delivery slated for December 2009.

The rig will be built based on PPL's proprietary BMC Pacific 375 Deep Drilling design and will be equipped with a drilling package capable of drilling high-pressure, high-temperature wells to 30,000 ft total depth, while operating in as much as 375 ft of water.

EDC is an equal joint venture of Egyptian General Petroleum Corp. and AP Moller-Maersk Group. ✦

Processing — *Quick Takes*

Sinclair Tulsa plans refinery expansion

Sinclair Tulsa Refining Co. plans a major expansion of its 70,000 b/d Tulsa refinery. The company said recent changes in federal and state tax law have been an encouraging factor in its decision.

The expansion project is expected to increase the facility's output of ultralow-sulfur gasoline and diesel. A net reduction in actual refinery emissions, also could be realized after the expansion is completed, Sinclair said.

Three major components are involved in the project. These include the facility's refining capacity, which will be increased by 45,000 b/d to 115,000 b/d; a new delayed coker unit, which will be added to increase refinery output of gasoline and diesel; and modifications to the plant to enable processing of a wider range of oil, including heavy, sour crude.

The delayed coker unit will use odor and particulate control technology that has been successfully demonstrated in California.

Sinclair recently applied to the Oklahoma Department of Environmental Quality for an air quality construction permit for the expansion project. The application indicates the expansion will be below the Prevention of Significant Deterioration significance thresholds for all criteria pollutants.

Assuming ODEQ approves the permit, construction work could begin in 2008, with project completion expected in 2011.

Sinclair also plans to install a flare gas recovery system to minimize flaring.

In addition, the company proposes to treat refinery wastewater to an acceptable level for discharging into Tulsa's treatment system.

Saras to revamp Sarroch refinery visbreaker unit

Saras SPA has completed a process license agreement with an

affiliate of Shell Global Solutions International BV to revamp the visbreaker unit at the 300,000 b/cd Sarroch refinery in Sardinia, Italy.

The unit will be upgraded to use Shell GSI's deep thermal conversion technology, which will allow the refinery to process heavier crudes.

Saras and Shell GSI are working alongside ABB Lummus Global, one of Shell's authorized licensors, and have scheduled delivery of the project by the end of September.

The visbreaker license agreement follows the revamp of the refinery's hydrocracker in March.

The Sarroch refinery has recently undergone a maintenance cycle involving shutdown of a crude distillation unit, a vacuum unit, and now the visbreaking unit. As a result, refinery runs have been reduced by about 10% from normal levels, Saras said.

Spanish firms dropped from Gassi Touil project

Sonatrach has taken sole control of the Gassi Touil integrated gas project in eastern Algeria and dismissed Repsol YPF SA and Gas Natural SDG SA from the project development.

Sonatrach terminated the contract after months of political struggle between Algiers and Madrid over control. Media reports said Sonatrach blamed the companies for cost overruns and delays.

Repsol YPF and Gas Natural plan to launch international arbitral proceedings against Sonatrach, protesting that the project had been taken "through illegitimate means." They will seek damages and determination of whether the contract had been rightfully terminated.

This was the first project in Algeria to be awarded to a foreign consortium. However, to exert greater control over its national resources, Algeria within the past 18 months passed a law requiring Sonatrach to maintain a 51% stake in energy projects.

Sonatrach's decision leaves the Spanish companies without access to huge reserves and supply contracts after they beat stiff competition to win the lucrative tender in 2004. For Repsol in particular, the effect is galling, as the company was also forced to revise downwards its oil and gas reserves in South America partly due to energy nationalizations in Bolivia and Venezuela.

The $7 billion Gassi Touil project involved exploration and production phases as well as construction of a 4 million-tonne/year gas liquefaction plant and marketing activities by 2009. Repsol YPF held a 48% stake, Gas Natural 32%, and Sonatrach 20%. ✦

Transportation — *Quick Takes*

Pemex brings gas line back in service

Mexico's Petroleos Mexicanos (Pemex) resumed natural gas transportation Sept. 17 through its 48-in. Cactus-San Fernando pipeline.

The firm said it expected to have service completely restored by Sept. 18 on the network that was put off line by guerrilla bombs at Delicias, Rio Actopan, and Rio La Antigua.

Pemex said the attacks did not result in any casualties, but it cut power to more than 2,000 businesses in 10 states, according to figures from the Canacintra industrial association. The shutdown cost those firms about $100 million/day, Canacintra reported.

The Ejercito Popular Revolucionario (EPR), a secretive Marxist group that killed dozens of Mexican police and soldiers in the late 1990s, claimed responsibility for the attacks.

EPR said it bombed the pipeline to force the release of EPR militants it alleges were arrested by the government May 25. Mexican officials say the rebels are not in custody.

EPR says Edmundo Reyes Amaya, Raymundo Rivera Bravo, and Gabriel Alberto Cruz Sanchez have not been seen since their arrest. EPR wants them back and apparently has been bombing the country's oil and gas pipelines for that purpose.

In the latest attacks, one bomb was discovered intact, with a note attached. "Alive you took them, alive we want them back," in an apparent reference to the missing EPR militants.

The rebel group has warned of more attacks if its missing members are not returned unharmed.

Nakilat to take delivery of four LNG carriers

Nakilat, the joint venture of Overseas Shipholding Group Inc. and Qatar Gas Transport Co., will soon take delivery of four new-generation, Q-Flex LNG carriers.

The first two carriers—the Al Gattara built by Hyundai Heavy Industries Co. Ltd. and the Tembek built by Samsung Heavy Industries in Geoje Island, South Korea—are scheduled to be delivered at the end of October.

Deliveries for the remaining vessels are expected in early 2008.

The Q-Flex LNG carriers can transport 216,000 cu m of LNG each, about 40% more than the standard LNG vessels currently in service. They are equipped with an onboard reliquefaction plant.

In addition, the vessels have lower energy requirements than conventional LNG vessels due to economies of scale created by their size and the efficiency of low-emission, electronically controlled diesel engines. Safety features include dual propellers and rudders.

Nakilat last year added six Q-Max LNG carriers to its fleet, which is expected to comprise 61 carriers by 2010 (OGJ, June 5, 2006, Newsletter).

Vietnam refining industry gets oil supply deal

Petrovietnam Trading Co., an affiliate of Vietnam Oil & Gas Group (PVN), has signed an agreement with the Trafigura Group of the Netherlands to supply oil for Vietnam's refining industry for 30 years and to cooperate in building oil storage facilities, transporting oil to refineries, and shipping oil and products.

State media reported that PVN also is considering investing in a 9 million tonne/year refinery and petrochemical complex in northern Vietnam, and a 10 million tonne/year facility and petrochemical complex in southern Vietnam.

In February, Vietnam Development Bank awarded a credit of $1 billion to state-owned Petrovietnam to finance construction of the country's first refinery at Dung Quat (OGJ Online, Feb. 13, 2007). ✦

Calendar

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

OIL&GAS JOURNAL online

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

2007

SEPTEMBER

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

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

Rice Engineering & Construction Forum, Houston, (713) 552-1236, ext. 3, (713) 572-3089 (fax), e-mail: riceglobalforum@theassociationnetwork.com, website: www.forum.rise.edu. 25.

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

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

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 877-8130 (fax), e-mail: registration@ecc-association.org, website: www.ecc-association.org. 27-28.

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OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ERTC Petrochemical Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 15-17.

xGPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 16.

Global E&P Technology Summit, Barcelona, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.eptsummit.com. 16-17.

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SPE/IADC Middle East Drilling and Technology Conference, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 22-24.

World Energy & Chemical Exhibition and Conference, Kuwait City, +32 2 474 8264, +32 2 474 8397 (fax), e-mail: d.boon@bruexpo.be, website: www.www.wecec-kuwait.com. 22-25.

Annual Natural Gas STAR Implementation Workshop, Houston, (781) 674-7374, e-mail: meetings@erg.com, website: www.epa.gov/gasstar. 23-24.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), website: www.lagcoe.com. 23-25.

Pipeline Simulation Interest Group Annual Meeting, Calgary, Alta, (713) 420-5938, (713) 420-5957 (fax), e-mail: info@psig.org, website: www.psig.org. 24-26.

GSA Annual Meeting, Denver, (303) 357-1000, (303) 357-1070 (fax), e-mail: gsaservice@geosociety.org, website: www.geosociety.org. 28-31.

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Expandable Technology Forum, Reims, +44 (0) 1483 598000, e-mail: info@expandableforum.com, website: www.expandableforum.com. 30-31.

Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Oct. 30-Nov. 1.

Chem Show, New York City, (203) 221-9232, ext. 14, (203) 221-9260 (fax), e-mail: mstevens@iecshows.com, website: www.chemshow.com. Oct. 30-Nov. 1.

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Journally Speaking

Jonah mitigation science

Paula Dittrick
Senior Staff Writer

Oil and gas operators acknowledge the need to restore or create wildlife and plant habitat to counterbalance what has been lost to drilling and development.

Wyoming's Jonah gas field operators are no exception as they recruit scientific advice on ways to improve backcountry settings around Pinedale, Wyo.

Jonah field drilling has disrupted pronghorn migration routes and destroyed wintering grounds and breeding sites for greater sage grouse.

Mitigation is a way of compensating for what was lost to energy development. Mitigation can occur on a development site (onsite mitigation) or elsewhere (offsite mitigation).

A key question concerning offsite mitigation is where and when it can be used.

Jonah offsite mitigation involves acquiring nearby acreage to be preserved for use by the pronghorns and sage grouse.

Other offsite mitigation practices could include removing invasive plants and burning certain areas to encourage the growth of native plants.

EnCana Oil & Gas (USA) Inc., BP America Production Co., and other companies operating in Jonah field provided $24.5 million in offsite mitigation funds. The federal government manages much of Jonah field's surface and mineral rights.

BP America provided a grant to Nature Conservancy scientists who are developing a regional framework to help the Jonah Interagency Reclamation and Mitigation Office (JIO) with decisions about allocating the mitigation funds.

The JIO considers proposals from various conservation organizations seeking financing. The JIO includes representatives from the Wyoming Department of Environmental Quality, Wyoming Department of Agriculture, Wyoming Game and Fish Department, and the US Bureau of Land Management.

Conservation science

Conservancy scientists are working on a methodology to develop specific conservation goals to be used as guidance for the JIO's distribution of the Jonah mitigation money.

Joe Kiesecker, the conservancy's lead scientist in Wyoming, said similar methodology eventually might be applied to other regional fields.

"Mitigation of energy development can no longer be an afterthought. Before development occurs, industry needs to look at the site and plan to avoid sensitive areas," Kiesecker said.

Oil companies are uncomfortable agreeing to finance offsite mitigation without a plan guiding the mitigation, he said.

BP invited the conservancy's involvement in Jonah field, he said. Since 1978, BP and its affiliates have contributed $8 million to the conservancy.

For Jonah, scientists used information from environmental impact statements and looked at lists of biological targets. They overlaid species-specific habitat maps with maps of Jonah field.

Scientists say Jonah gas field drilling has disturbed sage grouse and their breeding habitat. Photo by Joe Kiesecker, Nature Conservancy.

The process is aimed at setting goals for the number and distribution of conservation targets in specific areas.

An important factor of offsite mitigation is the method of selecting suitable offset sites. Scientists used a Marxan model to select areas representing the biology of Jonah field.

Marxan is a tool for landscape conservation analysis that explicitly incorporates spatial design criteria into site selection.

The scientists acquired and developed maps of the species and habitat identified on Jonah. The species are the burrowing owl, cedar rim thistle, mountain plover, pronghorn, pygmy rabbit, sage grouse, sage sparrow, white-tailed prairie dog, and Wyoming big sagebrush.

The species-habitats information was plugged into the Marxan model. Scientists also used predictive models to estimate the acreage of impacted habitat and to search for suitable offset sites for mitigation.

BLM decision

The BLM issued a Jonah infill drilling project record of decision in March 2006 following analysis of a final environmental impact statement. The FEIS analysis said onsite mitigation efforts were inadequate.

That decision resulted in the formation of mitigation funds.

The BLM said site-specific mitigation measures can be applied throughout a project.

Upon completion, all wells would be plugged and abandoned, surface facilities would be removed, and remaining disturbed areas (with the exception of certain road improvements) would be reclaimed and revegetated, a BLM document said. ✦

attend in person or online!

November 28, 2007 | Houston, Texas | Omni Hotel

www.drytreeforum.com

The fourth DryTree & Riser Forum will be held in Houston, Texas this year at the OMNI Hotel on November 28, 2007. This year's theme, "Deeper Water - Practical Solutions," will present practical experiences relating to choices when choosing drytree production systems and deepwater riser systems. During this one-day forum, speakers and delegates will explore the technology, tools, decision-making processes, and functional requirements of the concept selection and execution employing drytrees and various riser systems.

Additionally, the first six presentations are made available through a live webcast from the conference floor and participants will be able to attend and ask pertinent questions and share insight during the first half of the conference. The final six presentations are closed to press to ensure that the extremely topical discussions and timely nature of the conference material is maintained.

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7:00 - 8:00 am	Registration & Continental Breakfast
8:00 – 8:15 am	Welcome & Opening Remarks
8:15 – 9:45 am	Session 1 & Live Webcast
9:45 – 10:00 am	Coffee Break
10:00 – 11:30 am	Session 2 & Live Webcast
11:30 – 12:30 pm	Lunch
12:30 – 2:00 pm	Session 3 (closed session)
2:00 – 2:15 pm	Coffee Break
2:15 – 3:45 pm	Session 4 (closed session)
3:45 – 4:00 pm	Closing Remarks
4:00 – 5:00 pm	Networking Reception

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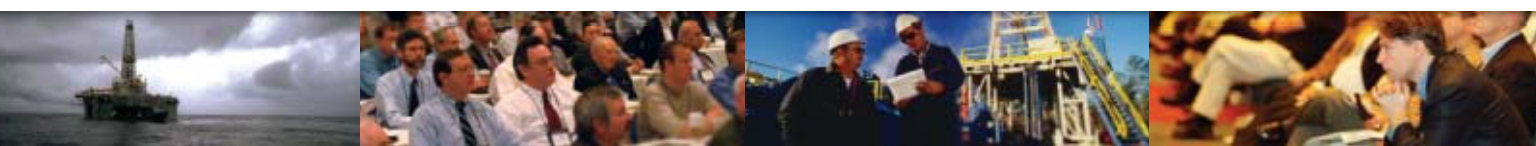


Editorial

Biofuels meet doubt

Finally, the worldwide biofuels frenzy has encountered quasi-official doubt. Even better, the doubt emerged in a forum dedicated to sustainable development.

"Biofuels: Is the Cure Worse than the Disease?" asks the title of a paper issued this month by the Round Table on Sustainable Development at the Organization for Economic Cooperation and Development (OECD), Paris. Attention to the question is overdue.

Countries around the world seem determined to join the US as it jumps over the biofuels cliff. The US government, of course, has installed a generous system of tax credits, tariffs, and sales mandates to expand markets for fuel ethanol and biodiesel. The supposed reasons are to extend supplies of vehicle fuel, moderate air pollution, and reduce emissions of greenhouse gases. The real reason is to enrich grain growers, distillers, and biodiesel makers.

Political motives behind the US biofuels push haven't discouraged governments elsewhere, including Europe and China, from lavishing biofuels with incentives of their own. The US isn't the only country in which agriculture exerts strong political force.

Support and promise

Richard Doornbosch and Ronald Steenblik, who wrote the OECD group's paper, usefully relate government support to a reasonable assessment of biofuels' promise. "Biofuels may well play a part in expanding the range of energy sources available in the future," they write, noting that the role will depend largely on feedstock and production costs. "But in view of the fact that even the most optimistic studies posit no more than 13% of liquid fuel needs in 2050 being supplied by biofuels, it must be asked whether the diversion of such large amounts of public funds in support of this single technological option can be justified."

The projection they cite comes from the International Energy Agency. The authors call it realistic but possibly optimistic. They note that conventional ethanol and biodiesel are considered technically able to expand their combined share of the market to 11% in 2050 from 1% in 2005. But such growth would have "significant impacts on the wider global economy," including the elevation of food prices already in evidence.

Second-generation technologies, such as ethanol from cellulose, are considered technically able to meet 12% of liquid-fuel needs by 2050. But they depend on uncertain technical development and must overcome the costs of moving biomass to large production plants. "This leads some to believe that the second-generation biofuels will remain niche players, produced mainly in plants where the residue material is already available in situ, such as bagasse (cellulosic residue from sugarcane processing) and wood-process residues," Doornbosch and Steenblik write.

The authors challenge environmental arguments made in support of biofuels. They cite land-use strains and increased fertilization associated with expanded production of biomass feedstocks. And they argue that substantial cuts in greenhouse-gas emissions come only from ethanol produced with sugarcane or as a byproduct of cellulose production and from biodiesel made from animal fat and used cooking oil.

The paper further challenges the efficiency of government policies encouraging and protecting domestic production of biofuels. Usage mandates or blending percentages and fuel-tax preferences usually don't account for differences in environmental costs and benefits among various feedstocks and production methods. Those differences can be great, the paper notes, adding, "This implies that governments could end up supporting a fuel that is more expensive and has a higher negative environmental impact than its corresponding petroleum product."

Costs high

As greenhouse-gas reducers and petroleum substitutes, biofuels are expensive, the authors say. They estimate the cost of reducing greenhouse-gas emissions through US subsidies of corn-base ethanol at "well over" $500/tonne of carbon dioxide equivalent avoided. And in terms of displacing fossil fuels, they say, "In most cases the use of biofuels roughly doubles the cost of transportation energy for consumers and taxpayers together."

More withering words such as these fill the report's 57 pages. They leave no doubt that the OECD's Round Table on Sustainable Development judges the rush to biofuels to be environmentally and economically unsustainable. As evidence mounts of high costs and false promises, the craze should prove to be politically unsustainable as well. ✦

POINT OF VIEW

More growth seen in use of geophysical methods

Bob Tippee
Editor

The use of geophysical methods has spread from the fringes of exploration to the heart of reservoir management during a quarter-century of technological expansion that the incoming president of the Society of Exploration Geophysicists expects to continue.

Fred Aminzadeh, president and chief executive officer of dGB-USA, Sugar Land, Tex., sees potential for seismic and other geophysical applications in areas from which they're now absent.

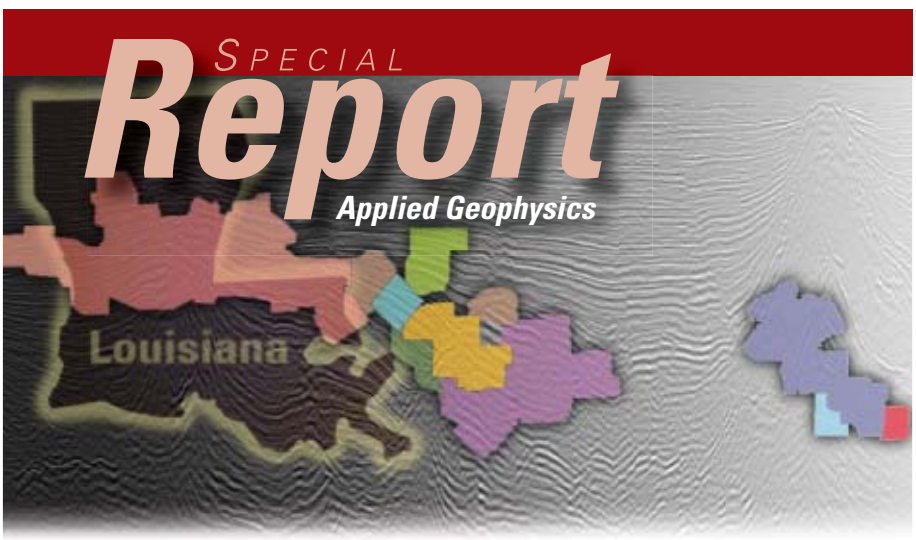
One such area is reserves certification. Aminzadeh wants SEG to be included in the reserves committee comprising the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, and American Association of Petroleum Geologists.

And he thinks the US Securities and Exchange Commission, which audits reserves disclosures by publicly traded oil and gas producers, should apply geophysical methods in its studies, incorporate geophysical advances of the last 30 years in regulations and requirements for reserves disclosures, adopt "resource" disclosure criteria, and add a geophysicist to a staff now dominated by engineers.

"Most of the reserves certification laws or parameters or guidelines were written 20 or 30 years ago, when there was no 3D or 4D seismic, when there was no three-component, four-component, or any of the advanced techniques that have come up," Aminzadeh says.

In an interview, the new SEG chief made clear that the evolution of geophysical technology guides his thinking on a range of subjects, including integration of oil-field operations and data, interdisciplinary training, and communicating—to the oil and gas industry and beyond—what his profession can do.

"It is our responsibility to make sure that we convey the correct image regarding what we do, what type of thing we offer, what type of major impact that we can make and are making, whether it is reducing finding costs, or whether it is reducing production costs or placement of wells," he says.



Modern methods

In the assessment of reserves and resources, Aminzadeh says, modern geophysical methods reduce uncertainty about the four main risk factors: structure, reservoir, seal, and charge.

Three-dimensional seismic techniques, for example, greatly improve the precision and accuracy of interpretations of reservoir structure, including depth, shape, and lateral extent, Aminzadeh notes.

And interpretation based on amplitude variation with offset (AVO) and other seismic attributes has become an effective way to address reservoir risk. AVO makes use of differences in the reflection signal strength that occur as distances vary between shot and receiver points (offsets). Analysis of those changes can yield reservoir information such as lithology and fluid content.

Aminzadeh says gas-chimney technology, combined with techniques for accurately mapping faults, can help assess the other main risk elements: seal and charge.

Gas-chimney technology identifies migration of natural gas through subsurface strata, either vertically or along faults.

"All of these advances have made it possible for geophysicists to help get a better handle on those parameters that eventually go into reservoir risking and reserve calculation," Aminzadeh points out.

Geophysical techniques also can help establish new criteria for "resource certification," he adds. The criteria would encompass properties that can be proven to show a "reasonable chance" for discovery of hydrocarbons that can be developed into proved reserves.

"If you want to have a correct valuation of the company," he says, "you should be able to have some number that financial communities can put their hands on and see that the company does not have any production but has some resources."

Dynamic characterization

In the field, seismic applications have advanced beyond the static analysis of reservoirs to what Aminzadeh calls "dynamic reservoir characterization."

Four-dimensional (sequential 3D) surveys can show "not only what the reservoir looks like and what its properties are right now but how it is evolving through time," he explains.

The value of 4D seismic acquisition and interpretation points toward "the instrumented oil field," in which companies leave seismic geophones or hydrophones in place for multiple surveys.

While the technology has been applied in a few, mostly offshore fields, the instrumented oil field "is not as common as you would like it to be," Aminzadeh says. "In today's economic structure you need to have a really large field to make economic sense."

As computer technology lowers costs, however, instrumentation will increasingly become part of field design. This will increase the use of other techniques that remain for now in a category Aminzadeh calls "boutique activity."

One seismic method likely to benefit in this manner is multicomponent (vector wave field) acquisition and processing. Another is elastic wave inversion, a method of deriving subsurface density and as well as compressional and shear velocity profiles from seismic data.

"With all the advances in seismic technology, still we need complementary geophysical data to better evaluate our fields," Aminzadeh says. "Such recent success stories include controlled-source electromagnetic and borehole gravity data."

> "It is our responsibility to make sure that we convey the correct image regarding what we do."
>
> **—Fred Aminzadeh, president and chief executive officer, dGB-USA**

Integrating disciplines

Additional complementary data come from operations other than geophysical work and from professionals other than geophysicists.

This fusion of various data types requires the intelligent integration of disciplines, according to the new SEG chief.

"Geophysicists by themselves can't do the job," he says. "Geologists by themselves can't do the job, geochemists, well log analysts, petroleum engineers...."

In a 1996 article in the Journal of Petroleum Science and Engineering, Aminzadeh proposed that the disciplines of geoscientists and engineers be integrated, rather than simple data integration, in the manner that their work was being integrated in the early stages of exploration and production.

"We will be forced to bring down the walls we have built around classical disciplines such as petroleum engineering, geology, geophysics, and geochemistry or at the very least make them more permeable," he wrote.

More than 10 years on, some of those walls remain.

"In order to make this integration work, you need to have a group of people that have some reasonable knowledge of other disciplines," Aminzadeh says. Achievement of that aim requires adaptation of the educational system. Medical schools provide a model.

"They train generalists before they go to a specialty," he says. "We probably should take a page from their book and try to train for some more general-purpose type work for industry professionals, which I call 'geo-engineer.' This has already started happening."

Aminzadeh relates integration of disciplines and interdisciplinary education to his appeal for refinement of the image that geophysics projects to other oil and gas professionals, regulators, and a public needing energy.

"The best way to get the image right is to train people," he says. And training

about energy—and the technology and people that produce it—should start early.

"If we are serious about energy independence and making sure that we have energy for future generations then we need to have investment in education from very early on, including from high school."

Career highlights

Fred Aminzadeh is president and chief executive officer of dGB-USA, Sugar Land, Tex., and president of the Society of Exploration Geophysicists.

Employment

Aminzadeh has held his current position with dGB-USA since 1999. Before joining dGB he worked 17 years with Unocal Corp. in various positions, including manager of geophysical technology. He has written 11 books and holds many patents. He has been an adjunct professor at Rice University and a consultant to several US national laboratories.

Education

He holds a PhD in geophysics from the University of Southern California. His dissertation was on elastic wave modeling, with applications in AVO and elastic impedance calculation.

Affiliations

Aminzadeh has been a member of SEG for 30 years and is a past chairman of the SEG Research Committee and vice-chairman of the Global Affairs Committee. He served as SEG vice-president in 2001-02 and received SEG's Special Commendation Award in 1998. He also belongs to the American Association of Petroleum Geologists, Society of Petroleum Engineers, and European Association of Geoscientists and Engineers. He has served on the National Research Council Committee on Seismology and currently serves on the Department of Energy's Unconventional Research Technology Advisory Committee. He is a fellow of the Institute of Electrical and Electronics Engineers and a member of the Azerbaijan Oil Academy and Russian Academy of Natural Sciences.

Future methods

Aminzadeh sees geophysical methods advancing on a number of fronts—some pushing them further into operations in which they haven't been used much, if at all, before.

The acquisition of seismic data during drilling, for example, can improve targeting and identify overpressured zones ahead of the bit. Aminzadeh holds the patent for a method of guiding oscillating wellbores during drilling with seismic data from energy generated by the drillbit and recorded by geophones in the well being drilled or in a nearby well.

Improvements are still needed in the imaging of geologic strata below salt, basalt, and other hard rocks, he notes. Research has yielded solutions to some of the sonic-velocity problems that confound the positioning of reflections below complex structures. Further improvements might come from surveys that use "very, very large offsets to shoot underneath these otherwise impermeable [salt] boundaries."

Another area ripe for further improvement is imaging of fractures and "a better understanding of hydrocarbon-bearing fractures vs. closed fractures," Aminzadeh says.

Unconventional oil and gas resources represent an area in which "geophysicists have a big role to play." The SEG president says, "Our members need to push the limits of application areas of their technologies outside the conventional resources."

Emerging microseismic techniques might help with the imaging of fractures and unconventional reservoirs, such as tight shales and coalbed methane. In microseismic work, geophones continuously record energy from natural vibrations in the subsurface or from field operations such as frac jobs and production.

Other trends Aminzadeh considers important are the increased availability of open-source software, which brings new tools quickly to practical use.

'Geomentoring'

With technology moving in so many directions and with rapid demographic changes in the industry workforce, the new SEG president proposes a program he calls "geomentoring."

The age distribution of the SEG membership has "a large hole" in the 30-45-year range, he notes.

"My vision of geomentoring is a program that would cover a large spectrum: technical issues, career issues, and many other things, including how to become active in professional societies, how to publish, how to decide on a career path, how to define 'success' for yourself, how to reach that success, among other things," Aminzadeh says.

"The challenge is how best to channel the large reservoir of wisdom and experience with a strong sense of altruism that our more senior members have to those who can benefit from them. If successful, the result will be a self-perpetuating fountain of geophysical knowledge."

Aminzadeh notes that a recent SEG investment in online capability will help advance the vision.

"That's one thing I'm very keen on," he says. ✦

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Shale plays send PGC's US gas resources estimates higher

Nick Snow
Washington Correspondent

Shale gas plays in four US Midcontinent basins provided most of the impetus as estimated US natural gas resources grew dramatically from the end of 2004 to the end of 2006, the Potential Gas Committee said in its latest biennial report.

Total domestic gas resources, including proved reserves, were an estimated 1,525 tcf as of Dec. 31, 2006, about 16.6% more than the 1,308 tcf PGC estimated 2 years earlier. It was the largest volumetric and percentage growth in the group's biennial estimate since 1968.

"The industry is looking at gas shales nationwide. It's the hottest kind of new play," observed John B. Curtis, director of the Colorado School of Mines' Potential Gas Agency, which assists PGC's efforts. Although US shale-gas production dates back to the 19th century, "it's coming of age today as a result of higher prices, improved technology, and greater understanding of the formations and what's required to tap them," Curtis told reporters during a briefing at the American Gas Association, one of PGC's sponsors.

Excluding proved reserves, as estimated by the US Department of Energy (204.4 tcf in 2006 and 189 tcf in 2004), yearend potential US gas resources climbed 18% to 1,321 tcf from 1,119 tcf over 2 years, PGC said. Traditional resources, which include carbonates and tight sands, climbed 21.6% to an estimated 1,155 tcf at yearend 2006 from 950 tcf 2 years earlier.

Coalbed methane resources declined 1.9% to an estimated 166 tcf from 169 tcf during that same period, according to PGC. Curtis said this reflected heavy production as operators aggressively developed the resource.

Other committee officials agreed. "I think it's maturing. Operators have been chasing CBM for 5-10 years," said PGC Chairman Michael K. Decker, who also is executive vice-president and chief operating officer of Gasco Energy Inc., Englewood, Colo.

Midcontinent shales

The excitement over CBM's potential during the 1990s has shifted to shales, due largely to successes in the Midcontinent's Arkoma, Anadarko, Fort Worth, and Permian basins, PGC said. But the formations, while prolific, can be hard to produce. "Shale wells typically produce small volumes. A field can require a lot of wells and a lot of infrastructure," Curtis said.

But the potential extends to other regions. "The Rockies are just getting started. There could be a major increase there from shale gas in another 2 years," said Decker. Drilling a well to a shale formation there can cost $8 million, compared to $2-3 million for a shallower conventional well, he said.

Gasco recently completed its first shale gas well in Utah's Uinta basin with satisfactory results and one of its competitors, Questar Resources, has drilled four and may drill another, Decker said.

The committee, which draws its members from the gas industry, academia, and government agencies, does not consider access, politics, or price in its estimates. It does try to avoid deposits which are unlikely to be produced for technical reasons.

"Because so many of our members work the basins for a living, the estimates use a realistic cost-to-production ratio. The gas is technically recoverable, but economies vary by company," said Curtis.

As technology improves, however, resources can move from being speculative to being possible or probable, he continued. "The Powder River basin is an excellent example. When the first wells were drilled there, it was thought they'd never produce. Now, after the application of new technology, two new wells are drilled weekly there," he said.

Others warned that federal policy actions could increase domestic demand for gas. "If Congress looks at carbon constraints, it should look very carefully at natural gas supplies. In our view, it hasn't," said Chris McGill, AGA's managing director of policy.

"The treatment of access has been very uneven. It is a problem," he added. ✦

Oil supplies expected to remain tight despite OPEC decision

Nick Snow
Washington Correspondent

Crude oil supplies are expected to remain tight despite the Organization of Petroleum Exporting Countries' decision Sept. 11 to increase authorized production by 500,000 b/d starting Nov. 1, two US government forecasters said.

Most outlooks already included such an increase when OPEC took its action, according to Matt Cline and Erik Kreil, economists at the US Energy Information Administration. "We'd built another 500,000 b/d into our forecast. We think OPEC will have to keep raising production to keep inventories from plummeting," Kreil told OGJ on Sept. 14.

In its latest short-term energy outlook, which EIA released on Sept. 11, the US Department of Energy forecast and analysis division reduced its projection for OPEC crude oil production in the fourth quarter by 100,000 b/d from its previous monthly forecast to 30.9 million b/d.

The expected decline stems from planned oil field maintenance in the UAE. Kreil said weekly impacts could be higher since the estimate represents a 3-month average. Even factoring in the reduction, EIA forecast average OPEC production during the fourth quarter will be 500,000 b/d higher than a year earlier, he added.

Outside OPEC, EIA also reduced its average 2007 production growth estimate by 100,000 b/d from its August short-term outlook to 600,000 b/d. Anticipated production declines in Mexico as its producing region recovers from damage caused by Hurricane Dean represent about 51,000 b/d of the downward revision, Cline said.

Recent attacks on pipelines should not affect Mexico's oil exports, he told OGJ. "They will have more of an impact on the country's refineries. The impact will be on world product markets as [Mexico's state-owned Petroleos Mexicanos] puts out tenders for products from the United States and other countries to compensate for reduced refinery runs," Cline said.

Most of the remaining reduction in EIA's projections for non-OPEC production growth reflects declining production from maturing fields and other natural occurrences, he added.

EIA anticipates that expected gains in demand for OPEC oil will likely keep surplus production capacity within the cartel at 2-3 million b/d through 2008, mostly in Saudi Arabia. "The modest level of worldwide surplus capacity makes the market vulnerable to unexpected supply disruptions," it said in its latest short-term outlook.

Unlike many private analysts and the International Energy Agency, EIA focuses on commercial inventories, according to Kreil. It does not rely on official government announcements for its OPEC production estimates but uses independent sources instead, he explained.

"We're assuming that the situation in Nigeria is not going to get any better. It's confusing in terms of spare capacity, which many people want to use. We don't. We expect [the unrest and disruptions] to continue so we're keeping our basic assumption unchanged until we see a dramatic improvement. The same is true with Iraq," Kreil said. ✦

Franco-Iranian relations cool over nuclear goals

Eric Watkins
Senior Correspondent

Franco-Iranian relations appear to have reached a turning point.

The French government reportedly is applying pressure on Total SA and other oil and gas firms to freeze all investments in Iran in an effort to force Teheran into giving up its uranium enrichment program and nuclear ambitions.

The daily Le Monde newspaper reported Sept. 18 that the recommendation falls within the framework of an allegedly tougher political stance toward the Islamic republic by French President Nicolas Sarkozy.

The paper said the chief executive of a French business group acknowledged that the French ambassador to Iran emphasized at a recent meeting that the situation is "not favorable" for business. For example, the executive told Le Monde, the Iranians had put oil and gas exploration blocks out to auction in August, but only Austria's OMV group had responded.

OMV had signed an agreement in April with Iran's National Oil Co. (NIOC) for possible investment in developing Iran's offshore South Pars gas field. But the US has been threatening OMV with retaliatory measures and is trying to deter other Western and Japanese companies from investing in the Iranian hydrocarbons industry.

Total SA is most affected by the changed political atmosphere. The effort to produce and liquefy Pars gas represents seven structural projects that Total wants to develop in 2010-30.

But the firm apparently has little chance of successfully completing them. "The way in which talks with Iran's national company are progressing does not allow (us) to launch the project for the moment," a company spokesperson said.

Total General Director Christophe de Margerie favors reviewing the agreements, which are valued at $10 billion, saying in early 2007, "These development costs have more than doubled, and this is a real subject of concern for us."

Total, which has a 30% stake in the projects, had planned to invest $3 billion there along with NIOC, Malaysia's Petronas, and a fourth partner.

Gaz de France also is interested in the project and would invest some $300 million, but, according to Le Monde, France's political instructions are curbing its ambitions as well.

Total has been delaying its decision to invest due to concerns over the rising dangers of the nuclear issue and the change of attitude by the French government. ✦

Italy, Kazakhstan to meet to resolve Kashagan issues

Eric Watkins
Senior Correspondent

Italian Prime Minister Romano Prodi plans to visit Kazakhstan next month in an effort to resolve a disagreement over delays and cost increases in developing the giant Kashagan oil field.

Prodi's office said the visit, set for Oct. 7-9, was planned but not scheduled long before the dispute arose late last month between the Kazakh government and Italy's Eni SPA (OGJ Online, Aug. 28, 2007).

Attempting to downplay any sense of crisis, Prodi said that his trip would deal with more than oil and that his country and Kazakhstan enjoy excellent relations.

Kazakhstan wants to increase its share of future profits from the oil field to 40% from 10% as compensation for repeated delays by the Eni-led consortium in developing it.

Kazakhstan also wants state-run Kazmunaigaz to be made a joint operator of the project along with Eni.

The Kazakh government has suspended development of the Kashagan project for 3 months, and it has threatened to extend the suspension beyond October if the two sides cannot come to terms.

Eni executive Paolo Scaroni met with Kazakh Prime Minister Karim Massimov and expressed confidence that negotiations would proceed concerning operations at the oil field. The next day, however, Massimov said a friendly settlement compensating for the delays must be reached by Oct 22.

Eni has delayed twice the field's start

of production; first to 2008 from 2005, and then to 2010.

Kazakhstan also has expressed concern over the rising estimates of the project's cost, which has more than doubled to $136 billion from the original $57 billion.

Ahead of Prodi's planned visit, Kazakh lawmakers are in the process of adopting an amendment that will allow the government to annul contracts of strategic importance if the contract conditions are not met and national security or economic interests are threatened.

Kazakh lawmaker Valeriy Kotovich said the amendment, for which the government has already expressed its approval, is likely to be passed by the end of September.

Observers say the amendment could have serious consequences for the current dispute between Kazakhstan and the Eni-led consortium, easing the government's ability to make legal changes in contract terms. ✦

Judge tosses California vehicle emissions lawsuit

Paula Dittrick
Senior Staff Writer

A US district judge in San Francisco has quashed California's lawsuit against major automakers regarding vehicle emissions.

US District Judge for the Northern District of California Martin Jenkins ruled Sept. 17 that the state of California was trying to "punish (automakers) for lawfully selling their automobiles."

Jenkins said federal lawmakers—not judges—should decide if auto manufacturers are responsible for what California Att. Gen. Jerry Brown has called greenhouse gas emissions-related problems. The lawsuit sought millions of dollars in damages, citing drought, beach erosion, and warmer temperatures.

"The court finds that injecting itself into the global warming thicket at this juncture would require an initial policy determination of the type reserved for the political branches of government," Jenkins said.

He approved a motion from automakers to dismiss the case. Defendants were General Motors Corp., Ford Motor Co., the US division of DaimlerChrysler AG, Toyota Motor Co., Honda North America, and Nissan North America.

In a separate case, US District Judge Williams Session III of Burlington, Vt., ruled Sept. 12 that the state of Vermont can regulate GHG emissions from vehicles. His ruling came in a 240-page decision following a 16-day trial that ended in May.

During the Vermont trial, auto industry executives testified that regulations by Vermont, California, and other states would not stop global warming but would impose prohibitive costs on auto manufacturers.

California, Vermont, and 10 other states want to impose tougher standards on vehicle emissions than federal regulators require. The proposed GHG laws by states cannot take effect until the US Environmental Protection Agency grants a waiver requested by California under the Clean Air Act (CAA).

The other states are Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington..

The California legislature passed a GHG law in 2002 requiring automakers to reduce vehicle emissions 30% by 2016. The state filed its request for an EPA waiver in December 2005 and still awaits an answer from the EPA. Approval of California's waiver means the other states would get approval automatically (OGJ, June 25, 2007, p. 31).

Meanwhile on Apr. 2, the US Supreme Court ruled that the EPA has the authority, under the CAA, to enact limits on carbon dioxide emissions (OGJ, Apr. 9, 2007, p. 33). That lawsuit was filed by Massachusetts and other states. ✦

MMS, Burlington settle gas royalty dispute

Burlington Resources Oil & Gas Co. has agreed to pay the federal government more than $97.5 million, plus interest, to settle several natural gas royalty issues on federal and American Indian lands, said the US Department of the Interior's Minerals Management Service, which filed a district court complaint against Burlington under the False Claims Act (FCA).

Per the settlement agreement, the accrued interest would be for the period of Sept. 1, 2006, until final payment is made. This will result in a total settlement amount of slightly more than $105 million.

"This settlement should serve as a strong reminder that MMS will aggressively pursue all royalties due to the government from production that occurs on federal and American Indian lands," MMS Director Randall Luthi said.

The agreement covers natural gas production that occurred from Mar. 1, 1988, through Mar. 31, 2005, for the improper valuation of the gas from coal seams, and from Mar. 1, 1988, through Dec. 31, 1997, for under-reported value

of conventional gas and natural gas liquids.

In addition to resolving the FCA complaint, the settlement also resolves several "orders to pay" that MMS had previously issued to Burlington beginning in the 1990s. Those orders addressed nonallowable or excessive deductions for processing and transportation, including the cost of removing carbon dioxide from the gas. MMS has maintained, and recent court rulings have affirmed, that those costs must be paid by the company and cannot be deducted from royalty payments.

About $94.5 million of the settlement will be allocated to federal leases in New Mexico, which will be split between the federal government and the state of New Mexico.

In addition, MMS will disburse portions of the settlement to a federal lease in Colorado and federal leases in Oklahoma, to the Jicarilla Apache Nation, to the Ute Mountain Ute Tribe, to Indian mineral owners in the Concho and Anadarko areas in Oklahoma, and to individual Navajo mineral owners in New Mexico. ✦

ONGC plans $30 billion investment in 2007-12

Shirish Nadkarni
OGJ Correspondent

India's Oil & Natural Gas Corp. (ONGC) plans to invest $30 billion during its 11th 5-year plan (FYP) covering fiscal years ending in 2012.

This investment total is 60% more than that of the prior FYP. It follows ONGC's recent offshore gas discovery in the Krishna Godavari basin and the success of its overseas subsidiary ONGC Videsh Ltd. (OVL; OGJ, Jan. 15, 2007, Newsletter).

OVL will invest 453.34 billion rupees in the upcoming FYP, compared with 250.52 billion rupees in the 10th FYP. Its downstream group, Mangalore Refinery & Petrochemicals Ltd., will invest 83.16 billion rupees, compared with 7.65 billion rupees under the previous plan.

The company's fiscal 2006-07 exploratory efforts led to 22 discoveries, of which nine were new prospects—three deepwater, one shallow-water, and five onshore, said R.S. Sharma, ONGC chairman and managing director.

"A total of 88 exploratory and 178 development wells were drilled in fiscal 2006-07," Sharma said. "We recorded the highest in-place reserves accretion in the last 11 years—169.52 million tonnes of oil equivalent." He said the company was looking at "in-place volumes of more than 100 million tonnes" from the discoveries.

"We are looking at production of over 140 million tonnes of crude oil and 112 billion cu m of gas during the 11th plan," he said.

ONGC no longer plans to build a 3-4 million tonne/year refinery in Rajasthan, saying the project, like an earlier dropped plan for a 7.5 million tonne/year refinery, is not economically viable (OGJ, July 24, 2006, Newsletter).

Gas from the Krishna-Godavari basin is expected to start flowing in 2012. Development plans for gas finds in Block KG-DWN-98/2 will be complete by yearend 2008. ONGC has made six gas discoveries on the block, the largest being one discovered in December 2006, which holds probable in-place reserves of 2.08 tcf.

Deepwater collaborations

ONGC is collaborating with Norsk Hydro Production AS, Eni, British Gas, and others—mostly for deepwater exploration and production.

Hydro will extend technical support to develop deepwater oil and gas blocks off India and has agreed to acquire a participating 10% interest in ONGC's KG-DWN-98/2 deepwater block in the Krishna Godavari basin on which ONGC recently struck gas.

ONGC held that block on a nomination basis before the advent of the New Exploration Licensing Policy (NELP). ONGC has 32 offshore exploration blocks under NELP, with 12 in ultradeep water, 14 in deep water, and 6 in shallow water. It holds 100% participating interest in 12 of the 26 deepwater blocks.

An investment cap of $26 million would be imposed during the appraisal phase, with an option to increase the holding by another 10%. ONGC said Hydro may seek participating interests in other ONGC NELP blocks once the companies examine data during the next 6 months.

The agreement envisages cooperation between ONGC and Hydro in developing India's continental shelf.

ONGC plans to utilize the expertise of the Norwegian company on development and production from deep water and ultradeep water and "thin oil development and production" in Vasai East, near Bombay High. ✦

Approval, gas sales boost Australian LNG plans

Rick Wilkinson
OGJ Correspondent

The Gorgon LNG project off Western Australia, with facilities on Barrow Island, has moved a step closer to implementation, having received preliminary environmental approval for two trains of 5 million tonnes/year each.

However, a new scoping study has led the Chevron-led Gorgon partners—Royal Dutch Shell PLC, Chevron Corp.,

and ExxonMobil Corp.—to consider adding a third train to produce a total of 15 million tonnes/year of LNG. If that decision is made, it would require further environmental studies and approvals.

Meanwhile, China has forged two sales deals for Western Australian LNG this week—the strongest sign yet that Gorgon will move forward.

Shell Australia concluded a binding heads of agreement to sell PetroChina 1 million tonnes/year of LNG for 20 years, primarily from Gorgon gas. A detailed agreement will be conditional on the Gorgon partners reaching a final investment decision before December 2008.

Shell also still has preliminary agreements to send Gorgon gas to India and to an import terminal in Baja California.

Browse basin gas

The second sales deal, for Browse basin gas, was reported in Sydney Sept. 6.

Woodside Petroleum Ltd. agreed to key terms with PetroChina for the potential sale of 2-3 million tonnes/year of LNG over 15-20 years from Woodside's Browse project, which includes the development of Torosa (formerly Scott Reef), Brecknock, and Calliance (formerly Brecknock South) gas fields some 430 km north of Broome off Western Australia. The three fields have gas reserves of about 20 tcf and lie in water averaging 800 m deep.

The agreement, which hinges on a final investment decision for the Browse project, anticipates deliveries start-up in 2013-15. Although terms were kept confidential, the expectation is for revenues of $35-45 billion (Aus.).

Woodside and partners BHP Billiton, Chevron, BP, and Shell aim to have determined an optimum development concept for Browse basin fields during 2008.

The interests in the various permits over the field areas vary, but Woodside has just under 50% overall. Although the latest agreement is with Woodside, it provides for the addition of LNG entitlements for the other partners to be commingled in sales. ✦

COMPANY NEWS

GDF, Suez merge into major gas distributor, utility

Gaz de France and Suez, following approval of their boards and shareholders, reported Sept. 3 a merger of equals set to become the largest gas transmission and distribution network operator in Europe, the number two storage and LNG terminal operator in Europe, and one of the three top utilities worldwide.

In other recent company news:

• Videocon Industries and Bharat Petro Resources Ltd.—a subsidiary of India's Bharat Petroleum Corp. Ltd. (BPCL)—have entered into an agreement to purchase shares of Brazilian exploration EnCana Brasil Petroleo Ltda. (EBPL) from Canada's EnCana Corp. and 749793 Alberta Ltd.

• Abu Dhabi National Energy Co. (ADNEC) has agreed to buy Pioneer Natural Resources Canada Inc. from Dallas independent Pioneer Natural Resources Co. for $540 million.

• BreitBurn Operating LP, Houston, signed a definitive agreement to acquire all properties held by Quicksilver Resources Inc., Fort Worth, in Michigan, Indiana, and Kentucky for $750 million in cash and 21.348 million common shares of BreitBurn Energy Partners LP.

• Centrica PLC has agreed to acquire Newfield Exploration Co.'s remaining interests in the UK North Sea for $486.4 million.

• A federal district judge in Dallas issued a temporary restraining order and asset freeze against two small oil and gas companies and a Los Angeles man in response to US Securities and Exchange Commission allegations of stock manipulation and fraud.

GDF-Suez merger

France's Parliament has voted to privatize GDF, and France will hold a 35% stake in the merged Franco-Belgian group, to be called GDF SUEZ, which will have a combined stock market capitalization of €90 billon, revenues of €72 billion, a cash flow of €11.4 billion, and less than €13 billion in net debt.

Current Suez Chairman and Chief Executive Gerard Mestrallet will be chairman and chief executive, running the group jointly with GDF Chairman and Chief Executive Jean-Francois Cirelli as vice-chairman and president.

The merger should become operational by mid-2008.

The European Union Commission's late 2006 approval requires Suez to divest its 57.25%-owned gas marketing subsidiary Distrigaz and its 57% stake in Belgium gas transport company Fluxys. Suez will divide Fluxys into three entities, keeping a majority stake only on the Zeebruggen methane terminal. Fluxys will operate the Zeebrugge hub.

Suez also will spin off 65% of its environmental division. GDF Suez will control it through a shareholder pact involving the remaining 35% to be negotiated.

GDF will relinquish its 25.5% stake in Belgium electric power company Societe Publique d'Electricite and will divest Cofatech Coriance, its district heating subsidiary.

Videocon-Bharat JV buy EBPL

Videocon and Bharat's acquisition of EBPL is estimated at $425 million, of which $165 million would be paid

immediately and the balance invested in exploration.

EBPL holds varying interests in 10 ultradeepwater exploration blocks in four concessions off Brazil, seven of which are operated by partner Petroleo Brasileiro SA (Petrobras). Anadarko Petroleum Corp. is the fourth partner in EBPL.

An EnCana spokesman said the company was exiting Brazil to concentrate on North American unconventional gas and integrated oil sands resources.

Indian companies have stepped up their pace of foreign acquisitions, striking deals valued at more than $16 billion through August of this year, up from $6.2 billion during the same period a year earlier, according to Dealogic.

Both Videocon and BPCL have been eyeing global oil equity. Although consumer business accounts for 90% of Videocon's $3.68 billion, the oil business brings in more than half its profits, so the company is seeking to increase its interests in the oil business.

BPCL, focused on refining and marketing petroleum products, embarked on the acquisition of oil exploration assets to offset losses from selling petroleum products below cost. It will spend as much as $370 million on exploration over the next 3 years, targeting small development stakes and producing fields.

The refiner recently bought equity in three blocks in the North Sea in collaboration with Tata Petrodyne and has gathered stakes in 14 oil and gas blocks in India, West Africa, South America, and Australia since it began its oil equity drive.

ADNEC to buy PNRC

ADNEC previously announced plans to expand internationally, particularly in Canada.

In May ADNEC marked its entry into Canada by agreeing to buy Calgary-based Northrock Resources Ltd. for $2 billion from Pogo Producing Co. of Houston (OGJ, June 11, 2007, p. 32).

ADNEC, an energy investment company and global conglomerate, was formed 2 years ago. The Abu Dhabi government owns 51% of the company.

BreitBurn's acquisition

BreitBurn's purchase of Quicksilver's assets includes more than 5,400 producing wells, related gas gathering and processing systems, and Quicksilver's interests in 260,000 net undeveloped acres as of Dec. 31, 2006. Proved reserves are 539 bcf of gas equivalent, 94% gas.

The properties produced a net 75.4 MMcf of gas equivalent in the first half of 2007, or 38% of Quicksilver's total production in the period.

Quicksilver said the deal will better prepare it to develop its large inven-

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Terrorists aim at key systems

The al-Qaeda terrorist group, which has long eyed ways of interfering with the oil and gas industry, continues to threaten world peace. But it is hardly the only show in town, as one expert has recently testified.

John Robb, the author of a respected new book on terrorism, last week warned in Oklahoma City that extremists of the future will attack oil refineries, natural gas pipelines, and other targets that provide vital systems to society.

"You can make these attacks far removed from where we're at, and because of all the systems being interconnected it will have an impact on us," Robb said in an interview with the Oklahoman newspaper.

The man has earned his stripes, too. A graduate of the US Air Force Academy, Robb served in a tier-one counterterrorist unit that worked closely with Delta and Seal Team 6. Robb participated in global operations as a mission commander, pilot, and mission planner.

Global guerrillas

Three or 4 years ago, Robb started a blog called "Global Guerrillas" in an effort to catalog and describe the evolution of system disruption and open-source warfare within the Iraqi insurgency and around the world.

Speaking at the Oklahoma City University School of Law last week, Robb said Americans could be paying as much as $10/gal for gasoline if a 2006 attack on a major Saudi Arabia refinery had succeeded.

This strategy of "systems disruption" has been seen in Iraq, Nigeria, Brazil, Mexico, and elsewhere, he said, adding that small terrorist groups are learning from each other, using technology, and evolving their tactics.

"Something works, everyone else adopts it," he said. And, not least important, he noted that, "Very seldom do you see any of the attackers being caught." Sound familiar?

If not, consider the Ejercito Popular Revolucionario (EPR), a secretive Marxist group that killed dozens of police and soldiers in the late 1990s. It's back at work in Mexico, and its work is causing havoc to the country's oil and gas industry.

The EPR strikes

On Sept. 10, the EPR hit the Mexican economy hard when it set off six explosions in Veracruz which damaged a dozen gas pipelines and one oil duct, temporarily halting industrial activity in 10 states and causing hundreds of millions of dollars in losses.

Pemex itself was suddenly in the market for 300,000 bbl of oil products to supply the domestic market amid refinery snags. The Mexican firm had to reduce production at its 320,000 b/d Tula refinery by 50% after the pipeline explosions reduced crude supplies to the plant. Its 245,000 b/d Salamanca refinery was also affected, reducing crude runs by 32,000 b/d.

Very clearly, this was systematic destruction by the EPR based on key intelligence, and it underlines Robb's view that, "A small attack—something that cost a couple of thousand bucks to do—can have many million percent in return." ✦

tory in the Fort Worth basin and other areas.

Centrica's UK deal

Newfield's sale of its UK North Sea assets is expected to close in the fourth quarter pending UK government approvals. With the sale, Newfield effectively exits from the North Sea.

The sale includes an 85% interest in Grove field, which came on stream in April; an 80% interest in the undeveloped Seven Seas discovery; and an interest in about 200,000 net acres in the Southern Gas basin.

Newfield's production guidance had accounted for this and other divestiture programs and remains 240-253 bcf of gas equivalent for 2007 and 215-230 bcf of gas equivalent for 2008.

SEC alleges stock fraud

US District Judge Barbara M.G. Lynn of the Northern District of Texas issued the order and freeze Sept. 12 against Terax Energy Inc. of Dallas, Westar Oil Inc. of Beverly Hills, Calif., and Mark Roy Anderson. SEC also ordered a 10-day suspension of Terax's stock, which trades on the over-the-counter bulletin board.

In its complaint, SEC alleged that Anderson gained control of Terax in April. Soon after, the company issued several press releases, which the SEC said were false and misleading, regarding Terax's oil and gas operations and the company's stock price increase to as much as $4.88/share from 30¢/share.

SEC also alleged that Anderson conducted a fraudulent private placement of $1 million of Westar's common stock and made false claims about its oil and gas operations and plans to exchange Westar stock for Terax stock.

SEC said it is seeking permanent injunctions against and civil fines from Terax, Westar, Anderson, as well as Linda Contreras, Anderson's assistant, for violating registration provisions of the 1933 Securities Act. It also seeks disgorgement from Terax, Westar, Anderson and two relief defendants, which it said Anderson controls. ✦

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Creating new geography: Seismic image processing illuminates new opportunity space in S. Louisiana

Edward A. Duncan
Swift Energy Co.
Houston

Scott Scholz
John Branca
Swift Energy Operating LLC
Houston

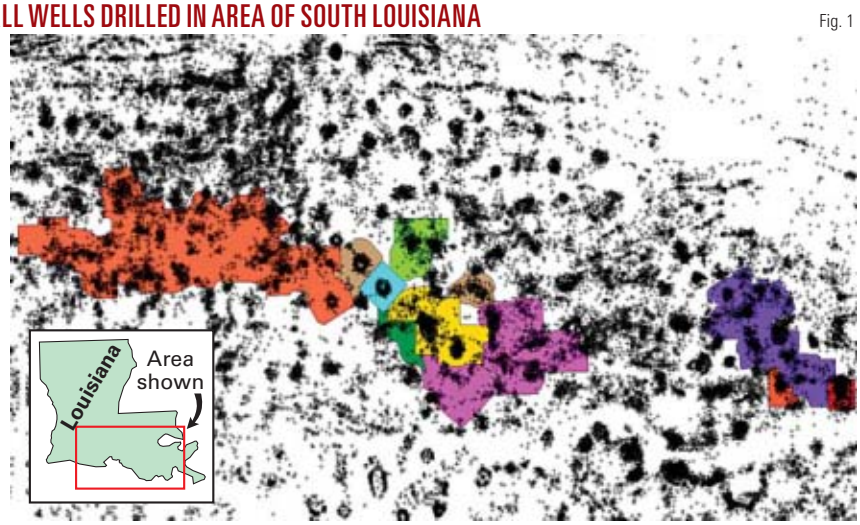
Southern Louisiana is one of the most prolific petroleum provinces of the world. Proven plays have produced billions of barrels of oil and continue to provide sustainable opportunities for a broad cross section of the industry.

Even with all that has been produced, significant reserve adds for exploration and development companies are available in this region through a range of workflows from complex reservoir remediation projects in older fields to conventional new field wildcat exploration activity adjacent to and below existing production.

These efforts yield better results when the geoscience and engineering professionals can actually see what they are attempting to exploit. At Swift Energy, seismic and depth imaging of the regional geology of South Louisiana, as it has never been im-

ALL WELLS DRILLED IN AREA OF SOUTH LOUISIANA

Fig. 1



aged before, has "created new geography" to develop and explore.

The Northern Gulf of Mexico basin margin, including the area of present-day South Louisiana, during the Late Cretaceous through Tertiary, can best be characterized as an unstable, rapidly subsiding, progradational, terrigenous clastic passive margin. The depositional environments and trapping configurations are heavily influenced by gravity and salt withdrawal tectonics.

Regional source rocks underlie the entire area, and complex burial history including broad areas of salt driven basin "downbuilding" create aggradational stacks of reservoirs from shallow depths to well beyond present depths of well penetrations. The predominantly vertical flux of migrating hydrocarbons provides pervasive charge to reservoirs in developed trapping geometries. These are all viewed much more clearly with imaging technology available today, and thus become "new geography."

At Swift Energy, we believe the pursuit of "material" reserve growth does not require a move into deep water or politically unstable business environments outside the US. While creating new geography, we have armed our oil and gas professionals with state of the art data and a leading edge analytical toolkit. 3D-based seismic depth imaging technology coupled with sound petroleum systems science is leading the way toward realization of a robust, sustainable opportunity set.

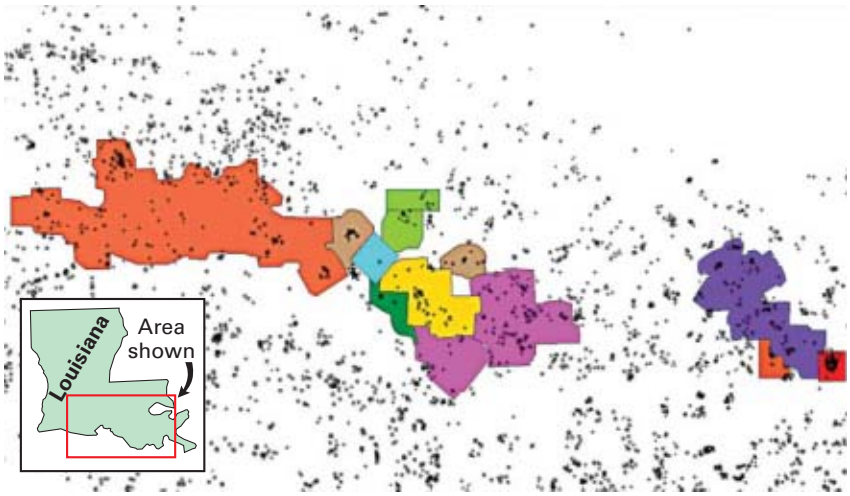
Play-based approach

Successful exploration strategies are based on the premise that maximum value and leverage are created when a company is successful in a new basin or new play by accessing a dominant acreage position early in new play development.

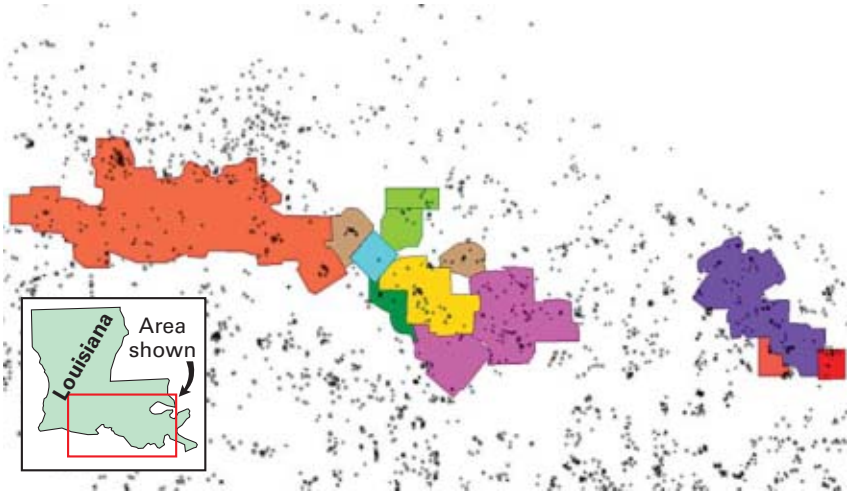
Following recognition, access, and the initial testing of new play systems, early activity is the high-value growth phase (typically the first 5 years) during which the largest fields in the play trend tend to be found.

Once the largest reserve fields are

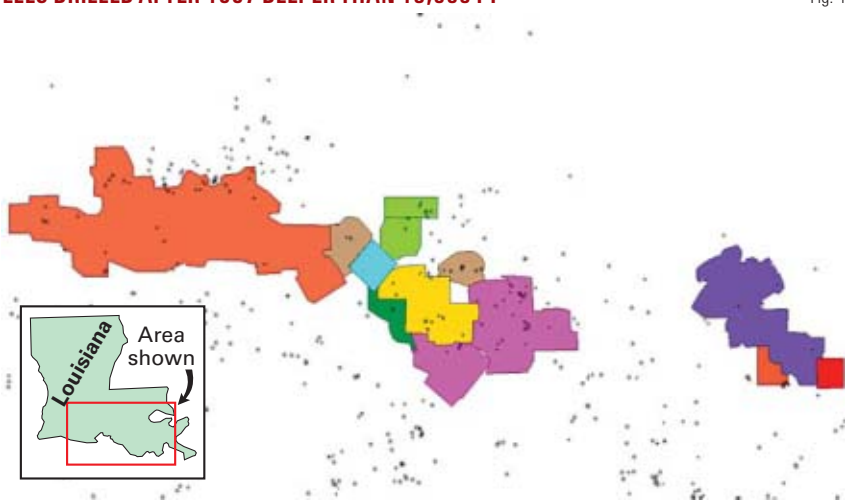
WELLS DRILLED AFTER 1997 IN SOUTH LOUISIANA Fig. 2



WELLS DRILLED AFTER 1997 DEEPER THAN 10,000 FT Fig. 3

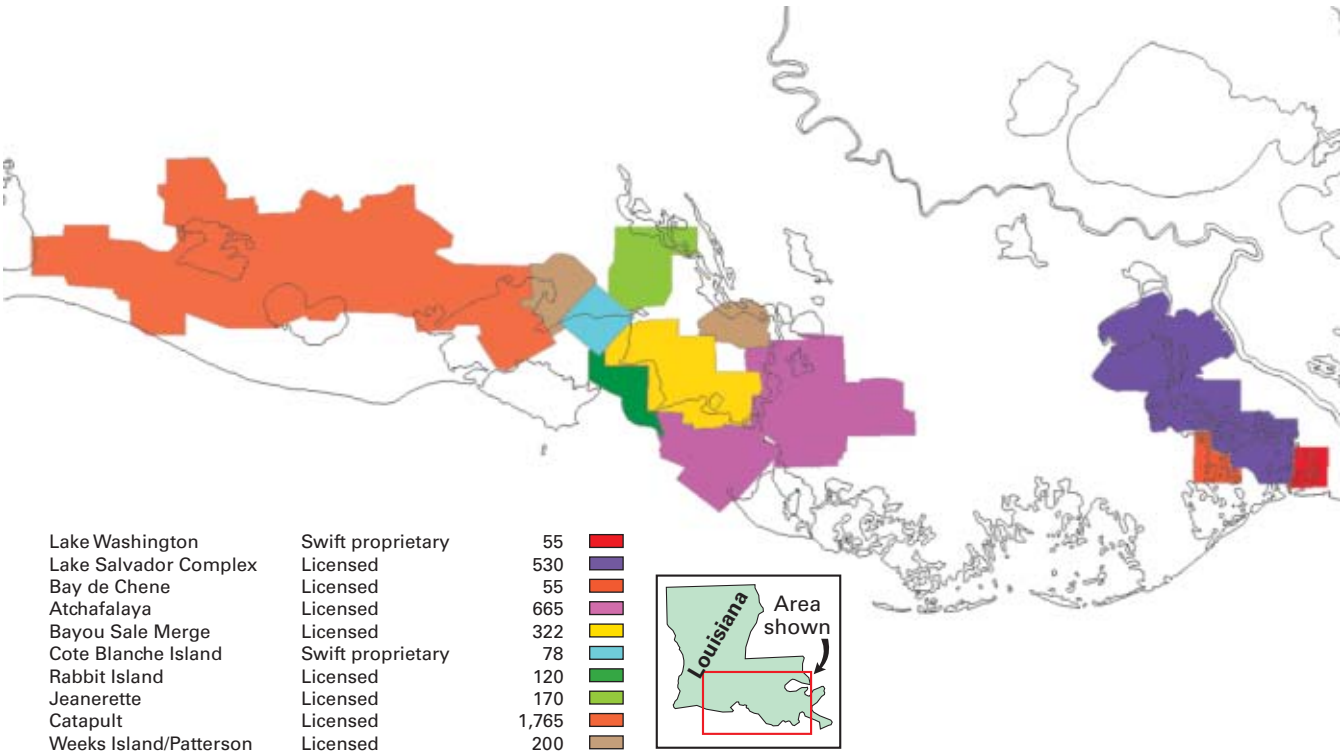


WELLS DRILLED AFTER 1997 DEEPER THAN 16,000 FT Fig. 4



SWIFT ENERGY'S SOUTH LOUISIANA 3D SEISMIC DATASET

Fig. 5



Lake Washington	Swift proprietary	55
Lake Salvador Complex	Licensed	530
Bay de Chene	Licensed	55
Atchafalaya	Licensed	665
Bayou Sale Merge	Licensed	322
Cote Blanche Island	Swift proprietary	78
Rabbit Island	Licensed	120
Jeanerette	Licensed	170
Catapult	Licensed	1,765
Weeks Island/Patterson	Licensed	200

discovered, value can still be added, but generally at a progressively lower rate, as the field reserves remaining to be proven diminish in size. This second phase of play maturation is currently taking place in the deepwater Gulf of Mexico. During this phase, companies can fall into a trap of overinvesting in proven plays and begin to destroy value. In other words, capital expenditures chasing reserves in these so-called "nonmaterial" areas begin to exceed the value of the reserves they are adding.

The budgets of most exploration companies reflect broad differentiation of stages in the exploration and development-led value creation cycle. The guiding principle is that new basin/new play activity is the true foundation of the oil and gas exploration business and must be preserved.

It is play fairway analysis that drives technical and business work. Play fairway analysis enables a company to understand the phases of exploration and development value creation so that resources are directed toward the right play fairways, with the right work program to maximize value.

Value locked up in competitor acreage can be unlocked by acquisition, a key element of Swift Energy's strategy. Value can also be unlocked in company-held leases in perceived high-value play fairways by review and sometimes new data collection. Value locked up in drillable prospects can be unlocked by an aggressive drilling campaign.

The key is having a tool that allows the company to properly perceive value in its own properties and in the acreage positions of others. Swift Energy's regional 3D database has enabled our technical teams to assess not just our own position, but many others as well.

The core of a successful exploration and production business, but also the challenge, is to build a link between the technical foundation provided by play fairway analysis with the currency of our business, that being acreage acquisition, drilling, and dispositions. Play fairway analysis is a critical technical tool in determining exploration and development business strategy.

The technical foundation provided by play fairway analysis is the identification of risk and the highgrading of areas for effective reservoir, petroleum charge, and regional seal. Play fairway analysis seeks to identify areas where these model elements provide for a highly material, commercially robust activity set.

New geography identified through 3D seismic-based depth imaging technology enables play fairway analysis to be performed at a higher level of confidence not possible in the past using older technologies.

Play fairway analysis and risk assessment

The objective of Swift Energy's technical efforts is to explore efficiently

by investing capital in new geography where our teams can better identify the most favorable, material expected outcome.

In pursuit of this goal, the exploration and development team's ultimate challenge is to integrate diverse areas of technical knowledge into a working tool to be used by the business. The expected economic reward from exploration and development is determined by a combination of price, volume, and risk.

Although commodity prices are outside the control or influence of exploration and development companies, the volume and risk associated with the technical case can be assigned at a high degree of accuracy using new technologies and sound petroleum systems science.

Risk assessment

Volumetrics should be considered before finalizing the complete technical and commercial evaluation of any opportunity.

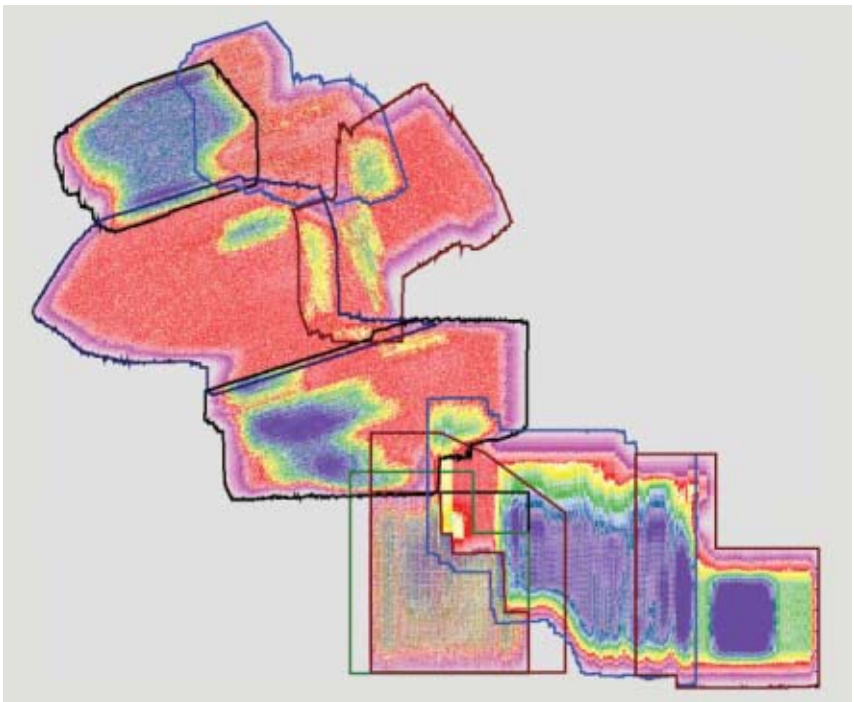
The absolute value of risk is determined based on a perceived volume within an opportunity. The probability of success represents the chance of successfully proving a volume of hydrocarbons that lies between determined minimum and maximum values.

The commonly expounded notion that finding moveable hydrocarbons or attaining flowing hydrocarbons to surface represents a "technical success" is logically flawed. Knowledge and confidence in the prediction of critical elements of risk play an important role in determining the range of outcomes, which then indirectly links knowledge, confidence, and risk.

The idea that complete technical risk is on a range of calculated volume outcomes and that it is only indirectly

Fold plot of typical Swift regional merge project*

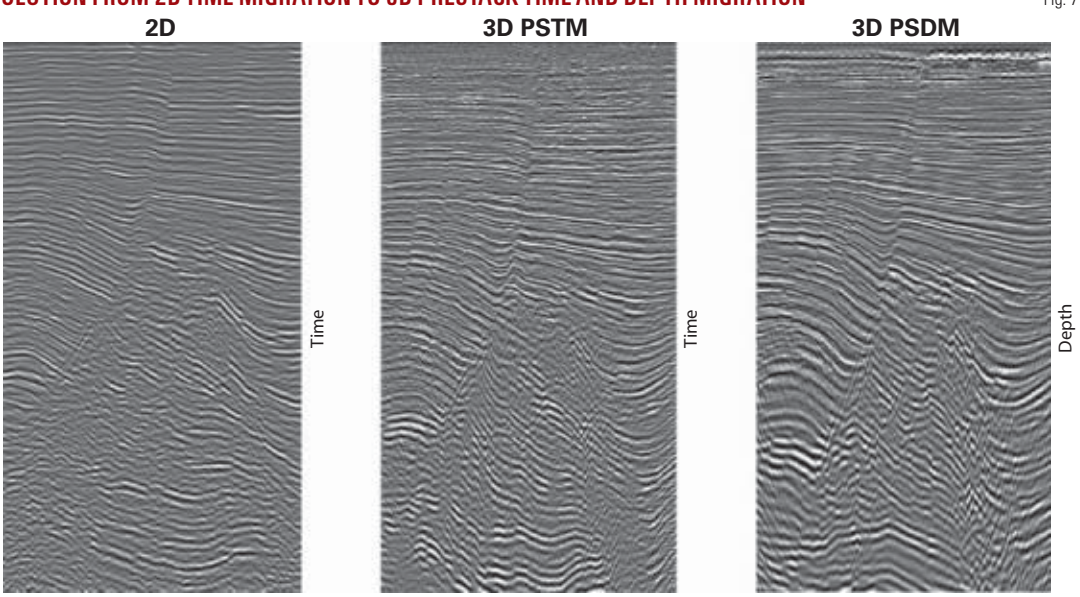
Fig. 6



*This plot is a combination of nonexclusive and proprietary 3D seismic data. This project consists of 10 disparate 3D surveys that were processed together and migrated into a continuous data volume. The merged data benefit significantly from migration halo that was not available when the data were originally imaged.

Evolution from 2D time migration to 3D prestack time and depth migration*

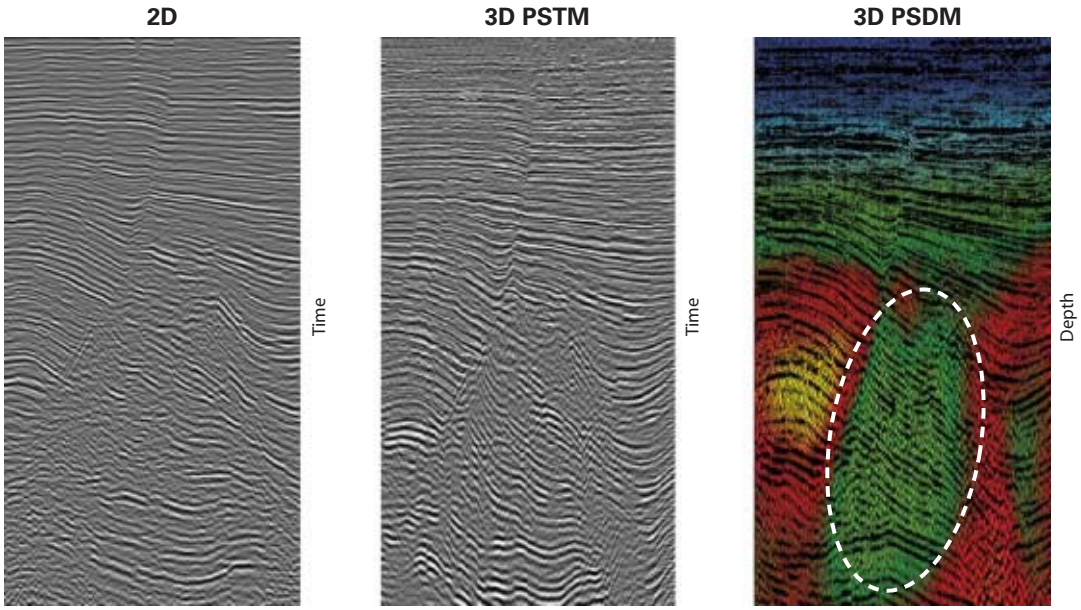
Fig. 7



*The 3D prestack time migration significantly improves reflector continuity and location. The 3D prestack depth migration reacts to a slow velocity anomaly and reverses the dip on the upthrown side of a pressure-bounding fault.

3D PRESTACK DEPTH MIGRATION WITH INTERVAL VELOCITY FIELD IN BACKGROUND*

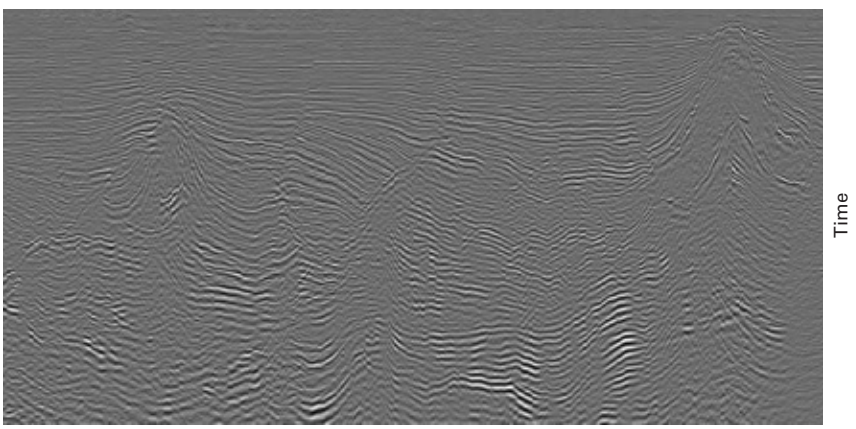
Fig. 8



*The green area within the dotted line details the low velocity zone.

'BEFORE' 3D PRESTACK TIME MIGRATION IMAGE *

Fig. 9



*A series of arbitrary lines in the regional megamerge illustrates the improvement in subsalt imaging and reflector placement with the use of prestack depth migration.

linked to knowledge are the two most common errors that enter into an exploration and development team's strategic planning. Prospect and lead reviews that discuss chance of success at a purely "technical" level increase the probability of misplaced effort toward nonmaterial ventures.

Many geological factors contribute to the risk of success on a given opportunity; thus all risking methods represent a compromise in that they aim to simplify the problem by identifying risk elements of common importance to all.

One particular problem with some methodologies is the inability to convey differences between prospects in proven and conceptual plays. This is a significant shortcoming, because it is beneficial to strategic planning in new play development or emerging areas if play risk (the chance that a play will work) can be separated from prospect specific risk (the average success rate given the play works).

Focus

Depth dependent, drilling density-based maturity screening illustrates that much of the depths below 16,000 ft in South Louisiana remain underexplored.

When chronology of the wells is factored in with drilling depth screening, it becomes very clear that an overwhelming percentage of the region has been drilled and exploited without the benefit of "modern" 3D depth imaged data. Most 3D data in South Louisiana has been acquired only since 1997.

When that fact is considered in the screening process, it becomes clear that in excess of 95% of the drilling in South Louisiana was targeted without 3D data and, more specifically, without high quality depth imaging. Figs. 1-4 illustrate the key facts that in South Louisiana, there are under exploited areas on the scale of international concession blocks at depths well within the exploitable petroleum system.

Merging and processing: Pictures say a thousand words

Swift Energy's strategic initiative has been and continues to be to assimilate, merge, and process proprietary and multivendor licensed 3D seismic datasets, creating a regionally uniform database of proprietary seismic data.

Where needed, Swift Energy creates proprietary 3D in key areas by either

conducting a 3D shoot or merging disparate, multivendor data sets. Lake Washington field, for example, had no 3D data coverage over the core of the field until Swift Energy conducted a shoot in 2004.

Leading edge application of depth imaging technologies has illuminated subtleties of the structural and stratigraphic architecture that often hold significant hydrocarbon accumulations. Fig. 5 illustrates the compositing of Swift Energy's seismic datasets in southeastern Louisiana.

Figs. 6-12 capture "before and after" snapshots that dramatically illustrate the improvement in depth imaging that Swift Energy has attained.

Technology and innovative application by skilled oil and gas professionals are the driving force in our industry. We believe it is key to focus on attacking reducible risks that have significant impact on the value creation process.

This focus on the key element of risk is greatly enhanced by the creation of new geography, rendering accurate depictions of the subsurface. The care taken in our imaging workflows facilitates higher end analysis at wavelet scale.

The result

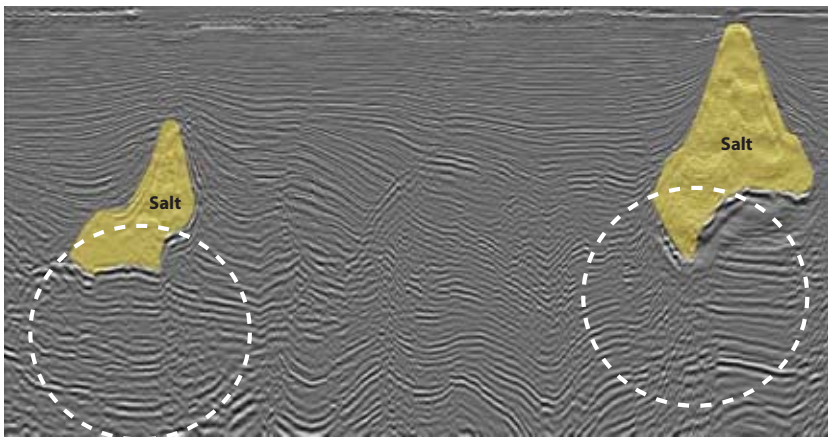
Swift Energy's teams delineate play-based, fairway-scale opportunity sets by imaging and mapping gross depositional environment and specific sediment fairways, along with detailed analysis of regional elements of the structural framework.

This pursuit of adding material hydrocarbon reserves is fundamentally tied to de-risking play fairway to prospect through comprehensive integration of borehole derived data and geophysics.

Swift Energy's commitment to technology-led strategic growth and recognition that the oil and gas industry is dependent on innovative application of petroleum systems science and engineering has empowered its oil and gas professionals to deliver value creation

'After' 3D prestack depth migration image*

Fig. 10

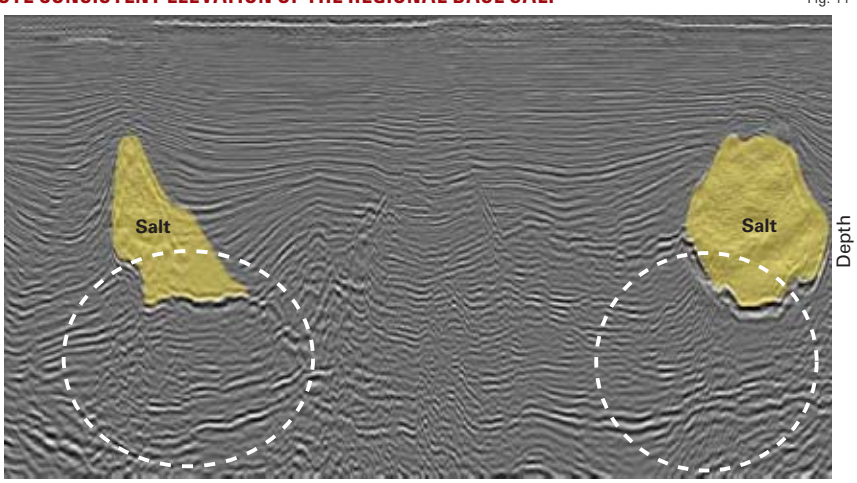


3D PSDM (arbitrary line 1)

*Greatly enhanced imaging of steeply dipping salt flanks and subsalt structure is the direct result of careful prestack processing workflows.

Note consistent elevation of the regional base salt

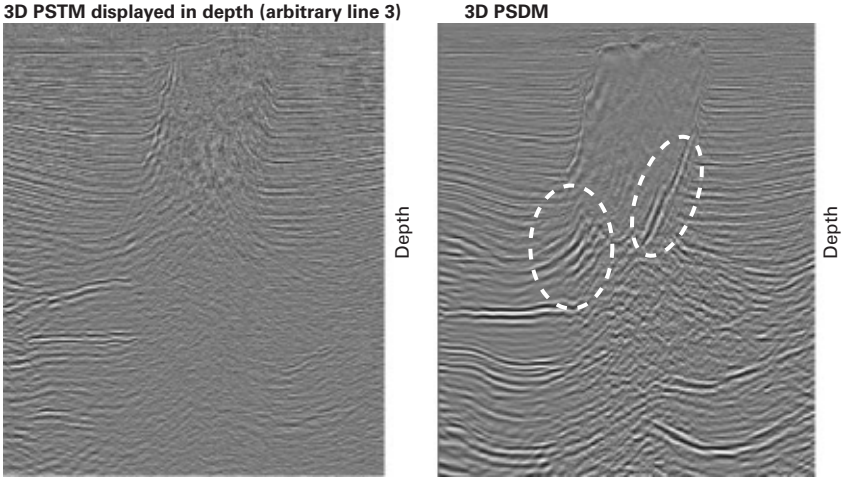
Fig. 11



3D PSDM (arbitrary line 2)

Dramatic improvement from prestack time to prestack depth

Fig. 12



opportunities. Collectively, we believe the effort builds toward material, commercial success.

Acknowledgments

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DRILLING MARKET FOCUS

Companies commit billions to offshore rig construction

Nina M. Rach
Drilling Editor

Drilling contractors and speculators have ordered 140 offshore rigs, to be delivered through 2011. In addition to new rigs, new yards are being built and old yards expanded or reopened. Existing rigs are scheduled for upgrades to accommodate new working environments and new rules, such as the mooring upgrades required in the Gulf of Mexico.

The deepwater rig market appears firm, with rates averaging about $250,000/day and highs reaching above $500,000/day. Newbuild additions are expected to be absorbed into the market without substantially lowering rates.

Although the jack up market is softening, average rates are still well above $100,000/day.

Fleet utilization

According to Rigzone, utilization of offshore drilling units remains high. Of the world's 35 drillships, 88.6% (31 ships) were working in July. Among 155 semisubs, 143 were working, representing 92.3% of the fleet. Of the 358 jack ups worldwide, 333 were working, or 93% of the fleet.

As of Aug. 24, about 88% (523 rigs) of the world's offshore fleet of 595 rigs was employed, up 2.5% from a year earlier, when 491 of the 574 rigs were being utilized.

SCORE increase slows

GlobalSantaFe Corp.'s summary of current offshore rig economics (SCORE) reached 136 in June 2007, up 2.4% from the previous month. The SCORE compares the profitability of current mobile offshore drilling rig day rates to the profitability of day rates at the 1980-81 peak of the offshore drilling cycle (when SCORE = 100).

The worldwide SCORE finally exceeded the benchmarks in November 2005 for semisubmersible rigs, and in December 2005 for jack up rigs. Both rig types began to level off in first-quarter 2006, and the increases slowed.

In June, the semisub SCORE reached 152.6, up 20% from a year earlier and up 281% from 5 years ago. The jack up SCORE hit 127, up 6% from a year earlier and up 169% over the past 5 years.

Regionally, the SCORE for West Africa (149, up 18.5% from a year earlier) and North Sea (146.7; up 8.7%) are highest. The SCOREs for Gulf of Mexico and Southeast Asia are nearly equal at about 120, with increases of about 4.5%/month. Southeast Asia, however, has shown a 33.6% improvement in the previous year, while the SCORE for the Gulf of Mexico hasn't really changed in 12 months, improving only 0.6%.

Worldwide SCORE for all regions and rig types is currently increasing at 2.4%/month and has increased 13.1% in the previous year.

Drilling fleets

With 140 drilling units under construction, the current global rig fleet is set to expand 18% beyond the 782 drilling units now on hand. Many of the new deepwater rigs are already under contract with operators.

There are 72 jack ups, 43 semisubmersibles, 19 drillships, 3 drilling tenders, and 3 inland barges now under construction, according to Rigzone (Table 1).

Jack ups—When Drilling Market Focus last reviewed new jack up construction a year ago, about $7.34 billion was committed to build the 61 jack ups then under construction (OGJ, Oct. 16,

Offshore rig fleets: September 2007

Table 1

Rig type	Current fleet size	Units under construction	Future fleet size
Jack ups	411	72	483
Semisubmersibles	167	43	210
Drillships	38	19	57
Tenders	26	3	29
Drill barges	48	0	48
Submersibles	7	0	7
Inland barges	85	3	88
Total	**782**	**140**	**922**

Source: Rigzone; Subsea.org; shipyard and operator announcements

The West Sirius is one of six semisubmersibles under construction for Norwegian drilling contractor Seadrill Ltd. (Fig. 1; August 2007 photo from Seadrill).

2006, p. 39). Seven jack ups were delivered in 2006, and 21 were scheduled to be delivered in 2007.

As of September 2007, the current fleet contains 411 jack ups; adding 72 newbuilds will increase it 17%, to 482. Two of the jack ups to be built for China Oilfield Services Ltd. are not yet committed to a shipyard, but most (35) are being built in Singapore: Keppel Fels leads with 20 jack up contracts, followed by PPL with 11, and Jurong with 4.

Five jack ups are under construction in Malaysia, at the Labroy and Labuan yards. Ten others are under way in the Persian Gulf, 10 in US shipyards, and 5 in China. Three are under construction in India: two at the ABG Shipyard and one at the Bharati Shipyard.

PPL announced a $198 million contract to build a Baker Pacific Marine Class 375 jack up announced in late August.

Semisubmersibles—The semisubmersible fleet is set to increase by 26%, when all 43 of the new units join the existing fleet of 167 (Table 2). Most of the rigs are being built in Singapore (15), China (11), and South Korea (8). A few are under construction at the IMAC shipyard in Abu Dhabi (3); the Severodvinsk, Sevmash, and Vyborg shipyards in Russia (3); the Aker yard in Verdal, Norway (2); and at Sadra's Nekkairan shipyard in the Caspian Sea (1). Two yards in the UK Haverton Hill and Teesside, are working with Russian yards on two of the semisubs for SeaDragon Offshore.

Norway's Seadrill Ltd. has six semisubs under construction; four in South Korea and two in Singapore, including the West Sirius (Fig. 1).

When Drilling Market Focus last tabulated semisub construction in June 2006, there were 26 semisubs under construction in five countries, exceeding $13 billion in orders (OGJ, June 19, 2006, p. 35). This was up from only four units under construction in 2005. Now we see 43 semisubs under construction in eight countries.

Drillships—There are an unprecedented 19 drillships under construction; 18 in South Korea and 1 in Spain (Table 3). Most (13) are contracted to Samsung Heavy Industries' Geoje yard. Four are being built by Daewoo Shipbuilding & Marine Engineering Co.'s yard in Okpo; one at Hyundai.

The hull for the multipurpose floater (MPF) 1000 drillship is under construction at the COSCO shipyard in China, where steel was cut in January 2007. The topsides are being built Dragados Offshore SA shipyard in Cadiz, Spain, and the ship will be delivered in 2008 (Fig. 2). The ship will have 1-million-bbl onboard storage for extended well tests.

OGJ's last tabulation of drillship construction showed only five ships under construction in Korea, at a cost of $2.46 billion (OGJ, May 8, 2006, p. 43).

Tender-assist rigs—Three drilling tenders are under construction, to be delivered in 2007-10 (Table 4). Saipem SPA's TAD-1 (tender-assist drilling) unit is under construction at the company's Boscongo Pointe Noire yard in the Congo. The tender can work in 450 ft water depth and will begin a 5-year contract with Eni Congo in fourth-quarter 2007. Eni SPA owns 43% of Saipem.

Seadrill has two tenders under construction. The T-11 will be delivered from the Malaysia Marine & Heavy Engineering yard in 2008 (Fig. 3). Seadrill Asia Ltd. has a semi-tender under construction at Keppel FELS in Singapore that will be delivered in 2010.

Inland barges—There are three inland barges under construction in a Gulf of Mexico yard for Inland Bay Energy Services. Rig 701 will be delivered this year; Rig 702 and 704 will be delivered in 2008. The barge derricks have 1.5-million-lb hookloads and triple 1,600-hp mud pumps.

Yards

Well-known shipyards are working at capacity and additional orders from burgeoning speculative building are going to new facilities.

In Singapore, Keppel FELS Ltd., a subsidiary of Keppel Corp. Ltd., is building 20 jack ups and 9 semisubmersibles. SembCorp Marine subsidiary Jurong shipyard is building 4 jack ups and 6 semisubs.

Keppel Offshore & Marine Ltd. opened a new shipyard in China in early August. The Keppel Nantong Shipyard Co. Ltd. yard, in Nantong, Jiangsu

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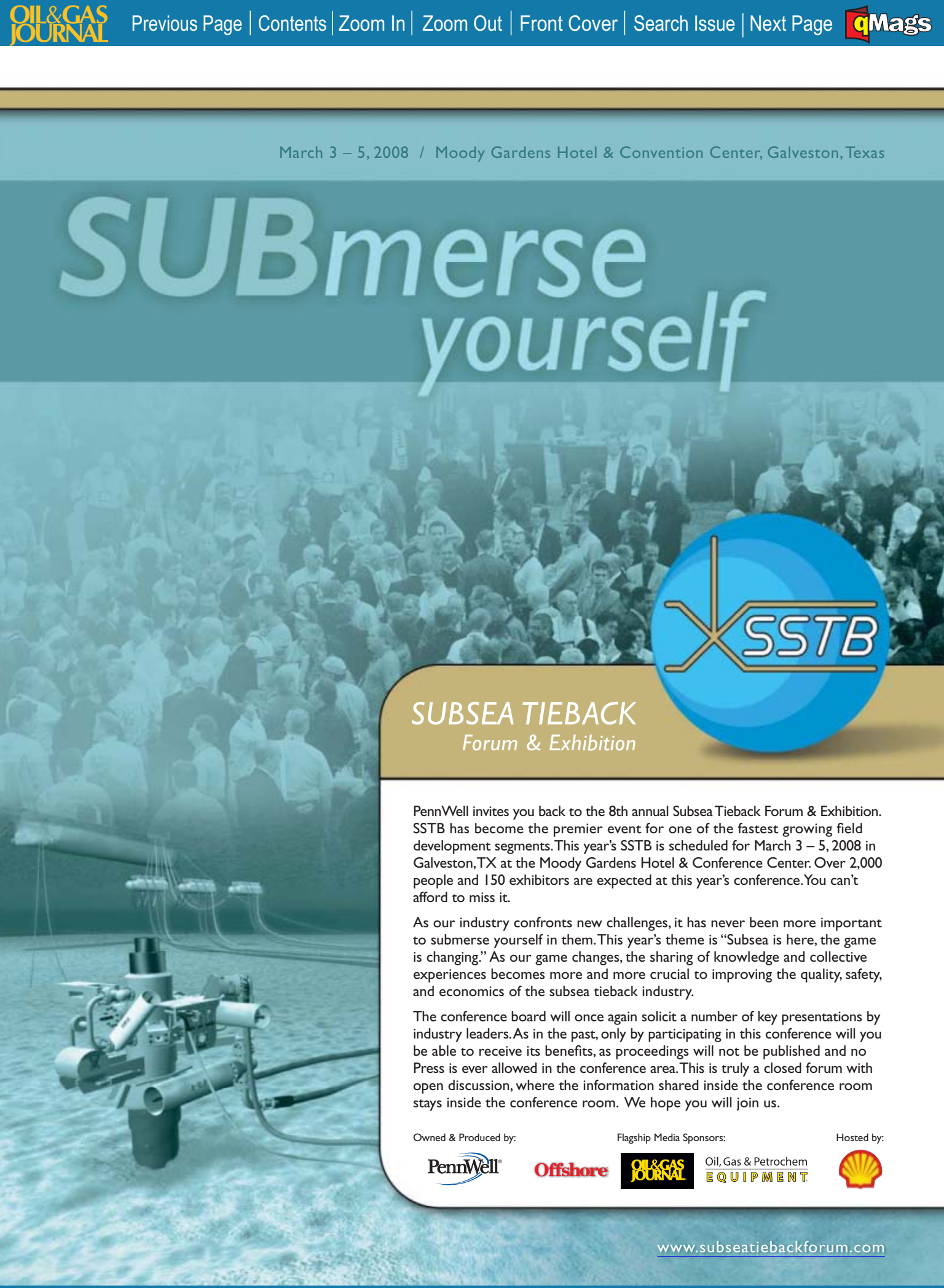

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SEMISUBMERSIBLES UNDER CONSTRUCTION*

Table 2

Rig name	Manager (owner, if different)	Design	Yard, location	Cost, $ million
2007 delivery (2)				
Iran Alborz	NIOC	Gotaverken GVA-4000	Sadra Shipyard at Nekkairan yard, Caspian	—
West Phoenix	Seadrill (Eastern Drilling ASA)	Moss CS50 MkII	Samsung Shipyard, South Korea	502
2008 delivery (12)				
Aker Barents	Aker Drilling AS	Aker H-6e	UAE and Aker Group yard, Verdal, Norway	575
Aker Spitsbergen	Aker Drilling AS	Aker H-6e	Aker Verdal, Norway	575
ENSCO 8500	ENSCO	E 7500E	KFELS, Singapore	312
Maersk Deepwater Semisub TBN I	Maersk Contractors	Marine Structure Consultants (MSC) DSS 21	KFELS	235 (hull)
Deepsea Atlantic	Odfjell	E 7500E	Daewoo, South Korea	—
WilInnovator	Premium Drilling (Awilco Offshore ASA)	GM-4000, DP3	Yantai Raffles Shipyard, China	—
WilPioneer	Premium Drilling (Awilco AS)	GM-4000, DP 3	Yantai Raffles	—
West Aquarius	Seadrill	Gotaverken GVA-7500-N	Daewoo	530
West Eminence	Seadrill	Moss CS50 Mk11-DP	Samsung	542
West Hercules	Seadrill	GVA 7500-N	Daewoo	512
West Sirius	Seadrill	Friede & Goldman (F&G) ExD	FG Offshore, Jurong Shipyard, Singapore	443
West Taurus	Seadrill	F&G ExD	FG Offshore, Jurong Shipyard	457
2009 delivery (20)				—
ENSCO 8501	ENSCO	Keppel FELS	KFELS	—
ENSCO 8502	ENSCO	Ensco 8500 series	KFELS	480
Frigstad Oslo	Frigstad Discoverer Invest Ltd.	HF Engineering Frigstad D90 DRR DP3	Yantai Raffles	—
GSF Development Driller III	GlobalSantaFe Corp.	MSC design	KFELS	—
Maersk Deepwater Semisub TBN II	Maersk Contractors	MSC DSS 21	KFELS	—
Noble Danny Adkins	Noble Drilling	Bingo 9000	Dalian Shipyard, China	—
Noble Jim Day	Noble Drilling	Bingo 9000	Dalian, China	—
Norbe VI	Odebrecht	Gusto TDS-2000PLus	IMAC Shipyard, Abu Dhabi	—
PetroRig I	PetroMena AS	F&G ExD	Jurong Shipyard, Singapore	400
PetroRig II	PetroMena AS	F&G ExD	Jurong Shipyard	400
Petroserv Semisub TBN 1	Petroserv SA	GVA 7500	Daewoo	—
WilPromoter	Premium Drilling (Awilco AS)	GM-4000-D DP 3	Yantai Raffles	—
Gold Star	Queiroz Galvao Perfuracioes	Gusto DSS-38	KFELS	—
Lone Star	Queiroz Galvao Perfuracioes	Gusto MSC TDS2000Plus	IMAC	—
Red Flag Semisub TBN 1	Red Flag AS	GM5000	Cosco (CFEM), , Zhoushan Shipyard, China	202 (hull)
Scarabeo 8	Saipem	—	Sevmash shipyard, Severodvinsk Russia	—
Schahin Semisub TBN 1	Schahin Cury	F&G Ex-D, Millenium, DP 2	FG Offshore, Yantai Raffles, China	—
Schahin Semisub TBN 2	Schahin Cury	F&G Ex-D, Millenium, DP 2	FG Offshore, Yantai Raffles,	—
Oban B	SeaDragon Offshore	Moss CS50 MkII	Sevmash; Haverton Hill, UK	—
Sevan Driller	Sevan Drilling	Sevan Stabilized Platform hull		—
2010 delivery (8)				
Delba Semisub TBN 1	Delba Perforadora Internacional SA	Gusto TDS 2000	IMAC	—
ENSCO 8503	ENSCO	Ensco 8500 series	KFELS	—
La Muralla III	Industrial Perforadora de Campeche	GVA 7500	Daewoo	—
Maersk Deepwater Semisub TBN III	Maersk Contractors	MSC DSS 21	KFELS	
Deepsea Rig 2	Odfjell	—	Daewoo	—
PetroRig III	PetroMena AS	F&G ExD	Jurong	—
West Orion	Seadrill	F&G ExD	FG Offshore, Jurong	532
2011 delivery (1)				
SDO II	SeaDragon Offshore	Moss CS50 MkII	Vyborg, Russia & Teesside, UK	
Total: 43 rigs				**7,124 for 16 of 43 newbuilds**

*Data from Rigzone, shipyard, operator, and contractor reports.

province, will build offshore support vessels such as anchor handling tugs and supply vessels and tugboats.

In China, Yantai Raffles is building six semisubs and one jack up. The Dalian yard is building 2 semisubs and 4 jack ups. Semisub construction is now nearly equal in Singapore (15) and China (11). The large demand for new jack ups has spread the contract work to Chinese and Malaysian yards.

The first jack up to be built in Malaysia's Labuan shipyard will be a Gusto MSC design, cantilever rig capable of working in 350-ft water for $155 million. The rig will be operated by a Malaysian-based joint-venture company formed between Iran's Tamin Oil & Gas Investment Co. (TOGICO) and SAAG Drilling and Well Services Sdn. Bhd., a subsidiary of Malaysia's SAAG Consolidated (M) Bhd. Keppel Oil International Ltd. signed a memorandum of understanding with TOGICO Aug. 5, but assigned rights, title interests, and benefits to SAAG in late August.

In South Korea, yards are capitalizing on experience in building drillships and have garnered contracts for 8 semisubs in the last year. Daewoo is building 6 semisubs and 4 drillships. Samsung is building 2 semisubs and 13 drillships.

J. Ray McDermott has a new fabrica-

DRILLSHIPS UNDER CONSTRUCTION: 2007*

Table 3

Drillship	Manager (owner, if different)	Design, class	Yard, location	Cost, $ million (shipyard)
2007 delivery (1)				
Stena DrillMAX I	Stena Drilling Ltd.	SAMS DS	Samsung Heavy Industries Co. Ltd., Koje yard, South Korea	600 (526)
2008 delivery (4)				
MPF 1000	MPF Corp. Ltd.	MPF 1000	Dragados Cadiz, Spain; hull by, Cosco Shipbuilding Group Ltd.	683 (245)
West Capella	Seadrill Ltd. (Mosvold Drilling Ltd.)	Samsung 10000E	Samsung	478
West Polaris	Seadrill Mosvold Drilling)	Samsung 10000E	Samsung	478
Stena Carron	Stena Drilling		Samsung	600 (550)
2009 delivery (6)				
Pacific Drillship TBN 1	Pacific Drilling Ltd.	Samsung 10000	Samsung	—
Pacific Drillship TBN 2	Pacific Drilling	Samsung 10000	Samsung, Geoje yard	—
Petrobras Drillship TBN 1	PNBV (Petrobras/Mitsui)		Samsung, Geoje yard	—
Stena DrillMAX III	Stena Drilling		Samsung	—
Discoverer Americas	Transocean Inc. (Pacific Drilling Ltd.)	Enhanced Enterprise	Daewoo Shipbuilding and , Marine Engineering Co. Ltd., Okpo, South Korea	—
Discoverer Clear Leader	Transocean (Pacific Drilling)	Enterprise	Daewoo	650 (470)
2010 delivery (8)				
Petrobras Drillship TBN 2	PNBV	—	Samsung, Geoje yard	—
Pride Drillship TBN 1	Pride International	SHI proprietary hull design	Samsung, Geoje yard	680 (612)
Pride Drillship TBN 2	Pride International	SHI	Samsung	675
Saipem 12000	Saipem		Samsung	660
West Gemini	Seadrill Ltd.	SHI	Samsung	598
Discoverer Inspiration	Transocean	Enhanced Enterprise	Daewoo	—
Transocean Drillship TBN 4	Transocean	Enhanced Enterprise	Daewoo	640
GSF TBN 1	GlobalSantaFe Corp.	Enhanced Global Marine Marine Glomar 456	Hyundai Heavy Industries Ltd. (HHI). Ulsan, South Korea	740
Total: 19 ships				**7,482 for 12 of 19 newbuilds**

*Data from Rigzone, operator, shipyard, and contractor reports.

TENDER-ASSIST VESSELS UNDER CONSTRUCTION, SEPTEMBER 2007*

Table 4

Rig Name	Manager	Water depth, ft	Yard, location	Delivery date	Cost, $ million
TAD-1	Saipem SPA	450	Boscongo Pointe Noire yard, Congo	2007	—
T-11	Seadrill Ltd.	6,500	Malaysia Marine & Heavy Engineering (MMHE) yard, Malaysia	2008	90
Seadrill 3600E semi-tender TBN	Seadrill Asia Ltd.	6,500	Keppel FELS, Singapore	2010	180
Total: 3 rigs					

*Data from Rigzone, operator, shipyard, and contractor reports.

tion yard in Altamira, Tamaulipas state, Mexico, with direct, deepwater access to the Gulf of Mexico.

Merging

Two Houston-based offshore drilling contractors, Transocean Inc. and GlobalSantaFe Corp., announced a merger in August (OGJ, Aug. 27, 2007, p. 30). Transocean's fleet includes 3 inland barges, 25 jack ups, 41 semisubs, and 16 drillships (including 4 under construction). GlobalSantaFe Corp. runs 60 rigs, including 43 jack ups, 14 semisubs (1 under construction), and 3 drillships (1 under construction). The merged company, to be called Transocean Inc., will control a global fleet of 147 rigs and valued at $53 billion.

Selling

In August, drilling contractor Pride International announced it was selling its fleet of three self-erecting, tender-assist rigs to Norway's Ferncliff TIH AS for $213 million. The sale is to close in January 2008. Abbot Group's subsidiary, international drilling contractor KCA Deutag, will manage and market the three tenders. Abbot Group has an option to take a 9.99% interest in the three rigs.

Pride had previously sold its two Latin American business units to GP Investments Ltd., an equity firm, for $1 billion (OGJ Online, Aug. 10, 2007). The sale includes Pride's Latin American land-based drilling and workover business unit, with 73 land drilling rigs, 135 workover rigs, and two lake drilling barges; and Pride's E&P Services division.

Pride will probably reinvest in long-term assets. Raymond James Energy analysts J. Marshall Adkins and James M. Rollyson said that Pride is likely to use proceeds from both deals to finance two drillships under construction, acquire newbuild spec rigs, or exercise its option to build another drillship. ✦

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New plays, prospects, resources continue to emerge

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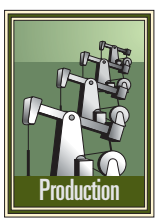


The last few years have witnessed the emergence of numerous unconventional gas plays and prospects in the US.

The industry continues to develop the extensive Barnett, Woodford, and Fayetteville gas shale resources and has expanded its search for new gas shale plays to West Texas, Alabama, Appalachia, and the Rocky Mountains.

Coals provide expanded opportunities for additional gas production even though the industry has delineated the easier to developed coalbed methane resources.

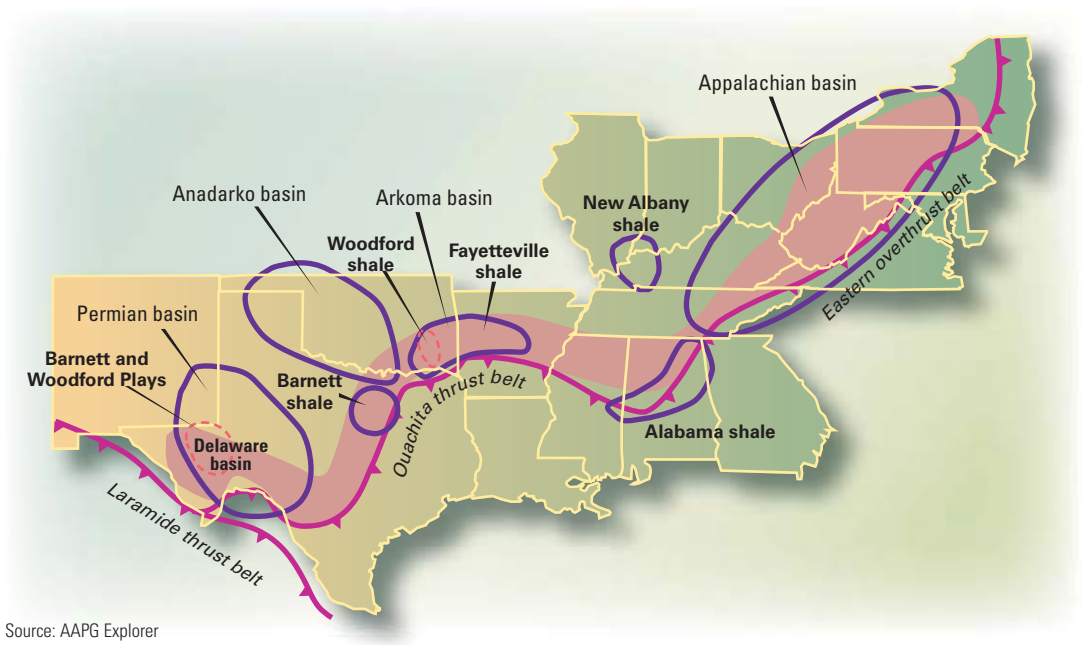
Aggressive development also continues in establishing new tight gas sand plays as well as revitalizing previous tight gas sand discoveries.

This article, the third in the series, describes many of these plays and prospects. The first part of this series was in OGJ, Sept. 3, 2007, p. 35, with the second part in OGJ, Sept. 17, 2007, p. 64.

UNCONVENTIONAL GAS—3

US GAS SHALE PLAYS

Fig. 1



Source: AAPG Explorer

Domestic gas outlook

The outlook for US natural gas production rests greatly on how successful industry is in finding and aggressively developing new and emerging unconventional gas resources. Opinions differ, however, on the likelihood of establishing new, large unconventional gas plays and prospects.

One view for future domestic natural gas production is that the outlook is perilous: "It is unlikely that a new onshore gas play, either conventional or unconventional, will be discovered in the US or Canada that will provide significant new supplies.... This is a perilous situation because the most prolific of these resources, including the Barnett shale, are already in relatively mature stages of development."[1]

The contrary view, supported by numerous industry

examples, is that the outlook is promising, assuming a renaissance in unconventional gas technology research, investment, and progress.

This article summarizes and provides examples of new supplies and emerging resources of unconventional gas. These resources seem substantial enough to fill a significant portion of the supply gap resulting from declining US conventional natural gas production.

Several of these new plays and prospect may not prove out, while others, with the aid of advances in unconventional gas technology, will likely emerge as sizable productive plays.

In addition, it is important to recognize that the already discovered plays provide opportunities for more intense development of these sizable unconventional gas resources.

Gas shales

Gas shales currently represent the most highly visible unconventional gas resource (Fig. 1). Such plays as the Barnett, Woodford, and Fayetteville shales are the most active, although several other shales show potential.

Combining innovative drilling and stimulation technology with a large resource potential has allowed the Barnett shale of the Fort Worth basin to produce 2 bcfd—sparking the current interest in evaluating and pursuing gas shales, a resource until recently categorized as a reservoir source rock or seal.

Two emerging gas-shale plays, the Fayetteville and the Woodford shales, have also reached high levels of production. For example, as of July 28, 2007, Southwestern Energy Co., the primary producer in the Fayetteville play, has increased its production from the play to 200 MMcfd from 50 MMcfd in 1 year (Fig. 2) and collapsed the initial "learning time" for this play to 2 years (Fig. 3).

Southwestern believes the Fayetteville shale has a potential 8,000 drilling locations and 11 tcf of recoverable resource.

Newfield Exploration Co., the primary producer in the Woodford shale, estimates that the play potentially has 3-6 tcf of recoverable gas. With new techniques such as long horizontal wells and advanced slick-water fracturing, producers have made plays such as the Woodford and Fayetteville shales economically productive.

Still, much remains to be learned about the favorable and less favorable geologic settings for these plays as well as the optimum drilling and completion practices.[2]

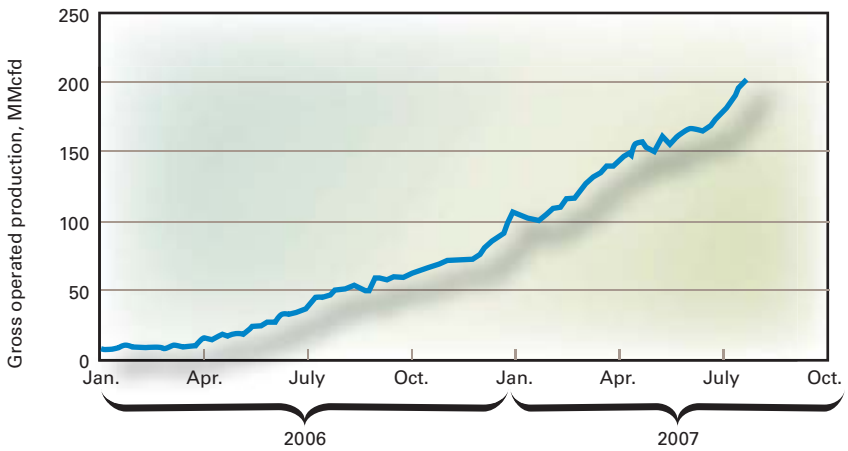
The search now is on for the next Barnett, Fayetteville, or Woodford shale play in places such as:

- West Texas for Barnett and Woodford shales.
- Alabama for the Conasauga shale.
- Appalachia for Marcellus and other gas shales.
- Rockies for numerous shale deposits.

The Barnett and Woodford shales in the Permian basin of West Texas are thicker and generally deeper than their Midcontinent counterparts. The Barnett shale has a 200-800 ft thickness at 5,000-15,000 ft depths, while the Woodford shale reaches a 400-ft thickness in the heart of the play. These shales have a high estimated organic content of 4-7% total organic carbon

SOUTHWESTERN ENERGY FAYETTEVILLE SHALE

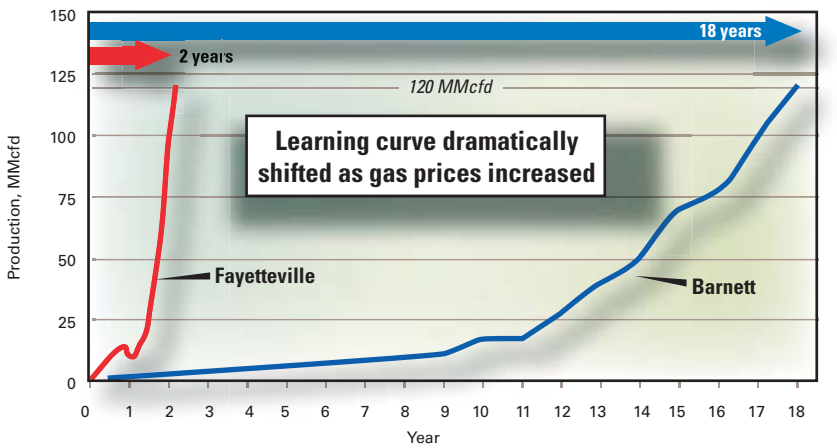
Fig. 2



Source: Southwestern Energy, data as of July 28, 2007

FAYETTEVILLE, BARNETT GROWTH COMPARISON

Fig. 3



Source: Pickering Energy Partners

(TOC), providing gas-in-place estimates of several hundred billion cu feet per square mile in favorable areas.[3]

The major unresolved issues are:

- Do these shales have sufficient permeability?
- Can they be effectively stimulated?
- Will wells be sufficiently productive to cover the high drilling and completion costs of $3 million for a vertical well and $4.5 million for a horizontal well?

As of the beginning of 2006, companies had leased more than 1.3 million acres in these two shale plays. Leased acreage is concentrated in Reeves and Culberson counties, with the deeper and thicker shales occurring in the central and western parts of Reeves County.

Conoco-Phillips, Chesapeake Energy Corp., and Encana Corp. currently hold large portions of the leased acreage, although it was the small independent, Alpine Inc. (operating as K2X in Texas), that took the risk to establish the productivity of these West Texas shales.[4]

But more test well results still are needed to verify that the industry can exploit economically the large gas-in-place in the West Texas Barnett and Woodford shales.

Leasing and drilling for the middle Cambrian-age Conasauga shale is underway in St. Clair and Etowah counties in northeastern Alabama. The Conasauga shale is several thousand feet thick (gross) due to the highly folded and faulted productive play area, potentially making it difficult to develop.

In February 2007, the Alabama State Oil and Gas Board established 25,000 acres in northern St. Clair County as a new gas-shale field named Big Canoe Creek. Dominion Black Warrior Inc. with 13 wells (each with relatively modest test rates) is the primary developer in this field.

Energen Resources Corp. has drilled three wells just outside the field boundary. It is still too early to determine whether this play will be a major gas shale play or an economic disappointment.[5,6]

The Devonian-age Marcellus shale in eastern Pennsylvania and New York typically lies at 5,000-8,000 ft and has 75-200 ft of net pay. The shales are organically rich and thermally mature with nearly 5% TOC and average vitrinite reflectance values (R_o) of 1-2%.

Range Resources Ltd. has drilled 27 wells in the Marcellus shale and expects 0.8 bcf/well estimated ultimate recoveries (EURs) from its initial wells. Range is experimenting with Barnett-like horizontal wells and slick-water fractures that, while more expensive, are expected to increase productivity greatly.

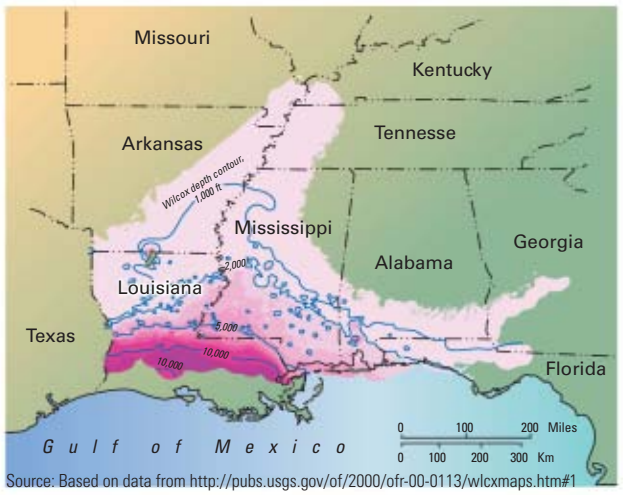
Within its 500,000-acres of Marcellus shale leases, Range projects an unrisked 2.5-5 tcf resource potential.[7-9]

The gas basins in the Rockies have numerous Cretaceous and late Carboniferous-age shales. With the growing interest in gas shales, it seems that exploration is taking place in every basin with a feasible shale resource. In line with its "early-mover" reputation, Bill Barrett Corp. has initiated its Yellow Jacket shale-gas project in southern Colorado and Utah, targeting the Pennsylvanian Gothic shale between 5,500 and 7,500 ft. Barrett estimates 800 bcfe of unrisked potential on its 63,000 (net) acre lease, expecting 1-3 bcf/well EURs.

Numerous producers also are exploring the potential of the Cretaceous-age Baxter shales in the Green River basin. Questar Corp. has drilled or recompleted 18 wells in the Baxter and plans to drill 10 more in 2007, at depths ranging from 10,000 to 13,500 ft. One planned well includes a horizontal

GULF COAST TERTIARY COAL BELT

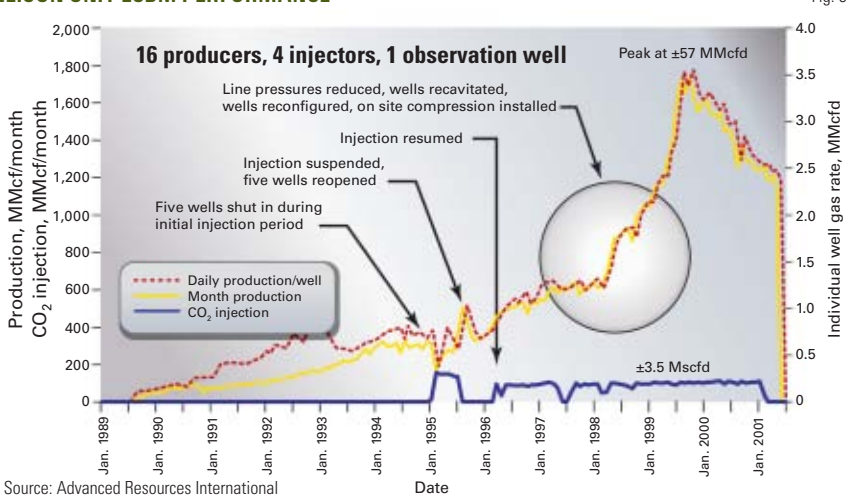
Fig. 4



Source: Based on data from http://pubs.usgs.gov/of/2000/ofr-00-0113/wlcxmaps.htm#1

ALLISON UNIT ECBM PERFORMANCE

Fig. 5



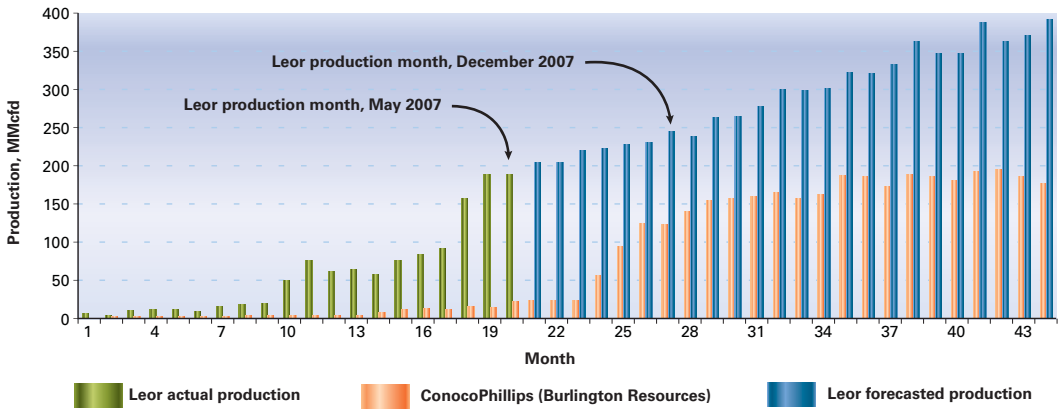
Source: Advanced Resources International

completion.

Kodiak Oil and Gas Corp.'s NT Federal No. 1-33 Baxter shale well tested 2 MMcfd of gas plus considerable water. The company completed this $4.5 million well with a nine-stage frac. Kodiak has plans to drill five more wells near the NT Federal well.

DEEP BOSSIER PRODUCTION

Fig. 6



Source: Data from Texas Railroad Commission web site, May 2007. Note data may be incomplete or inaccurate for recent months.

Coalbed methane

Much of the higher quality, easier to produce coalbed methane resource plays has been found. What remains are the deeper coals, the lower rank coals and the opportunity to develop existing plays more intensively. Notable potential plays are:

- Deep coals of the Greater Green River and Piceance basins, estimated to hold hundreds of tcf of gas in-place.
- Lower rank, Tertiary-age coals along the Gulf Coast.
- Additional development of the already discovered Raton, San Juan, and Uinta basin coals with infill wells, restimulation, and enhanced coalbed methane (ECBM).

The coalbed methane in the Green River and Piceance basins has long been noted for two things: the vast in-place resource and their considerable depth. Estimates put the in-place coalbed methane resource of the Green River basin at 314 tcf[10] and of the Piceance basin at 84 tcf.[11]

In the Piceance basin, the Cameo coal in the Paludal zone below the Williams Fork (Mesaverde) tight gas sands contains about 80% of the basin's CBM resource.

During the 1980s and early 1990s, producers experimented with commingling production from these deep tight gas sands and coals, motivated, in part, by Section 29 tax credits. The high reservoir pressure, however, and the increase in water production from completing the coals eventually discouraged this practice.

More recently, Encana has reported completing the entire Williams Fork (Mesaverde) interval, including the lower Paludal coal zone, with vertical wells and multiple fracs.

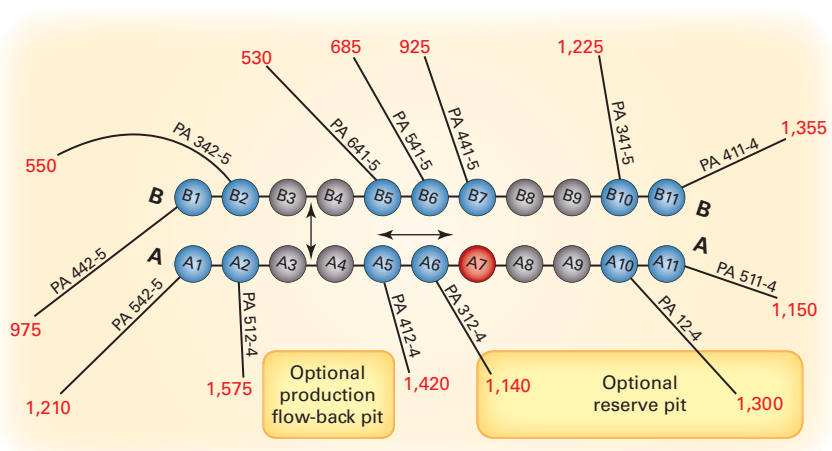
In the Green River basin, 85% of the 314-tcf coalbed methane resource occurs below 6,000 ft. Since the early 1990s, operators have attempted to tap into these deep coals through completions into multiple seams or through commingled completions of coals and overlying Mesaverde tight gas sands, all with limited success. Today, drilling for these coals is under way in the Atlantic and Pacific Rim projects, along the shallower flanks of the Washakie basin.

At the Atlantic Rim project, Double Eagle Petroleum Co. has been the most active producer with about 165 wells drilled and with 120 wells planned for 2007. Estimated recoveries are 1.0-1.2 bcf/well, with drilling and completion costs of $1 million/well.

Pending final approval of an environmental impact study (EIS) filed for the Atlantic Rim, operators estimate that

WILLIAMS, PICEANCE BASIN WELL PAD

Fig. 7



Source: Williams

PINEDALE, LANCE-MESAVERDE WELL COMPLETION ADVANCES

Table 1

Year	No. of wells	Average number of perforations/ stimulation	Average proppants/ stimulation, lb	Average gross interval, ft	Average production, first 12 months, MMcf
2000	3	5/5	275,000	2,400	0.6
2004	83	20/20	175,000	4,500	1.1
2006	161	40/15	100,000	5,000	1.0

1,800 wells may be drilled in the next 5 years. While the active drilling in the shallow Green River coals is encouraging, the ultimate fate of the CBM potential in the Green River basin lies in the still to be explored deep coals.

A large in-place coalbed methane resource also exists in Gulf Coast Tertiary coals, stretching from the Florida panhandle to the Texas Gulf Coast (Fig. 4). One study[12] sets the in-place resource at 4-8 tcf, while an independent mapping and resource assessment puts the size of the in-place resource much higher, with 3.4 tcf possibly recoverable.[13]

Prospective coals occur at 1,500-5,000 ft depths with more mature, gas-rich coals below 3,000 ft. Drilling has been limited to individual test pilots and significant production has yet to be established. Leasing, however, has been active, with more than 400,000 acres leased to date.

BP PLC's Tiffany (N_2) and Burlington Resources Inc.'s Allison (CO_2) San Juan basin ECBM pilots, conducted in the early 2000s, demonstrated the potential for ECBM to boost production. At the Allison test, involving 16 production wells and 4 CO_2 injection wells, gas production increased five-fold to a peak of about 3.5 MMcfd/well after CO_2 injection from about 700 Mcfd/well before CO_2 injection (Fig. 5). The pilot, however, had numerous other well enhancements and ECBM may only account for about one-third of the increase.

Consistent with laboratory work, the ECBM test also experienced a loss in CO_2 injection capacity. The loss of injection capacity, however, was modest at 50% and appeared to improve over time. The authors believe that ECBM will likely remain a lower priority until the US enacts carbon credits for storing anthropogenic CO_2. Work by ARI indicates that US coalbeds could ultimately sequester 90 gigatons of CO_2.[14]

To understand this resource better, the US Department of Energy is sponsoring a series of field tests involving CO_2-ECBM and CO_2 sequestration.

Tight gas sand

With the benefits of expanding geological knowledge, improved well-completion technology, and a willingness to take risks, industry continues to find and establish new tight gas sand plays as well as revitalize previously discovered plays.

Notable growing tight gas sand plays are:

- Lance at Pinedale in southwestern Wyoming.
- Deep Bossier in East Texas.
- Mesaverde in the Piceance and Uinta basins.

All three of these unconventional-gas plays offer promise for intensive resource development.[15]

Gas production has climbed rapidly for the Lance-Mesaverde tight-gas play, now approaching 1 bcfd. The Lance-Mesaverde reservoirs contain stacks of channel-fill sandstones, involving 20-70 individual sand packages and providing net pay of 300 to more than 1,000 ft.

Three-dimensional seismic is helping identify fairways in these complex stacked reservoirs and advanced core and log analysis is providing a more complete geologic model of the productive sands in the field.

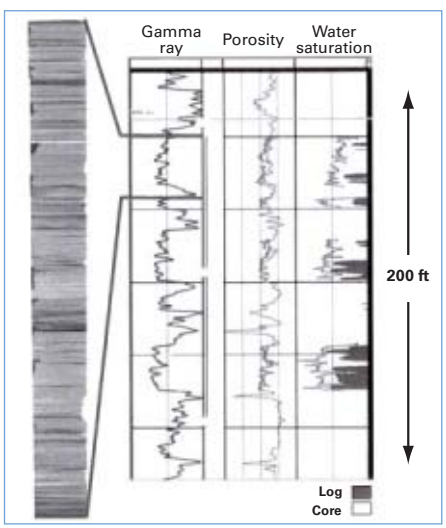
Operators have determined that a greater number, a dozen or more, of smaller-size (about 100,000 lb of proppant) stimulations help a well achieve contact with more sands than the previous smaller number of larger-size stimulations (Table 1).

The low-permeability of the Lance-Mesaverde sands and their lenticular nature allow considerable downspacing for wells without significant loss in well productivity. For example, Ultra Petroleum Corp. conducted a study on 170 Pinedale wells spaced at 10 acres. The study noted little to no well interference and opened up the potential for closer, more optimal well spacing for this tight gas sand play.

Estimated well EURs continue to increase, rising to nearly 9 bcf/well for more recent completions from less than 5 bcf/well in the late 1990s (Table 2).

EOG UINTA BASIN PAY ASSESSMENT

Fig. 8



	Net pay, ft	Porosity, %	Water saturation, %	Gas in place, bcf/section
Openhole log	41	9.3	55	42
900-ft oil-based core	216	8.6	45	250

Source: EOG Resources

Ultra, the largest leaseholder on the Pinedale anticline, has drilled and placed on production 168 wells. With more than 5,000 drilling locations, Ultra believes its holding may contain 23 tcf of ultimate gas recovery (gross).

Shell Exploration & Production Co., with 82 bcf of Pinedale production last year, has participated in drilling more than 260 wells. Shell is pursuing increased efficiency in well completions, with up to 8 frac stages/day/well reported recently. Shell has also undertaken individual reservoir sand-unit pressure tests to determine sand continuity and optimal well spacing.

Questar Corp., with 195 producing wells, believes that, with down-spacing, it still has more than 900 undrilled locations within its core acreage.

The Lance-Mesaverde tight gas sands at Pinedale field have already produced more than 1 tcf of gas to date. With all three major operators reporting increased drilling in 2007, Pinedale is poised to become Wyoming's largest producing natural gas field and one of the largest in the US.

The Deep Bossier is a high pressure, high-temperature tight gas sand reservoir, occurring at depths generally greater than 15,000 ft. It is a Jurassic-age continental slope depositional system on the western flank of the East Texas basin. The resource is characterized as containing thin, overpressurized, low-water saturation, low-permeability sands within a thick package of marine shales.

The overall shale-sand package ranges in thickness from 1,000 to 2,500 ft, with 25 to 100 ft of net sand. Pressure gradients range from 0.6 to 0.8 psi/ft and matrix permeabilities are on the order of 5 µd. Wells in this difficult, deep play currently cost between $8 million at 15,000 ft and $12 million at 18,500 ft to drill and complete. It is anticipated, however, that well costs will come down as drilling practices evolve. While operators typically report EURs from 5 to 7 bcf/well, a handful of wells have EURs in excess of 20 bcf.

Three main operators are developing this emerging tight gas sand play. Gastar Exploration Ltd.'s primary asset is the Hilltop Resort field in which it holds 16,350 net acres. Gastar has drilled 16 Deep Bossier wells in the field and estimates a recoverable resource of 350 bcfe within its lease acreage.

EnCana and Leor Energy LP have joint working interest in the 190,000-acre Amoruso field. The companies estimate that their acreage holds multiple tcf of recoverable gas. The field currently produces about 200 MMcfd and may reach 350 MMcfd by yearend 2008 (Fig. 6). Encana and Leor have drilled some exceptional wells in the Amoruso field, including three that produced more than 1 bcf in their first 30 days.

ConocoPhillips is active in the Savell and Rainbolt Ranch fields where the company holds about 200,000 acres, produces about 200 MMcfd, and has plans to increase drilling this year. Gas production rates from the wells in these two fields are impressive (Table 3).

The Deep Bossier play is still in early exploitation. If the Savell, Hilltop Resort, Amorusa, and Rainbolt Ranch fields continue their success, the Deep Bossier has the potential to become one of the larger domestic tight gas sand plays with production of 1 bcfd or more.

The Williams Fork-Mesaverde play in the Piceance basin is a growing Rockies tight gas sand play that produced 145 bcf of gas in 2006. A geologically analogous tight gas play in the Uinta basin, the Wasatch-Mesaverde, is still in early development. These are stacked, lenticular sand plays deposited in fluvial and coastal environments. The reservoirs consist of a 3,000-4,000 ft thick package of sands, shales, and coals, with a series of 20-40 ft thick point bar sand deposits that terminate abruptly at low-permeability boundaries.

The Piceance basin Williams Fork (Mesaverde) play has seen significant innovations during its development. For example, Williams Co., the dominant producer in the play, is using FlexRigs that are capable of drilling up to 22 wells from a single pad (Fig. 7). It reports drilling times of fewer than 10 days/well with this rig, compared with 20 days to drill a well 5 years ago.

The company also has centralized well-fracturing operations, with up to 65 wells on 6 pads fractured from a single location.

Williams also is actively pursuing the largely undeveloped Piceance Highlands properties holding 3,700 undeveloped drilling locations and 3 tcf of potential resource.

The Uinta basin portion of the Wasatch-Mesaverde tight gas sand play is still in the process of being defined. EOG Resources Inc. has conducted coring studies that point to more than 200 ft of pay in a 900 ft interval vs. only 40 ft previously identified by openhole logs.

EOG now estimates that the play contains up to 250 bcf/section of gas in-place, five times higher than estimated from logs (Fig. 8).

Completion and treatment of as

PINEDALE, LANCE-MESAVERDE TIGHT GAS SAND WELL PERFORMANCE

Table 2

	Total wells	Successful wells	EUR/well, bcf	Success rate, %
1996-99	9	9	4.6	100
2000-02	48	47	8.6	98
2003-05	222	217	8.7	98

Note: EUR—Estimated ultimate recovery.

SELECTED SAVELL FIELD DEEP BOSSIER WELLS

Table 3

Year	No. of wells	Cumulative recovery through Mar. 2007, bcf	Average peak month rate, MMcfd
2004	2	24.4	19.8
2005	10	76.0	17.9
2006	7	0.03	14.8

much of the sand in the Wasatch-Mesaverde interval as possible is a key technology step. For example, Bill Barrett Corp. has been stimulating an average of 10 multipay zones across an interval of about 2,900 ft in their Peters Point field wells. Its average well has produced 0.9 bcf in the first 12 months.

Within their Uinta acreage, Bill Barrett has identified 250-300 drilling sweet spots where it expects the multiple-pay-zone stimulation practices to provide EURs of 2-3 bcf/well, much higher than achieved by earlier wells in this area.

Next steps

Space constrains this review and discussion of new and emerging unconventional gas plays. Numerous other potential opportunities exist, such as the tight gas sands of the Columbia basin, the coalbeds of the Midcontinent, and the gas shales of Alberta and British Columbia.

An important next step is a renewed emphasis on rigorously establishing the resource-in-place for unconventional gas.

Early visionary steps to quantify the gas in-place in tight gas sand plays were taken by USGS scientists (Law, Spencer, Fouch, and Johnson, among others) using the best of limited and difficult-to-interpret data. The database is now considerably larger and today's log-and-core interpretation methods are superior.

ARI's decades of work on unconventional gas resources convinces us that large volumes of unconventional gas resource remain. With technology, vision, and persistence, these could be converted to recoverable reserves, but much still remains to be learned about the true size and nature of the unconventional gas resource and its economically prospective plays.

Acknowledgment

The authors thank Peggy Williams for her personal correspondence regarding the shale section of this article. ✦

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Vello A. Kuuskraa's photo and biographical information appeared in Part 1 of this series (OGJ, Sept. 3, 2007, p. 35).

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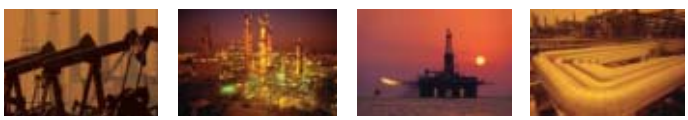

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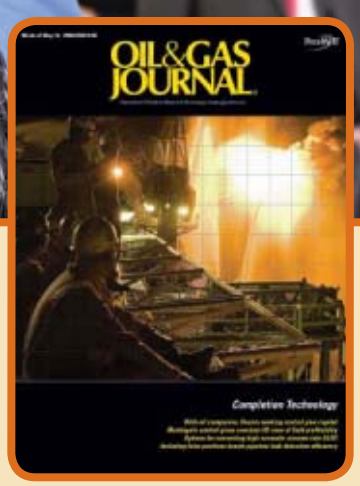

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Low-cost revamp strategies improve FCCU performance

Sriganesh Gandham
Divya Jain
Hindustan Petroleum Corp. Ltd.
Mumbai, India

Hindustan Petroleum Corp. Ltd. (HPCL) used low-cost modifications to the FCC unit in its Mumbai, India, refinery to improve performance. The low-cost revamp, which cost about $2 million, generated $0.2/bbl in savings with a payback of 5 months.

The FCC is the primary source of gasoline and LPG production in many Indian refineries. Increasing unit capacity and improving yield and product quality have a dramatic effect on refinery economics and the FCC's ability to help meet new product specifications.

The FCC process has complex interactions between feed, catalyst, and hardware. Identifying the hardware constraints in FCCUs and unlocking their potential using simple and low-cost modifications enhance cracker capacity and yields.

The FCC unit at HPCL's Mumbai refinery has a 20,000 b/sd, side-by-side reactor-regenerator. The key constraints were catalyst circulation, reactor stripper head, orifice chamber, wet gas compressor, and downstream facilities.

The 2005 revamp involved stripper internal modifications with an elevated bed, catalyst transfer-line aeration changes, a redesign of the orifice chamber, modifications in the regenerator air grid, changes in fractionator internals, and the installation of a high-efficiency rotor bundle. These modifications, which required little investment, have unlocked the FCC's potential by improving its throughput and yields.

Background

HPCL's original FCCU with bed cracking was commissioned in 1955. The unit was revamped in 1999 to modernize the facility and to increase the feed rate to 20,000 b/sd from 10,000 b/sd.

The original FCC licensor conducted the basic engineering design for the revamp (reactor, regenerator, transfer lines, etc). The revamp design included some of the licensor's new technologies, such as new high-pressure-drop feed injectors, new catalyst transfer lines, extended feed riser terminating at cyclone inlet elevation, etc.

The revamp design was, however, constrained because the existing unit was to be modified while maintaining the basic vessel layout, structure, and foundation. The refiner designed the downstream sections including the waste-heat boiler, stack valves, orifice chamber, cat fractionator, and gas concentration unit (GCU) section.

The modernized FCC had advantages compared with the earlier bed-cracking unit:

- High temperature regeneration (690-720° C. vs. 600° C.) led to less carbon on the regenerated catalyst.
- Riser and transfer-line cracking vs. dense bed cracking improved product selectivities.
- A cold-wall reactor design improved mechanical reliability.
- Advanced high-pressure drop

FCC YIELDS, OPERATING CONDITIONS Table 1

	Design	Actual, 2004
Throughput, 1,000 b/sd	20	20
Yields, wt % on fresh feed		
Dry gas	1.8	2.4
LPG	16.5	12.5
Light cracked naphtha	38.5	30.0
Light cycle gas oil	31.5	36.5
Resid	8.2	15.0
Coke	3.5	3.5
Operating conditions		
Reactor temperature, °C.	510	490-495
Reactor-regenerator differential pressure, psi	3.0	4.5
Catalyst/oil ratio	3.8	3.3

Based on a presentation to the 2007 National Petrochemical & Refiners Association Annual Meeting, San Antonio, Mar. 18-20, 2007.

feed injectors vs. open pipe injectors gave a better yield pattern.

The changeover from the existing bed cracking to a new FCC design improved process unit yields substantially. Because the actual feed quality was quite different from the design feed, however, the resulting yields were different due to changed operating conditions. Subsequently, HPCL and the FCC licensor worked together to analyze and resolve the limitations, which helped to improve the unit operation substantially.

Table 1 shows unit performance in 2004 vs. design conditions. There was still a gap between the design and actual yields and we felt we could improve unit performance. Unit constraints in 2004 were:

- Suboptimal catalyst circulation resulting in low catalyst-oil ratios and high heater outlet temperatures that led to undesirable production of gas and coke.
- Limitations in regenerator air plate grid and the flue gas stack valves and orifice chamber.
- Limitation in the desuperheating section in the main fractionator.
- Wet gas compressor capacity.
- GCU capacity and product quality.

Problem identification

For a pressure-balanced unit, such as the one at Mumbai, catalyst circulation rate is controlled and adjusted with changes to the spent-catalyst circuit. The primary control variables are unit differential pressure, stripper level, and control air rate (to a lesser extent).

The regenerated-catalyst circuit then responds to these changes by adjusting the overflow-standpipe catalyst level to maintain the catalyst circulation-rate constant between the two vessels. Table 2 shows the three spent catalyst-circuit control parameters that increase catalyst circulation.

Once the catalyst level approaches the top of the overflow standpipe in the regenerator, the FCC becomes nonresponsive to additional changes in the spent-catalyst circuit and no further increases in catalyst circulation rate are possible. Typically, the stripper level will decrease because the amount of catalyst returned to the reactor is less than that transferred to the regenerator. Optimization of both transfer-line circuits is therefore necessary to achieve maximum catalyst circulation.

Table 3 shows the results of a detailed pressure survey that compares the design and actual pressure profile. The survey showed these limitations:

- Pressure buildup in the reactor stripper was lower than design.
- Pressure drop in spent-catalyst transfer line was higher than design.
- Pressure buildup in regenerator standpipe was high. Due to low catalyst density in standpipe (20 lb/cu ft), however, the standpipe was essentially full with catalyst to the top of the overflow standpipe.
- Pressure drop in the regenerated-catalyst transfer line was higher than design.

In 2005, to improve unit performance in the constrained areas, we modified the reactor stripper, orifice chamber, air grid, wet gas compressor, main fractionator, GCU, and catalyst formulations.

Stripper modifications

To increase catalyst circulation, we raised the pressure in the spent-catalyst circuit by raising the catalyst level in the stripper. With a reactor stripper level of 70%, pressure at the bottom of spent-catalyst circuit was about 4.2 psi. This was just enough to overcome the pressure drop in the catalyst transfer lines and spent-catalyst riser for a circulation rate of 7.0 tonnes/min.

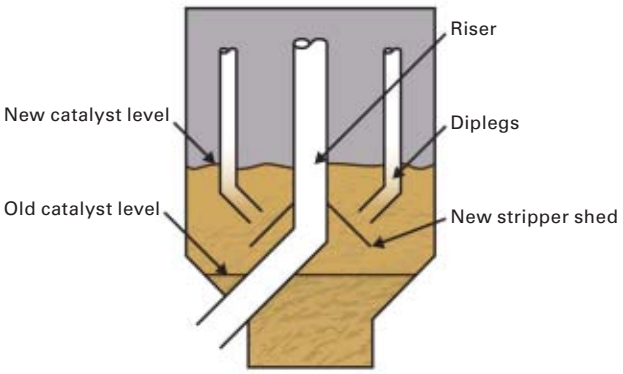
Increasing circulation to design level of 9.3 tonnes/min required a pressure of 6.0 psi in the reactor. To achieve this, we proposed increasing the catalyst height in stripper by 3 m.

To avoid channeling of catalyst and stripping steam and defluidization of catalyst at the increased stripper height, we added a new stripper shed cone close to the new catalyst level. This cone was attached to the riser and had multiple holes at the periphery to allow for good steam and catalyst contact.

Fig. 1 depicts the new stripper shed attached to the reactor riser.

The increase in catalyst level caused the reactor diplegs to be submerged in the catalyst bed. We evaluated the effect of increased catalyst level on cyclone performance and determined that there was sufficient dipleg outage to satisfy the cyclone pressure balance. We therefore made no changes to the cyclones.

NEW STRIPPER SHED Fig. 1

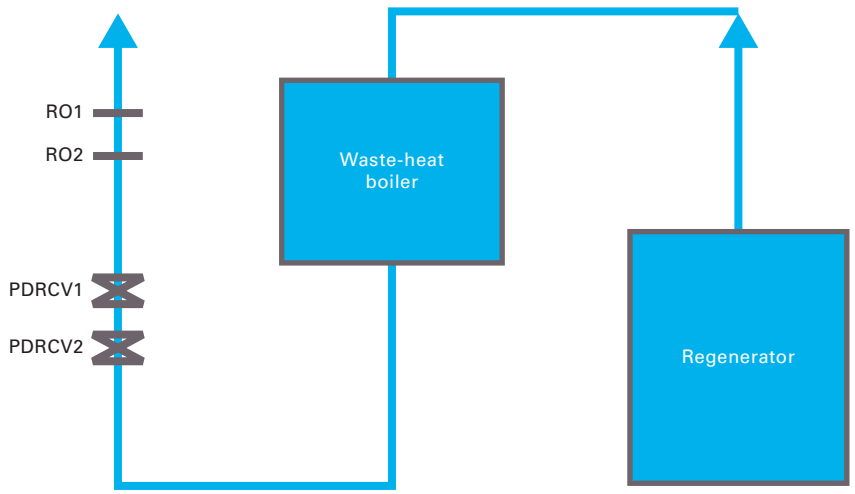


SPENT CATALYST CIRCUIT Table 2

Control parameter	Process change	Mechanism
Differential pressure (Reactor-regenerator)	Increase delta P (i.e., decrease regenerator pressure)	Reduces resistance to catalyst flow from reactor to regenerator
Stripper level	Increase catalyst level	Provides more driving force for catalyst flow from reactor to regenerator
Control air rate	Increase air rate	Decreases control air riser density and decreases resistance to catalyst flow

REGENERATOR FLUE GAS PRESSURE CONTROL

Fig. 2



Standpipe catalyst density

During earlier pressure surveys of the regenerator standpipe, the catalyst density was very low at 20-22 lb/cu ft. This was comparable to a regenerator bed density of 18-20 lb/cu ft.

Aeration along the regen standpipe is one of the hardest things to control in an FCCU because overaeration and underaeration can lead to low-pressure buildup in the standpipe and, ultimately, limit catalyst circulation. If the standpipe is underaerated, the pressure buildup will be low and frictional losses will be high. Conversely, if the pipe is overaerated, bubbles will form that will restrict catalyst flow.

The volume of aeration required along the length of pipe depends on the catalyst properties, standpipe conditions, distance between the aeration points, and catalyst circulation rate. In practice, however, the field transfer line's pressure surveys indicated an inconsistent pressure profile. We rectified this in gradual steps by changing the aeration pattern. This improved the catalyst circulation from the regenerator to the reactor.

Changing the aeration pattern and increasing the pressure in the stripper improved overall catalyst circulation rate and stability.

Orifice chamber

One of the tools for an operator to control catalyst circulation in a pressure-balanced unit is the pressure differential between the reactor and regenerator. Reactor pressure is usually fixed based on fractionator pressure and the regenerator pressure is varied to increase or decrease catalyst circulation.

Two sets of double-disc stack valves, also called pressure differential control valves (PDRCVs), control the regenerator pressure.

Flue gases exiting the regenerator at 730-740° C. cool to 220° C. by generating medium-pressure steam in a waste-heat boiler located in the flue gas line. Cooled flue gas then flows through the two PDRCVs and then two fixed-restriction orifice plates (RO1 and RO2) before discharging through the stack to the atmosphere.

Fig. 2 shows the flow of regenerator flue gas.

Well-operating PDRCVs are necessary for having fine pressure control between the reactor and regenerator and, therefore, steady catalyst circulation and reactor temperature. Since initial unit commissioning, the PDRCVs only opened 1-2%. To keep them in a controllable range, the airflow rate to regenerator was kept higher than was required; this led to high catalyst losses.

Small PDRCV openings indicated that the fixed orifice plates had a small pressure drop and almost the entire system's pressure drop (90%) occurred across the PDRCVs. This was affecting unit stability because the catalyst circulation rate was erratic and led to swings of 8-10° C. in the reactor temperature.

We therefore redesigned the orifice plate's assembly to take a 75:25 pressure drop across the orifice plates vs. PDRCVs. The existing two-plate orifice assembly was replaced with a three-plate assembly. Each orifice plate was designed with a greater pressure drop vs. the earlier operation.

We increased the orifice plate's thickness to be consistent with a maximum design pressure drop of 12 psi. A total of 30 holes were provided in each plate with 22, 26, and 29 open holes, respectively.

Table 4 shows the pressure profile with the two- and three-orifice-plate systems.

The revised pressure profile increased the PDRCV opening to 15-20%, which led to these advantages:

- Better unit stability. The catalyst's circulation rate is steadier and reactor temperature swings reduced to 1-3° C.
- Reduced airflow to regenerator air grid. When the pressure drop across the orifice plates increased and the PDRCVs opened, airflow was lowered closer to the theoretical requirement. This reduced catalyst losses substantially, to 1.3 tonnes/day from 2.5 tonnes/day.

Afterburning, air grid

The new FCC, commissioned in 1999, was originally designed to operate in partial-burn combustion mode with a CO concentration of 6 mole %. Due to a big difference between the design and actual feed-quality basis, however, the FCC currently operates in full-combustion regeneration mode (excess flue gas oxygen).

Generally, for a full-burn regenerator, operating the dense bed at more than 700° C. and maintaining the flue-gas excess oxygen content at 1-2% can minimize afterburning. This ensures that sufficient oxygen is available to

complete combustion in the dense bed.

At oxygen levels of less than 1%, the unit will potentially operate in the full burn-partial burn transition regime, resulting in afterburning. Refiners must avoid this transition regime by closely monitoring the flue-gas analysis.

Although the use of CO promoter can be effective in controlling afterburning, we still experienced severe afterburning, which indicated that it resulted from CO and oxygen breakthroughs from the dense bed.

When we mapped the regenerator's temperature profile, we observed that afterburning was more severe in the spent-catalyst riser section. The secondary cyclones' outlet temperatures on the spent-catalyst riser side were 50° C. higher than the cyclone outlet temperatures relative to the overflow well side.

The temperature profile indicated CO was breaking through from the spent-catalyst riser section and oxygen was breaking through from the overflow well section. Excess CO was combining with oxygen in the plenum section and across the cyclones, leading to severe afterburning.

We revised the regenerator grid hole pattern to have more grid holes in the spent-catalyst riser side to provide more oxygen. The final pattern increased the ratio of holes in spent-catalyst riser/overflow side to 60/40 vs. a typical design ratio of 55/45. This change reduced afterburning significantly.

The cyclone outlet temperatures in the regenerator plenum now closely match. Regenerator dense-bed temperatures near the spent-catalyst riser increased 10° C., which shows that there is better combustion on the spent-catalyst riser side.

We offset the main air blower capacity limitation expected with increased airflow to the regenerator air grid by increasing the number of air grid holes to 790 from 730. The pressure drop across the grid dropped to 2.2 psi from 2.7 psi; this lower backpressure to the air blower helped increase air to the regenerator by 2,000 scfm after the 2005 revamp.

Wet-gas compressor

The existing wet-gas compressor (WGC) was earlier revamped to produce a high polytropic head with a capacity of 21.5 tonnes/hr. The compressor spillback valve controls the fractionator pressure.

A study of the reactor-regenerator section indicated that with an increase in catalyst circulation to 9.0 tonnes/min, and with a new catalyst formulation, wet-gas generation can increase to 30 tonnes/hr from 21.5 tonnes/hr. A check of the WGC at 30 tonnes/hr indicated that both the compressor and the motor were limiting.

We took this approach to debottleneck the WGC:

- Reduce the number of impellers to lower the compressor's polytropic head. The current rotor bundle had six impellers and was developing 41,000 ft/lb_f of head, which could be reduced to capture the capacity enhancement.
- Increase the compressor's suction pressure. In the existing system, there was about 14 psi of pressure drop across the suction control valve to meet the suction pressure requirement of existing impeller. Increasing suction pressure raises the mass flow through the compressor, therefore increasing capacity and reducing the polytropic head.
- Replace the existing low-efficiency rotor bundle with a high-efficiency rotor bundle consisting of diaphragm, guide vanes, valves, and labyrinths. This can reduce internal leakages and compressor efficiency could increase to 79.5% from 66.5%.

New hardware developments enabled us to revamp the WGC with a five-stage rotor bundle. It avoided the need to procure a completely new compressor, which would have required substantial changes in the unit's structure and foundation, changes with associated inlet and outlet piping and accessories, and higher costs.

A lower polytropic head and greater compressor efficiency enabled the existing motor to handle more wet gases without any modifications.

Table 5 compares conditions before and after the revamp.

Main fractionator

Modifications in the reactor-regenerator and WGC created the potential to increase reactor outlet temperature and achieve 110% design feed rates. At the increased feed rate and reactor outlet

PRESSURE SURVEY

Table 3

Location	Pressure, psig — Design	Actual
Reactor top	31.0	26.4
Bottom of reactor stripper	37.1	30.6
End of spent catalyst transfer line	36.0	28.0
Regenerator top	28.0	22.0
Bottom of regenerator standpipe	34.0	30.5
End of regenerator catalyst transfer line	33.5	24.1

FCC PRESSURE PROFILE

Table 4

Location	Pressure, psig — 2 orifice plates	3 orifice plates
Regenerator	28.0	29.0
Upstream of PDRCV 1	26.1	26.6
Upstream of PDRCV 2	14.0	23.3
PDRCV average opening, %	2.0	18
Upstream of RO 1	2.6	20.1
Upstream of RO 2	1.2	14.3
Upstream of RO 3	–	6.5
Ratio of pressure differences across PDRCV vs. RO	90:10	25:75

CONDITIONS BEFORE, AFTER REVAMP

Table 5

	Before revamp	After revamp
Flow, tonnes/hr	21.5	31.5
Suction pressure, psig	6.8	16
Discharge pressure, psig	150	150
Polytropic head, 1,000 ft/lbf	41	36
Polytropic efficiency, %	66.5	79.5
Rotating speed, rpm	8,727	8,810
Motor power, hp	1,750	1,750

REVAMP YIELDS, THROUGHPUTS

Table 6

	Before revamp	After revamp	Postrevamp 110% design
Throughput, 1,000 b/sd	20	20	22
Yields, wt % on fresh feed			
Dry gas	2.5	3.0	2.6
LPG	12.5	17.5	16.0
Light cracked naphtha	30.0	38.0	35.0
Light cycle gas oil	36.5	28.0	30.0
Resid	15.0	10.0	13.0
Coke	3.5	3.5	3.4

temperature, vapor load in main fractionator shed section increased, along with pressure drop.

The option to replace shed trays with structured packing or changing the tray spacing was not possible due to time limitations. Two shed trays that had the maximum vapor load were therefore removed to create more curtain area for the vapors to pass through. Of eight shed trays, two were removed, which enabled better desuperheating without entrainment.

GCU

GCU operations were limiting the feed rate at 20,000 b/sd. This led to pressure swings in the stabilizer column, inconsistent product quality of LPG and light cracked naphtha (LCN), and liquid carryover from the de-ethanizer column overhead. A detailed internal study indicated flooding of the de-ethanizer and debutanizer.

To resolve these limitations, we revamped the existing two-tower GCU configuration (de-ethanizer and debutanizer) to a three-tower configuration to handle more LPG and LCN, and improve the rvp of the cracked naphtha.

The first tower in the existing configuration (de-ethanizer) tower was converted to a primary absorber tower. The debutanizer was converted to a stripper tower. A new tower with a greater diameter and height was installed as the new debutanizer.

To overcome the problem of water accumulation in the de-ethanizer tower, a water-settling drum was provided.

This revamp, which used as many existing assets as possible, enabled us to produce about 30% more LPG and LCN from the FCC. It also helped lower the rvp of the LCN to the desired specification of 8.7 psia.

Catalyst formulation

Fresh catalyst formulation plays a vital role in determining process-unit conversions and yields, along with other parameters such as catalyst/oil ratio, reactor outlet temperature, and feed quality. The loss in unit conversion due to low catalyst circulation rate or low reactor temperature can be made up substantially by increasing the catalyst activity.

Before the revamp, fresh-catalyst activity could not increase due to severe limitations in WGC. The WGC rotor bundle revamp removed the limitation of handling LPG and gas make from the unit. We selected fresh catalyst for the revamped unit to maximize conversion and yield that match the downstream equipment recovery and capacities:

- Fresh catalyst activity increased to 80 from 75 microactivity test.
- Zeolite/matrix ratio increased to 85% from 70% to raise the catalyst activity.
- Rare earth of the catalyst also increased to 1.5% from 0.5% to limit olefins in gasoline.

The new catalyst yielded significant increases in LPG and LCN yield and reduced bottoms yield.

Revamped unit performance

All the modifications were implemented during a turnaround in 2005. This resulted in increasing the yield pattern and also helped increase the feed rate to 110% of the design capacity. Table 6 shows the improvements in process unit yields.

LPG and LCN yields increased significantly. Bottoms yield also reduced substantially. The load to WGC increased to 28-29 tonnes/hr from 21.5 tonnes/hr. PDRCV operation improved with openings in the range of 15-25%. Reactor temperature swings have lowered to 1-2° C.

The successful Mumbai refinery revamp was coupled with a unit-specific catalyst formulation involving zeolite and matrix compositional changes, along with suitable additives.

The modifications made in stripper baffle, compressor rotor bundle, control valves, and piping increased the FCC potential by improving its throughput and yields. These low-cost solutions that cost $2 million, helped boost FCC performance by generating $0.2/bbl with a payback of 5 months. ✦

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New methods ease multiline stray-current measurement

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Increasingly complex matrices of potential stray-current corrosion sources have made mitigation of potential problems both more difficult and more important.

New techniques that use new hardware and software, however, have made detecting and locating stray current more efficient and intuitive.

Many factors have caused both the risk from and presence of stray-current corrosion to increase sharply in the past decade. These include:

- Increased use of underground construction.
- More crowded right-of-ways, with more sources for static stray current.
- More sources of dynamic stray current from mines, DC rail, and other dynamic sources.
- Increased cathodic-protection currents due to aging pipeline systems, raising the current necessary for protection.
- Increased loads of mines, DC rails, and other systems, raising the current demand from these systems and potentially increasing the potential for stray-current corrosion.

Software written to analyze stray-current mapping data easily scales the data to suit the operator, using the improved processing power and graphics ability of current personal computer technology (Fig. 1).

Background

The four main methods of detecting and measuring stray currents are:

1. *Voltage measurements and recording.* To be accurate, these measurements must be logged for intervals, ideally synchronized with other measurement stations. Time stamping the readings allows their presence to be compared to external events. This technique does not report current movement, only the related change in potentials.

2. *Current span—line drop.* Ohm's Law says the flow of a current through a resistance creates a voltage. Manufacturers' tables provide or allow calculation of the resistance per unit length of gas pipe. Measuring potential at two points allows calculation of the current. A longer run helps reduce errors.

This method can prove difficult in application for a number of reasons: Access points may be difficult to gain entry through; such points may be rare or distant; changes in pipe diameter or construction, especially if undocumented, will affect the calculation. Replacement of gas lines with plastic sections, even if tracer wires are bonded through, will have drastic changes on impedance.

3. *Current clamp-on meter.* Two varieties of this method exist; both connect a pickup coil completely around the pipe. Existing pipelines require an excavation or connection at a suitable aboveground point. Installation can also occur either at the time of construction or as part of a survey program. Permanently installed coils will use leads brought up to a sealed enclosure where temporary or permanent test equipment and loggers can be connected.

4. *Electromagnetic stray-current mapping.* This is the newest technique and provides the main focus of this article. A consortium including the Northeast Gas Association, Gas Research Institute, and a number of operators in North America and Europe developed the technique, seeking to create a tool that was easy to deploy and intuitive to use.

Since the flow of any current results in an electromagnetic field, measuring and making calculations based on the EM field surrounding a pipeline would allow all required data to be deduced. The EM inertness of most types of ground cover (dirt, sand, water, asphalt, and concrete) allows measurements to be taken above ground.

The sensors have to respond from very low frequencies (down to DC) up to several harmonics of power-line frequency. Traditional antenna coils do not respond to low frequencies very well, but modern solid-state magnetometers do.

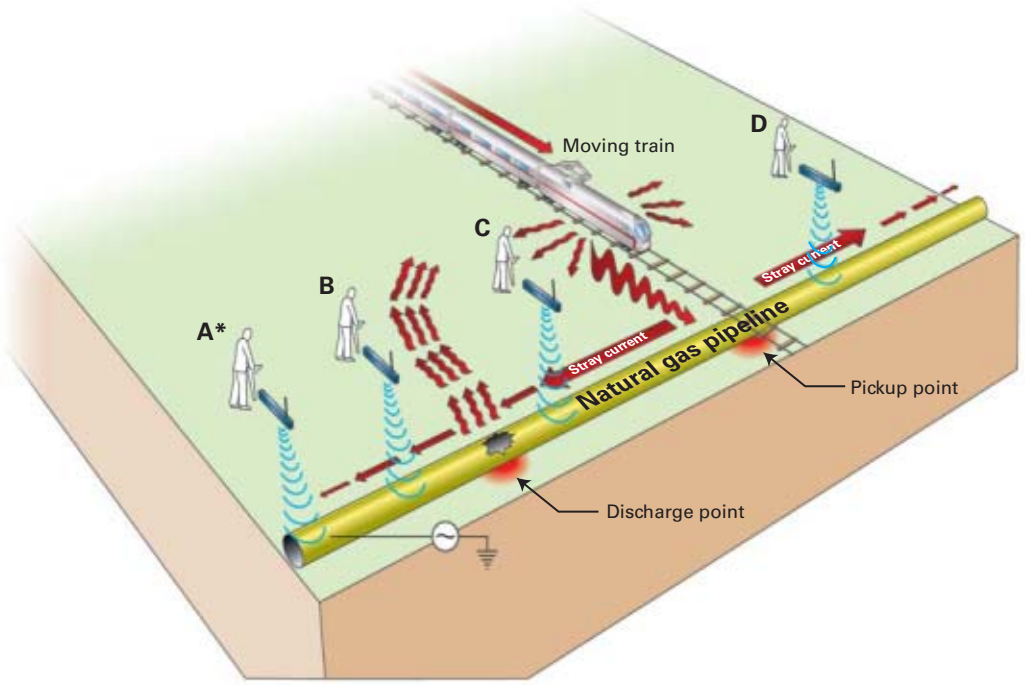
Arranging them in vector pairs or triads allows both the magnitude and direction of the EM fields to be measured. Arranging several sets of sensors along a length gives all the information needed to determine the size, shape, intensity, and depth of an EM field. These readings in turn allow easy calculation of the magnitude and direction of the current causing the EM field.

Adjacent large or moving masses of metals and EM fields on adjacent utilities alter EM fields. As EM fields increase exponentially with decreasing distance, positioning the sensors closer to the desired EM field quickly negates the effects of any distorting fields. Pushing an optional sensor developed for these applications into the ground gets the magnetometers closer to the pipe under test. A simple T-handle probe or plunger bar with sensors along its length completes this task.

The accelerated recording rate

Rail system crossing interference

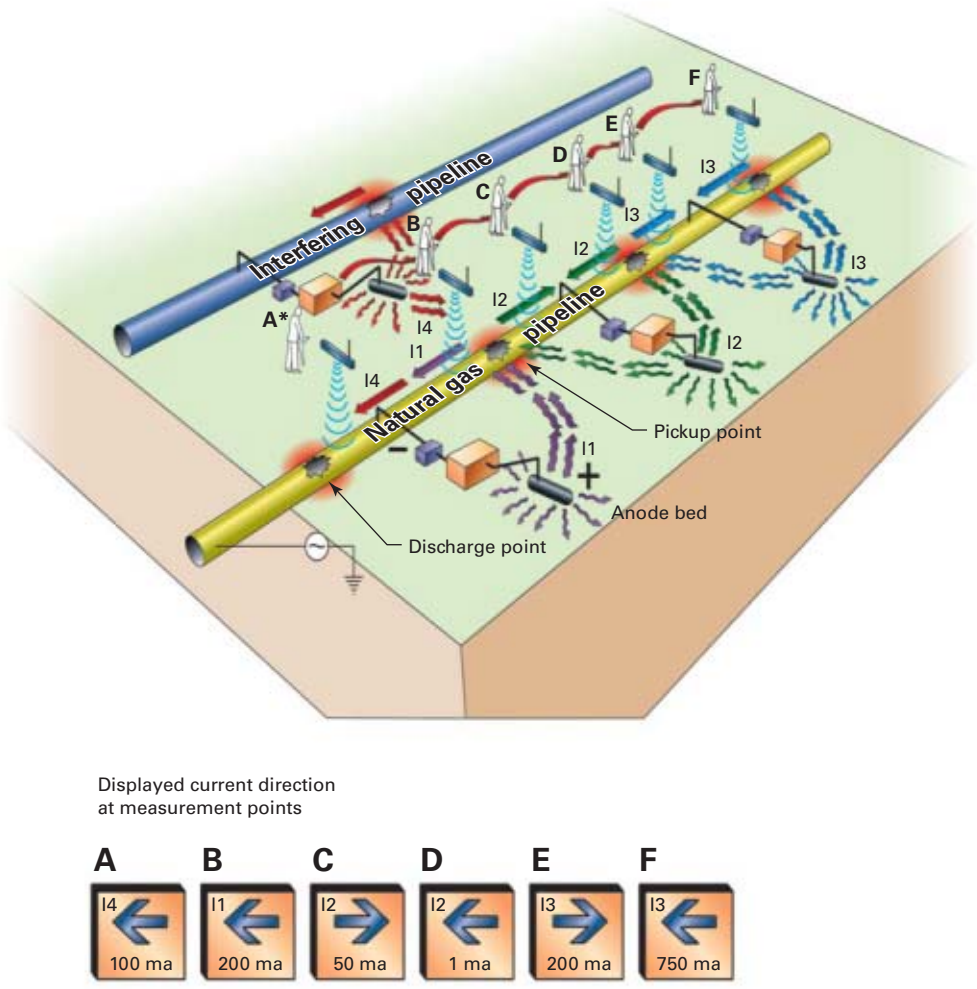
Fig. 2



*User measures current at each point, A through D, with sensor bar and receiver.

IDENTIFYING MULTIPLE RECTIFIER CURRENT CONTRIBUTIONS

Fig. 3



*User measures current at each point, A through F, with sensor bar and display laptop.

brought about by efficient large-capacity modern memory allows determination of whether a signal is periodic.

For example, a reading taken once per second would suit recording slow changes such as telluric currents but would completely miss higher frequencies (such as 60 hz), which would show up as random noise. Sampling faster than the target frequency will capture its limits. The Nyquist theorem must only be met if an exact reconstruction is required.

Software written to analyze stray-current mapping data easily scales the data to suit the operator. The Y-axis displays current and voltages, the X-axis, time (Fig. 1). Overall data trends appear easily, as do areas of interest.

Placement of two pairs of cursors causes the program to display the change in time and changes in current or voltage. The relative placement of the bar during the fieldwork stage of an SC survey shows the direction of current, requiring use of checklists and notes for each deployment point.

Theory

Interfering currents can be either dynamic (electric rail) or static (other cathodic protection systems in steady-state operation). Observing the currents flowing on the target pipeline provides one step in solving an SC problem. Confirming the SC source, however, requires slightly different approaches for each current type.

Dynamic currents fluctuate, making stray currents difficult to identify. Localized magnetic fluctuations can also create interference and must be filtered out. Measurements near electric-rail systems, to simplify the survey, must reflect normal operations. Rail system movements are unique enough, however, that the patterns of current change can both identify the system itself and allow identification (and invalidation) of unrelated magnetic fluctuations.

The technique requires two SC detection devices, one near the expected pickup point and a second roving bar that takes measurements at a succession of points along the pipeline (Fig. 2). Loading all readings into the software simultaneously makes a number of analysis tools, both manual and automatic, available.

Readings at one bar that do not appear at the other show a local magnetic anomaly, a vehicle passing by for example, and are discounted. Comparing remaining readings with similarly shaped indications shows the difference

between the calculated magnitudes of current and how much current has been gained or lost between the position of the reference bar and the position of the roving bar. Comparing these changes in current along the length of the pipeline makes areas of pickup and discharge evident.

Static currents may also exist, such as a foreign CP system suspected of adding or discharging current from the target system. Cooperation between the operators of the different systems makes these currents easier to confirm. Interrupting the currents with a unique pattern identifies each source.

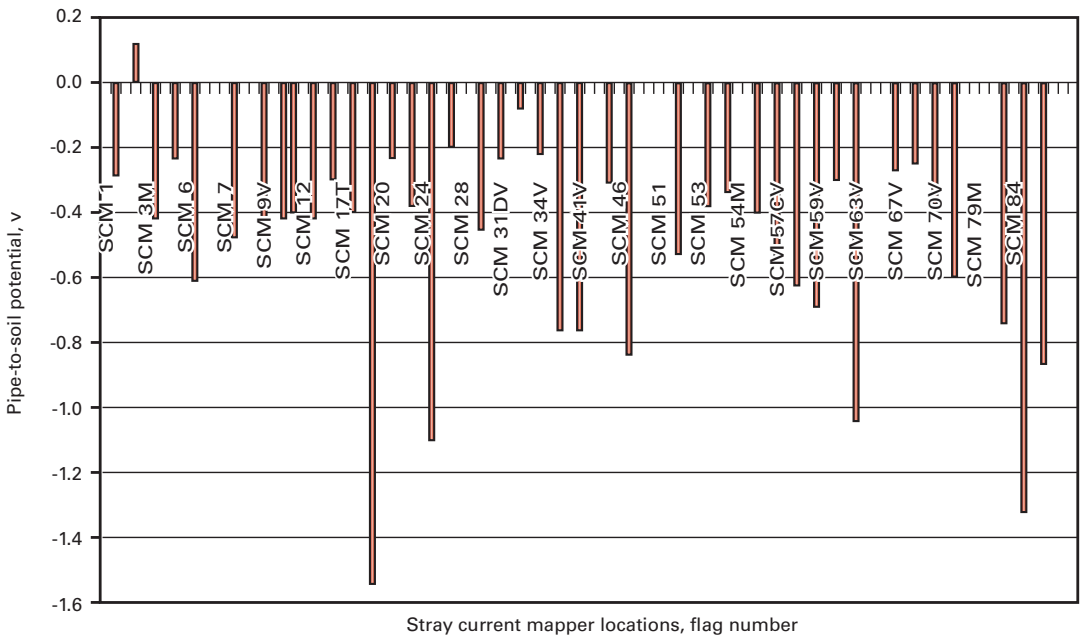
Using multiple patterns and synchronized interrupters will allow different sources to be identified; whether each individual rectifier or the entire system. Suitable software on the measurement devices or on the analysis computer will automatically calculate the magnitude and direction of any currents on the pipeline occurring at these unique patterns.

Moving the measurement bar along the target pipeline and observing the currents in the test locations will complete an SC survey. Crossing a pickup or discharge point causes an observable change in the reported current (Fig. 3).

This system can also measure AC currents, though their synchronization makes interrupting suspected sources difficult. Inductive energy is proportional to the load on the AC source and may vary with time-of-day. On a three-phase AC system, the balance between the phases also may change, creating an

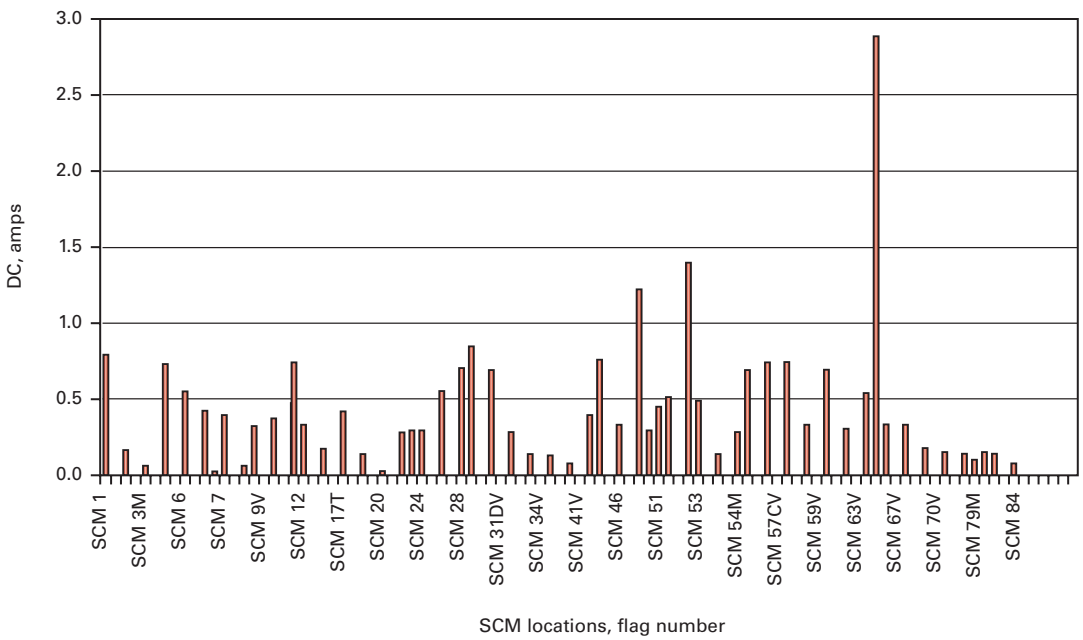
LEAST NEGATIVE POTENTIALS

Fig. 4



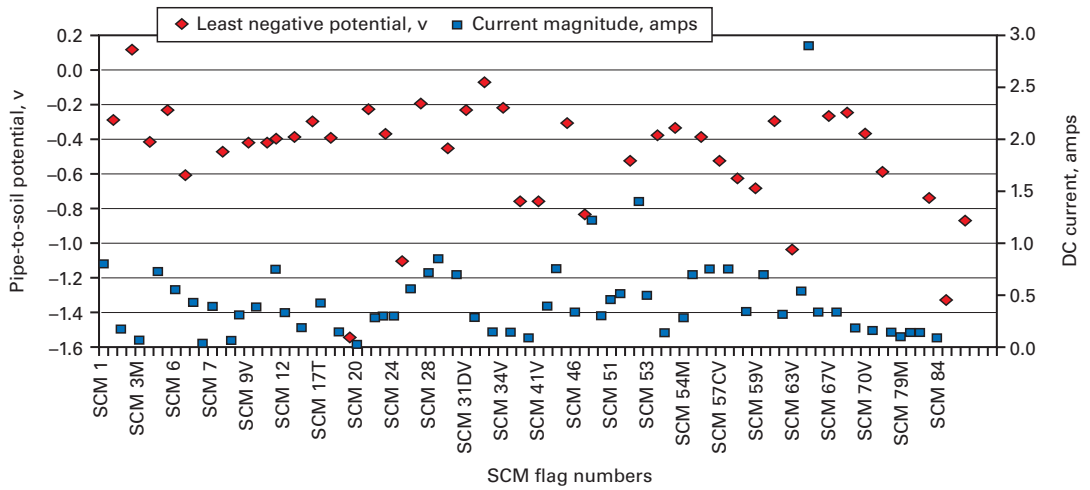
STRAY CURRENT PEAK MEASUREMENTS

Fig. 5



CURRENT VS. VOLTAGE

Fig. 6



This computer display shows logged current measurement data at flags 59-65. Patterns can occur in smaller areas and the survey may not show all the patterns occurring between locations logged (Fig. 7).

EM field where a well-balanced system had earlier negated it. A long recording ability, however, will allow observation of daylong trends.

Stray-current mapping gathers and quantifies the data in each instance. Analysis of these results by a qualified person allows proper understanding of what the information is saying and how to use it to mitigate problems.

The strength of this method is the ease of gathering the data. Placing the sensor bar on the ground above the target pipeline and setting up a communications link to a properly programmed computer will suffice in most cases.

Case studies

A dynamic stray-current survey on an NGL pipeline is the first case study.

The survey employed a number of testing techniques at various locations but not on the entire pipeline, including:

- Pipe locating (for location and depth).
- Stray-current mapping.
- Pipe-to-soil potential measurements.
- Global-positioning-system survey, accurate within 1 m.

Testing concentrated on the best techniques for each location, including stray-current measurement readings, with all techniques not employed at all locations. The survey attempted to take measurements roughly every 1 mile of the pipeline's 60-mile length.

- Individual recording logs at these various locations recorded 24 hr worth of information, with a total of 96 different logged recordings amounting to about 2,300 hr of logged events. The survey concentrated on accessible areas and areas of known or identified stray-current influence and used the following tools:
- Four stray-current mappers, used to log both current and pipe-to-soil potentials.
- Pipe and cable locator, used for location and depth of cover.
- 4 copper or copper-sulfate reference half cells, for measuring pipe-to-

soil potentials.

- Digital multi meter, to check test leads and other areas where the reference cells were attached during the logs.
- Stray-current mapper viewer software used in the analysis of the stray current and pipe-to-soil voltage logs.
- Spreadsheets for the compilation of the data.
- Handheld GPS for recording positions of the flags at the logged locations, accurate within 1 m.

The line surveyed with the stray-current mapper lay in areas with obtainable access to the NGL pipeline and normally in areas with nearby access to a pipeline test station. Placing the SCM across the NGL pipeline occurred in such a way that any forward measurements of the current direction would indicate that the current was flowing downstream (with the normal pipeline product flow) and any backward measurements of the current direction would indicate that the current was flowing upstream.

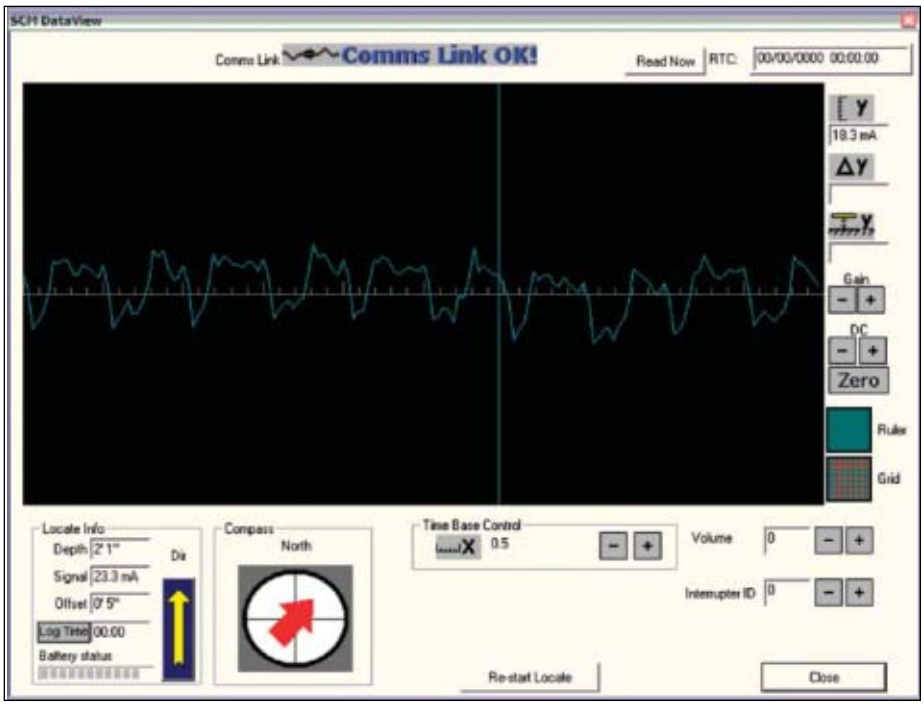
The survey focused on areas of least negative pipe-to-soil potentials and areas with the most current flow at the logged locations.

Fig. 4 shows the least negative potentials at the logged locations. The least negative, and in fact positive, potential lies at SCM flag 3J; a +0.123-v positive value which may be caused by a nearby bare 20-in. line.

The static stray-current survey also identified this area. The next least negative area lay at SCM flag 32, where a -0.075 voltage was logged. Many other events measured less than –0.300 v.

Fig. 5 shows the peak current measurements at the logged locations. The most current measured at any location lay at flag 65 at 2.887 amp. This event did not correspond with events logged at the same time at other locations and may have been localized. A commercial saw mill stood about 0.5 miles from the location.

The two other most significant current flow areas lay at SCM flag 52, with a measured amperage of 1.397 and



The 23.3-ma reading shown in the lower left of this screen represents the most current measured at any location on Operator 1's rectifiers (Fig. 8).

at SCM flag 47, 1.210 amp; both near a coal mining operation. Other areas along the pipeline have current flows above 0.5 amp, including SCM flags 4 and 6, SCM flags 26D-31D, SCM flags 55-58 and SCM flags 60 and 65.

Fig. 6 shows the peak current with the least negative potentials at the logged locations. The least negative potentials are not always associated with the most current flow. Not being at the actual pipeline position where the discharge is occurring likely causes this.

Being very near or on top of the current's discharge position would likely lead to the least negative pipeline potentials being measured at these locations, provided there was no error in the measurements due to other nearby interfering sources.

SCM flag 30 showed a –0.456 voltage potential and 0.848 amp of current. SCM flag 31D has a 0.232 voltage potential and 0.635 amp of current, and a –0.075 voltage potential and 0.274 amp of current exist at SCM flag 32. These measurements indicate discharge points between flags 30 and 32, with the most significant discharge occurring between 31D and 32.

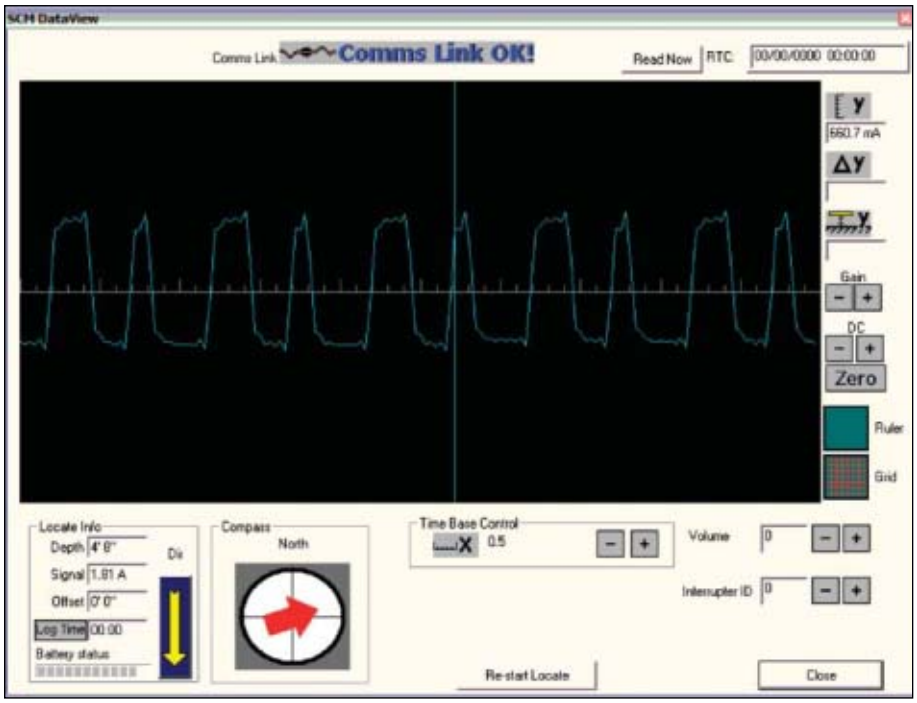
Other areas with the same types of patterns include but are not limited to SCM flags 46-53, and SCM flags 59-69. These types of patterns can occur in smaller areas and the survey to date may not show all of the patterns occurring between the locations logged. Fig. 7 shows an example of logged current-measurement data at flags 59-65.

Static example

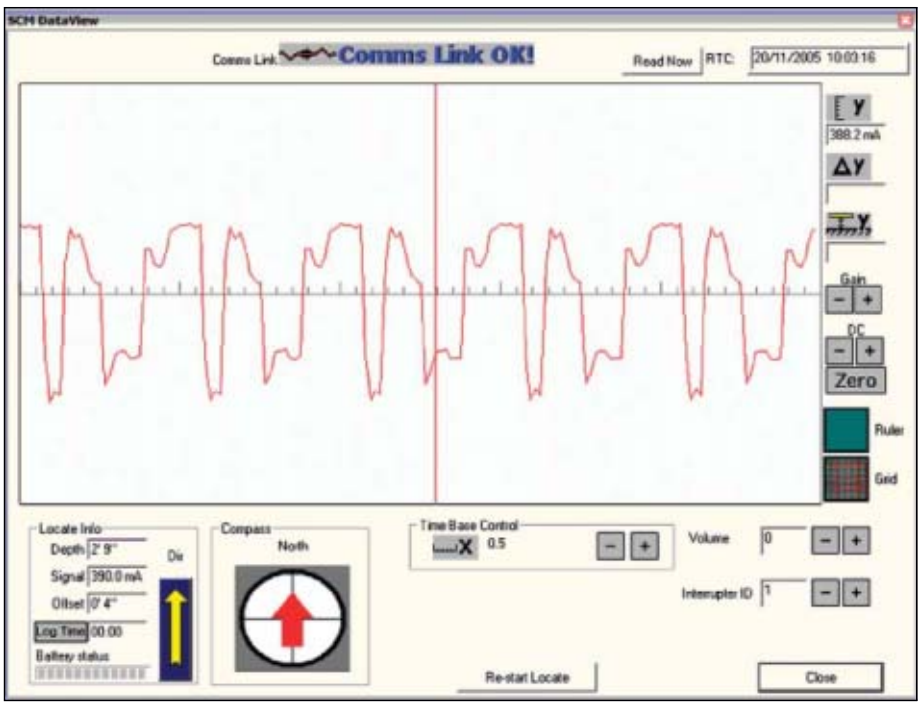
A static stray-current survey conducted with the stray current on an NGL pipeline used the following techniques at various locations but not on the entire pipeline:

- Pipe locating (for location and depth).
- Interrupting current from foreign sources.
- Stray-current mapping.
- Pipe-to-soil potential measurements (in limited amounts).
- 1-m accurate GPS.

The survey concentrated on the best techniques, including stray-current measurement readings from the foreign interrupted current sources. Survey-



A 1-2 amp discharge from the NGL pipeline to a nearby 20-in. pipeline occurs once the two lines are sufficiently close (Fig. 9).



This computer display shows a maximum current measurement reading of 390 ma for Operator 3, Rectifier 1 (Fig. 10).

ing the 60-mile pipeline took place as needed at various intervals, with a total of 10 different foreign sources of rectified current interrupted.

These interrupted sources of current provided the basis of the survey; unidentified or unknown sources of current that were not interrupted were not measured. Measurements occurred at locations every 0.5-1 mile along the pipeline and before and after every known foreign pipeline crossing using the following techniques:

- GPS current interruption of four foreign transmission pipeline rectifiers from one operator, GPS current interruption of three foreign rectifiers from a second operator, and GPS current interruption of three foreign rectifiers from a third.
- Stray-current mapping to map the distribution of interrupted currents at various locations on the NGL pipeline.
- On and off pipe-to-soil potentials (not logged) at selected test stations.

Much of the line surveyed with the stray-current mapper lay in older areas of the NGL pipeline that had no coating where the pipe-to-soil measurements are low. Placement of the SCM across the NGL pipeline took place such that any forward measurements of the current direction would indicate that the current was flowing downstream and any backward measurements of the current direction would indicate that the current was flowing upstream.

Reviewing SCM measurements on foreign pipelines should take place according to how the bar was set up in relation to the north-south orientation of the pipeline direction indicated on the SCM log screen.

Operator 1 rectifiers. Interference current measurements on the NGL pipeline from these rectifiers do not indicate any substantial amount of stray-current influence. The most current at any one location measured 23 ma at flag 7, upstream from a pipeline crossing (Fig. 9). The limited current measured after the crossing suggests that a discharge of 10-20 ma may be occurring in this area. An anode on the NGL pipeline near this location could be discharging this current. No known bonds exist between Operator 1 and the NGL pipeline.

Operator 2 rectifiers. These interfering sources of current have a more significant effect on the integrity of the NGL pipeline, with the largest source of

interfering current coming from one of the rectifiers.

Rectifier 2 affects the NGL pipeline positively until the nearby 20-in. OD pipeline draws close and runs parallel between Flags 3J and 3L, at which point a 1-2 amp charge moves from the NGL pipeline to the 20-in. pipeline (Fig. 10). Both pipelines are uncoated in this area, providing a potential path for current discharge. Pipe-to-soil measurements also show possible current discharge at this location.

A bond wire connects the NGL pipeline and the 20-in. pipeline 1,000 ft south of this location where the pipes enter the ground.

Operator 3 rectifiers. Rectifier 1's current gradually increases and is beneficial until being mitigated through a direct bond with Operator 3; a maximum current measurement of 390 ma at flag 83S (Fig. 11). The close proximity of an Operator 3 pipeline prevented current measurements north of this area.

An SCM smart probe could ensure all current was mitigated correctly. There is enough net current pick up from Operator 3's rectifier, however, to protect the pipeline in this area.

Rectifier 2's current gradually increases and is beneficial until mitigated by a direct bond with Operator 3; a maximum current measurement of 78 ma at flag 83S. The close proximity of an Operator 3 pipeline prevented current measurements north of this area.

An SCM smart probe could ensure all current was mitigated correctly. There is enough net current pickup from the rectifier, however, to protect the pipeline in this area. ✦

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National Oilwell Varco (NOV)

Houston, has announced the following new appointments. Mark Reese has been named as president of NOV's Rig Solutions group, Jeremy Thigpen as president of Downhole and Pumping Solutions, Robert Workman as president of Distribution Services group, and Kirk Shelton as president of Mission/Mono Products.


Reese


Thigpen

Reese joined National Supply Co. in 1981, and has held a variety of management positions with National Oilwell Varco since then. Thigpen joined National Oilwell in 1997 as a financial analyst. Both Reese and Thigpen completed graduate work at the Harvard Business School. Workman, who holds an MBA from Rice University, has served in leadership positions since joining National Oilwell in 1991. Shelton, a graduate of East Central University, started work in 1980 for TRW-Mission, which was the first acquisition of National Oilwell.


Shelton


Workman

National Oilwell Varco is a worldwide leader in the design, manufacture, and sale of comprehensive systems and components used in oil and gas drilling and production, tubular inspection, internal tubular coatings, integrated systems, downhole tools, lifting and handling equipment, as well as in providing supply chain integration services to the upstream oil and gas industry.

Amec plc

Houston, has announced that Susan Waller has joined the firm as vice-president.

Waller will hold senior oil and gas business development responsibilities with Amec's earth & environmental business. Her 30 years of energy industry experience includes positions with Shaw Environmental & Infrastructure, RCP Inc., and El Paso Energy.

Amec plc provides a full range of environmental and geotechnical engineering services to the North American and international oil and gas industry, supporting upstream and downstream activities.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	9-7 2007	8-31 2007	9-7 2007	8-31 2007	9-7 2007	8-31 2007	*9-8 2006
	1,000 b/d						
Total motor gasoline	1,004	1,312	12	2	1,016	1,314	1,084
Mo. gas. blending comp.	563	879	12	—	575	879	799
Distillate	302	370	50	19	352	389	384
Residual	267	162	114	—	381	162	328
Jet fuel-kerosine	112	102	82	122	194	224	124
Propane-propylene	239	122	1	2	240	124	216
Other	444	(127)	(11)	102	433	(25)	554
Total products	**2,931**	**2,820**	**260**	**247**	**3,191**	**3,067**	**3,489**
Total crude	**8,521**	**9,199**	**1,042**	**1,038**	**9,563**	**10,237**	**10,597**
Total imports	**11,452**	**12,019**	**1,302**	**1,285**	**12,754**	**13,304**	**14,086**

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

Purvin & Gertz LNG netbacks—Sept. 14, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.63	4.59	5.82	4.49	5.18	5.80
Everett	4.62	2.58	4.25	2.68	3.14	4.91
Isle of Grain	5.17	3.10	4.41	3.05	3.67	4.62
Lake Charles	3.43	2.30	3.18	2.34	2.30	4.03
Sodegaura	5.19	7.33	5.39	7.03	6.36	4.65
Zeebrugge	6.42	4.32	5.79	4.22	4.89	5.82

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	15,576	49,175	23,082	10,743	55,641	13,868	4,882
PADD 2	65,980	47,718	15,643	7,037	28,901	1,350	23,148
PADD 3	175,613	58,188	24,446	12,929	33,759	15,828	26,982
PADD 4	13,707	5,933	1,810	600	2,721	311	[1]2,611
PADD 5	51,773	29,403	20,695	10,224	12,941	5,436	—
Sept. 7, 2007	**322,649**	**190,417**	**85,676**	**41,533**	**133,963**	**36,793**	**57,623**
Aug. 31, 2007	**329,660**	**191,083**	**85,143**	**41,186**	**132,170**	**36,375**	**55,162**
Sept. 8, 2006[2]	**327,724**	**206,994**	**93,491**	**40,931**	**144,588**	**42,766**	**65,684**

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

Refinery report—Sept. 7, 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	1,613	1,619	1,845	82	473	132	69
PADD 2	3,413	3,397	2,090	237	960	53	184
PADD 3	7,449	7,321	3,158	646	1,911	354	692
PADD 4	536	531	276	22	156	13	[1]145
PADD 5	2,784	2,696	1,542	409	630	162	—
Sept. 7, 2007	**15,795**	**15,564**	**8,911**	**1,396**	**4,130**	**714**	**1,090**
Aug. 31, 2007	**16,067**	**15,901**	**9,157**	**1,473**	**4,317**	**658**	**1,017**
Sept. 8, 2006[2]	**16,184**	**16,018**	**9,073**	**1,493**	**4,466**	**635**	**1,045**
	17,448 operable capacity		**90.5% utilization rate**				

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

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

OGJ crack spread

	*9-14-07	*9-15-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	88.78	68.29	20.49	30.0
Brent crude	76.56	61.83	14.73	23.8
Crack spread	12.21	6.46	5.76	89.2
FUTURES MARKET PRICES				
One month				
Product value	87.66	69.97	17.68	25.3
Light sweet crude	78.96	63.98	14.98	23.4
Crack spread	8.69	5.99	2.70	45.0
Six month				
Product value	87.55	76.96	10.59	13.8
Light sweet crude	74.63	68.08	6.55	9.6
Crack spread	12.92	8.88	4.04	45.4

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

OGJ GASOLINE PRICES

	Price ex tax 9-12-07	Pump price* 9-12-07	Pump price 9-13-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	238.4	278.1	258.1
Baltimore	226.7	268.6	266.8
Boston	223.7	265.6	267.8
Buffalo	221.5	281.6	280.8
Miami	243.0	293.3	278.5
Newark	230.9	263.8	268.3
New York	221.1	281.2	285.5
Norfolk	225.1	262.7	245.8
Philadelphia	228.6	279.3	277.5
Pittsburgh	226.9	277.6	268.3
Wash., DC	242.2	280.6	281.6
PAD I avg.	229.8	275.7	270.8
Chicago	271.2	322.1	300.7
Cleveland	239.6	286.0	236.6
Des Moines	236.1	276.5	226.5
Detroit	258.5	307.7	247.8
Indianapolis	250.3	295.3	237.7
Kansas City	248.5	284.5	234.7
Louisville	261.0	297.9	231.4
Memphis	226.6	266.4	248.9
Milwaukee	251.3	302.6	267.7
Minn.-St. Paul	253.2	293.6	244.7
Oklahoma City	250.3	285.7	232.2
Omaha	239.1	285.5	233.3
St. Louis	232.3	268.3	239.3
Tulsa	249.2	284.6	238.6
Wichita	236.5	279.9	237.0
PAD II avg.	246.9	289.1	243.8
Albuquerque	241.0	277.4	261.1
Birmingham	229.7	268.4	240.1
Dallas-Fort Worth	228.9	267.3	236.9
Houston	235.8	274.2	239.6
Little Rock	230.0	270.2	242.7
New Orleans	235.7	274.1	264.7
San Antonio	228.9	267.3	252.5
PAD III avg.	232.9	271.3	248.2
Cheyenne	247.8	280.2	278.9
Denver	248.9	289.3	286.0
Salt Lake City	248.4	291.3	290.4
PAD IV avg.	248.4	286.9	285.1
Los Angeles	219.4	277.9	288.7
Phoenix	247.9	285.3	256.2
Portland	240.8	284.1	286.0
San Diego	229.7	288.2	292.1
San Francisco	226.0	284.5	305.5
Seattle	227.8	280.2	294.3
PAD V avg.	231.9	283.4	287.1
Week's avg.	**238.1**	**281.6**	**260.8**
Aug. avg.	**237.2**	**280.8**	**296.7**
July avg.	**251.6**	**295.2**	**295.2**
2007 to date	**229.1**	**272.7**	—
2006 to date	**223.5**	**267.0**	—

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

REFINED PRODUCT PRICES

	9-7-07 ¢/gal		9-7-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	205.20	New York Harbor	212.73
Gulf Coast	207.70	Gulf Coast	209.48
Los Angeles	212.70	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	193.20	ARA	213.77
Singapore	190.19	Singapore	212.38
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	208.70	New York Harbor	133.86
Gulf Coast	212.20	Gulf Coast	141.07
Los Angeles	213.70	Los Angeles	148.88
		ARA	129.09
		Singapore	141.21

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

BAKER HUGHES RIG COUNT

	9-14-07	9-15-06
Alabama	5	4
Alaska	5	5
Arkansas	48	28
California	37	29
Land	35	25
Offshore	2	4
Colorado	120	94
Florida	1	0
Illinois	1	0
Indiana	1	0
Kansas	13	10
Kentucky	11	9
Louisiana	178	202
N. Land	60	57
S. Inland waters	28	19
S. Land	25	45
Offshore	65	81
Maryland	1	0
Michigan	1	2
Mississippi	12	14
Montana	13	17
Nebraska	0	0
New Mexico	75	96
New York	6	7
North Dakota	40	38
Ohio	15	9
Oklahoma	197	193
Pennsylvania	16	14
South Dakota	2	3
Texas	829	780
Offshore	6	9
Inland waters	1	2
Dist. 1	25	23
Dist. 2	34	26
Dist. 3	55	58
Dist. 4	84	94
Dist. 5	187	141
Dist. 6	125	111
Dist. 7B	35	44
Dist. 7C	60	37
Dist. 8	105	94
Dist. 8A	18	26
Dist. 9	36	37
Dist. 10	58	78
Utah	40	44
West Virginia	33	24
Wyoming	75	109
Others—NV-3; TN-5; VA-3; WA-1	12	6
Total US	**1,787**	**1,737**
Total Canada	**364**	**502**
Grand total	**2,151**	**2,239**
Oil rigs	298	310
Gas rigs	1,483	1,422
Total offshore	75	95
Total cum. avg. YTD	**1,760**	**1,619**

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	9-14-07 Rig count	9-14-07 Percent footage*	9-15-06 Rig count	9-15-06 Percent footage*
0-2,500	65	7.6	44	—
2,501-5,000	112	58.0	77	37.6
5,001-7,500	223	21.9	234	23.5
7,501-10,000	430	3.4	395	5.8
10,001-12,500	437	1.8	399	2.2
12,501-15,000	275	0.7	290	0.3
15,001-17,500	116	—	110	—
17,501-20,000	67	—	73	—
20,001-over	33	—	32	—
Total	**1,758**	**8.1**	**1,654**	**7.0**
INLAND	39		41	
LAND	1,659		1,548	
OFFSHORE	60		65	

*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]9-14-07	[2]9-15-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	17	20
Alaska	753	641
California	660	678
Colorado	50	60
Florida	6	7
Illinois	30	27
Kansas	95	98
Louisiana	1,340	1,402
Michigan	13	14
Mississippi	49	48
Montana	93	100
New Mexico	165	163
North Dakota	105	112
Oklahoma	164	173
Texas	1,344	1,348
Utah	44	49
Wyoming	141	143
All others	60	72
Total	**5,129**	**5,155**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	9-14-07
Alaska-North Slope 27°	69.08
South Louisiana Sweet	80.00
California-Kern River 13°	68.15
Lost Hills 30°	76.30
Southwest Wyoming Sweet	72.10
East Texas Sweet	75.25
West Texas Sour 34°	69.75
West Texas Intermediate	75.75
Oklahoma Sweet	75.75
Texas Upper Gulf Coast	72.25
Michigan Sour	68.75
Kansas Common	74.75
North Dakota Sweet	66.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	8-31-07
United Kingdom-Brent 38°	70.22
Russia-Urals 32°	68.04
Saudi Light 34°	67.69
Dubai Fateh 32°	67.23
Algeria Saharan 44°	72.06
Nigeria-Bonny Light 37°	73.62
Indonesia-Minas 34°	72.84
Venezuela-Tia Juana Light 31°	66.44
Mexico-Isthmus 33°	66.33
OPEC basket	69.46
Total OPEC[2]	68.83
Total non-OPEC[2]	68.02
Total world[2]	68.46
US imports[3]	66.47

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume. NOTE: No new data at presstime.

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

US NATURAL GAS STORAGE[1]

	9-7-07	8-31-07	Change
	bcf		
Producing region	915	903	12
Consuming region east	1,746	1,696	50
Consuming region west	408	406	2
Total US	**3,069**	**3,005**	**64**
	June 07	**June 06**	**Change, %**
Total US[2]	**2,580**	**2,617**	**–1.4**

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

Statistics

World oil balance

	-2007- 1st qtr.	2006 4th qtr.	3rd qtr.	2nd qtr.	1st qtr.	-2005- 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.07	21.01	21.14	20.87	20.75	21.14
Canada	2.35	2.26	2.26	2.14	2.24	2.33
Mexico	2.05	2.00	1.96	1.98	2.05	2.10
Japan	5.39	5.29	4.75	4.72	5.89	5.46
South Korea	2.35	2.32	2.04	2.04	2.29	2.23
France	1.97	1.95	1.93	1.87	2.09	1.96
Italy	1.69	1.71	1.68	1.65	1.89	1.78
United Kingdom	1.80	1.81	1.78	1.82	1.91	1.84
Germany	2.42	2.71	2.75	2.59	2.60	2.63
Other OECD Europe	7.30	7.46	7.43	7.21	7.40	7.49
Australia & New Zealand	1.09	1.10	1.07	1.05	1.06	1.10
Total OECD	**49.48**	**49.62**	**48.79**	**47.95**	**50.17**	**50.06**
NON-OECD						
China	7.53	7.53	7.24	7.30	7.02	7.07
FSU	4.43	4.38	4.18	4.20	4.35	4.66
Non-OECD Europe	0.75	0.71	0.66	0.71	0.75	0.69
Other Asia	8.60	8.70	8.12	8.59	8.60	8.89
Other non-OECD	14.62	14.51	14.74	14.47	14.27	15.02
Total non-OECD	**35.93**	**35.83**	**35.24**	**35.27**	**34.89**	**36.83**
TOTAL DEMAND	**85.41**	**85.45**	**84.03**	**83.22**	**85.06**	**86.39**
SUPPLY						
OECD						
US	8.43	8.46	8.48	8.35	8.18	7.74
Canada	3.43	3.40	3.32	3.16	3.29	3.28
Mexico	3.59	3.52	3.71	3.79	3.80	3.75
North Sea	4.80	4.76	4.51	4.71	5.11	5.05
Other OECD	1.47	1.52	1.52	1.41	1.41	1.51
Total OECD	**21.72**	**21.66**	**21.54**	**21.42**	**21.798**	**21.33**
NON-OECD						
FSU	12.58	12.45	12.23	12.03	11.78	11.97
China	3.84	3.83	3.83	3.85	3.83	3.75
Other non-OECD	11.43	11.67	11.87	11.67	11.49	11.75
Total non-OECD, non-OPEC	**27.85**	**27.95**	**27.93**	**27.55**	**27.10**	**27.47**
OPEC*	**34.52**	**35.94**	**36.62**	**36.16**	**36.33**	**36.70**
TOTAL SUPPLY	**84.09**	**85.55**	**96.09**	**85.13**	**85.22**	**85.50**
Stock change	**–1.42**	**0.12**	**1.95**	**1.81**	**0.18**	**–0.89**

*Includes Angola. **NOTE: No new data at presstime.**
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD total net oil imports

	May 2007	Apr. 2007	Mar. 2007	May 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,198	–1,279	–1,247	–1,233	35	–2.8
US	12,784	12,583	12,634	12,862	–78	–0.6
Mexico	–1,560	–1,497	–1,667	–1,874	314	–16.8
France	1,657	2,284	1,311	1,670	–13	–0.8
Germany	1,998	2,026	2,132	2,328	–330	–14.2
Italy	1,468	1,635	1,650	1,369	99	7.2
Netherlands	1,157	992	838	869	288	33.1
Spain	1,566	1,662	1,488	1,465	101	6.9
Other importers	3,981	3,579	3,614	4,017	–36	–0.9
Norway	–2,440	–2,275	–2,476	–2,251	–189	8.4
United Kingdom	155	–206	13	440	–285	–64.8
Total OECD Europe	**9,542**	**9,697**	**8,570**	**9,907**	**–365**	**–3.7**
Japan	4,331	4,802	5,013	4,965	–634	–12.8
South Korea	2,444	1,875	2,615	2,354	90	3.8
Other OECD	998	742	1,027	1,181	–183	–15.5
Total OECD	**27,341**	**26,923**	**26,945**	**28,162**	**–821**	**–2.9**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	May 2007	Apr. 2007	Mar. 2007	May 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	432	436	380	238	194	81.5
US	6,187	5,977	6,296	6,173	14	0.2
Mexico	20	21	28	10	10	100.0
France	779	821	534	810	–31	–3.8
Germany	396	465	330	494	–98	–19.8
Italy	1,114	1,187	1,230	989	125	12.6
Netherlands	513	679	521	517	–4	–0.8
Spain	721	637	627	674	47	7.0
Other importers	1,223	1,275	972	1,301	–78	–6.0
United Kingdom	221	264	248	271	–50	–18.5
Total OECD Europe	**4,967**	**5,328**	**4,462**	**5,056**	**–89**	**–1.8**
Japan	3,774	4,024	4,788	4,341	–567	–13.1
South Korea	2,441	2,136	2,485	2,469	–28	–1.1
Other OECD	670	741	706	767	–97	–12.6
Total OECD	**18,491**	**18,663**	**19,145**	**19,054**	**–563**	**–3.0**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	May 2007	Apr. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	744	798	723	552	171	31.0
Angola	692	526	596	448	148	33.0
Kuwait	168	135	190	160	30	18.8
Nigeria	964	948	1,100	1,207	–107	–8.9
Saudi Arabia	1,614	1,488	1,427	1,453	–26	–1.8
Venezuela	1,520	1,412	1,354	1,482	–128	–8.6
Other OPEC	485	670	601	172	429	249.4
Total OPEC	**6,187**	**5,977**	**5,991**	**5,474**	**517**	**9.4**
Canada	2,462	2,479	2,432	2,276	156	6.9
Mexico	1,617	1,572	1,604	1,785	–181	–10.1
Norway	234	198	167	204	–37	–18.1
United Kingdom	390	386	306	272	34	12.5
Virgin Islands	287	322	340	301	39	13.0
Other non-OPEC	2,987	2,962	2,734	3,165	–431	–13.6
Total non-OPEC	**7,977**	**7,919**	**7,583**	**8,003**	**–420**	**–5.2**
TOTAL IMPORTS	**14,164**	**13,896**	**13,574**	**13,477**	**97**	**0.7**

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

Oil stocks in OECD countries*

	May 2007	Apr. 2007	Mar. 2007	May 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	189	190	177	194	–5	–2.6
Germany	288	291	291	280	8	2.9
Italy	132	135	134	130	2	1.5
United Kingdom	104	105	106	105	–1	–1.0
Other OECD Europe	670	664	660	659	11	1.7
Total OECD Europe	**1,383**	**1,385**	**1,368**	**1,368**	**15**	**1.1**
Canada	181	181	186	169	12	7.1
US	1,719	1,688	1,677	1,724	–5	–0.3
Japan	611	615	615	634	–23	–3.6
South Korea	159	149	156	152	7	4.6
Other OECD	109	107	101	106	3	2.8
Total OECD	**4,162**	**4,125**	**4,103**	**4,153**	**9**	**0.2**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

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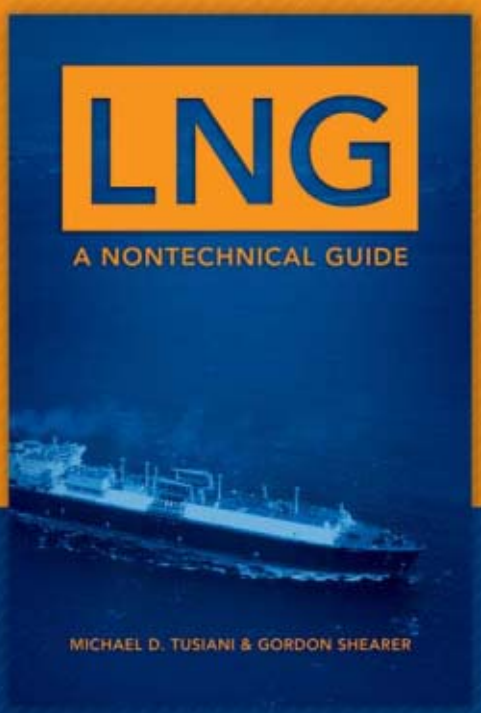

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US chases energy fantasies while EU seeks supply

Europe and the US share concern about security of energy supply. The similarity mostly ends there.

Europe has been rattled by Russia's willingness to curb deliveries of natural gas in apparent attempts to advance its political goals.

It matters little to Europe that Russia's direct targets so far have been adjacent, non-European neighbors that—depending on who's interpreting events—Moscow was trying to bring to heel or simply dunning for overdue accounts. None of that should matter to Europe. Gas not delivered on schedule during winter is gas not delivered, whatever the reason.

The Editor's Perspective

by Bob Tippee, Editor

In plenty of other ways lately, Russia has been behaving like the bully it used to be. Europe has reason to worry.

So the European Union is looking elsewhere for energy supply.

Through its European Neighborhood Policy (ENP), for example, the EU is trying to strengthen ties with bordering countries to the east and along the non-European Mediterranean coast. That energy cooperation is central to the effort is no secret.

The logic is straightforward. Europe needs more energy than its constituent countries can produce. So it goes looking for new supply.

The US needs more energy than it can produce, too. But instead of looking for more supply it cuddles itself into fantasies about conservation and alternative energy.

Unlike Europe, the US could produce more energy than it does inside its borders—off the East and West Coasts, in the eastern Gulf of Mexico, in Alaska. It just won't.

In energy-fretful Europe, this must look foolish. It is.

Europe kisses the alternative-energy ring, too, of course. EU communications about the ENP coo about neighboring countries' commitment to solar, wind, and biofuels.

Yet energy from all those sources combined in the target neighbors wouldn't displace meaningful amounts of the gas Europe imports from Russia.

The neighborhood in question includes Azerbaijan, Syria, Egypt, Libya, and Algeria—none of which, at last report, was a major exporter of wind or solar-driven electrical power or of biofuels. The EU needs and wants oil and gas, and its political varnish about alternatives fools no one.

Except, maybe, wishful thinkers in the US.

(Online Sept. 14, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Paula Dittrick, Senior Staff Writer
Sam Fletcher, Senior Writer

Crude tops record $80/bbl

The front-month crude contract closed above $80/bbl for the first time in the history of the New York Mercantile Exchange Sept. 13 upon news that Hurricane Humberto had disrupted power to three refineries in Port Arthur, Tex.

In its third consecutive record settlement that week, the October contract for benchmark US light, sweet crudes increased 18¢ to $80.09 on the New York Mercantile Exchange. That contract hit an all-time high of $80.36/bbl in intraday trading Sept. 14 before profit-taking dropped the closing price to $79.10/bbl on NYMEX.

The record high closing came 3 days after ministers of the Organization of Petroleum Exporting Countries voted in Vienna to increase production by 500,000 b/d, effective Nov. 1. The agreement excludes production by Angola and Iraq and affects only the other 10 members. Saudi Arabia's crude production is still 400,000 b/d below the October 2006 level, but that is offset by Angola's production increases. Saudi Arabia, the UAE, and Kuwait supported the production increase while Venezuela, Algeria, and Libya resisted it.

Analysts in the Houston office of Raymond James & Associates Inc. called the boost "largely symbolic, aimed to calm a skittish market that is still assessing the full extent and fallout from the US credit-market meltdown." The 10 members subject to quotas are estimated to have produced 1 million b/d above the current ceiling during August. Barclays Capital Inc. analyst Paul Horsnell in London said OPEC "probably should have increased by a tad more if there was a desire to keep the incursion above the $80/bbl reasonably limited." OPEC production already was expected to fall during November because of heavy field maintenance in the UAE. Maintenance slated for the giant Lower Zakum and Upper Zakum oil fields off Abu Dhabi could reduce output by 600,000 b/d for 2-3 weeks, Horsnell said. Additional reductions from Umm Shaif field off Abu Dhabi are likely to bring the peak reduction total up to 800,000 b/d.

"In all, an increase in output of 500,000 b/d from the rest of the OPEC 10 would do little more than cancel out the reduction in the UAE across November as a whole and leave output fairly stable," Horsnell said. "It would then be December before the increase became significant and January before that oil turned up in the market."

Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, said Sept. 17, "The OPEC decision to increase output by 500,000 b/d has been so far discounted by the market, but we think that it deserves closer attention when increases from Angola and Iraq are taken into account." Jakob said, "The overall OPEC production number for November is still difficult to assess due to maintenance in the UAE, but even with a very conservative outlook on Iraqi supplies, we should have OPEC in December producing 700,000 b/d over December 2006 and in the first quarter of 2008, [an increase of] 850,000 b/d vs. the first quarter of 2007, and this before any increases from Nigeria."

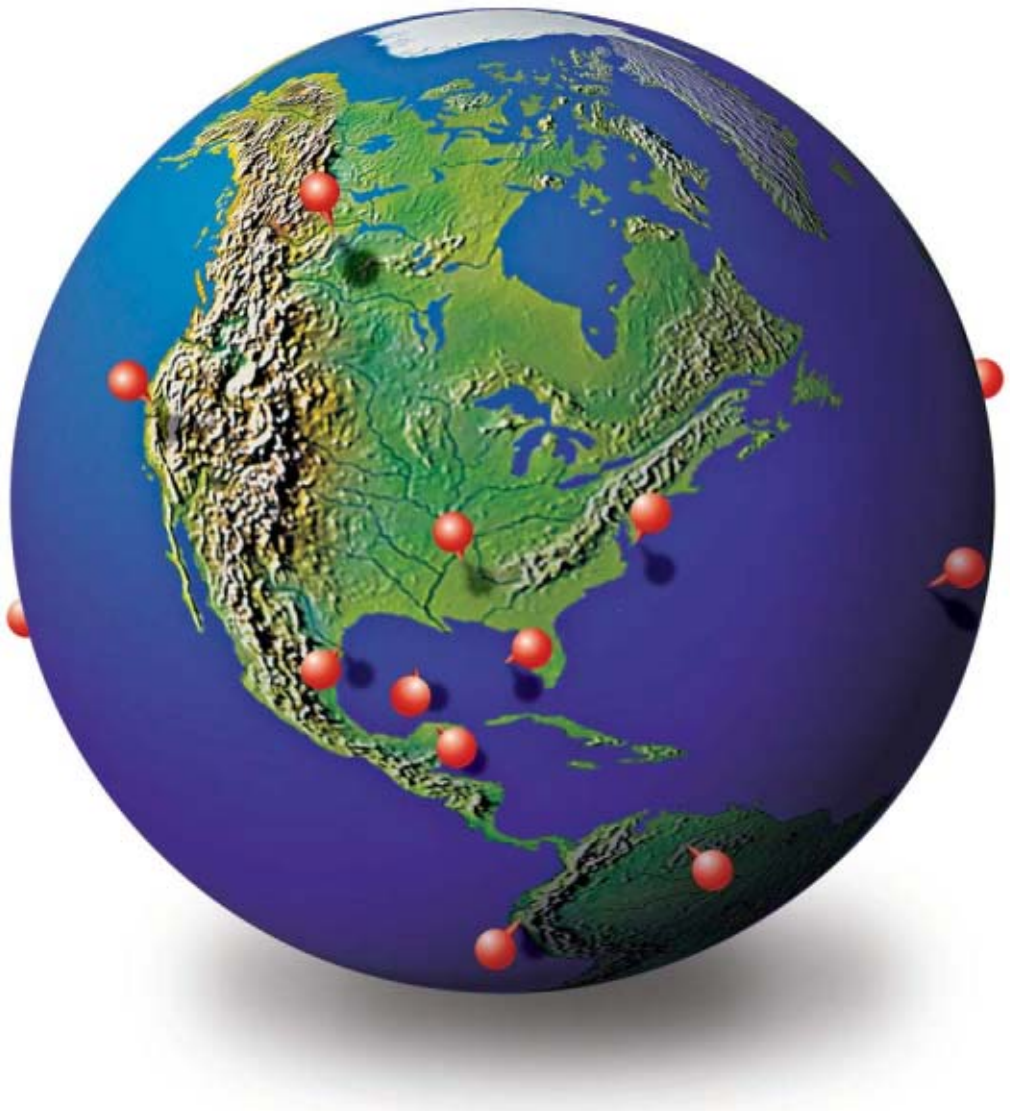
Hurricane Humberto

Hurricane Humberto surprised forecasters as it intensified quickly from a tropical storm to a hurricane while making landfall Sept. 13 at High Island, Tex. High winds snapped power lines in East Texas. The US Minerals Management Service said there were no reports of suspended oil or gas production or offshore evacuations because of Humberto. But three refineries in Port Arthur, Tex., lost power:

- A Shell Oil Co. spokesman said Sept. 17 workers restored power to most of Motiva Enterprises LLC's 285,000 b/d refinery in Port Arthur and began the restart sequence.
- Valero Energy Corp. said full power was restored to its 250,000 b/d refinery Sept. 14, and start-up was under way. Officials expected to return to normal production by Sept. 22.
- Total SA reported that partial power was restored to Total Petrochemicals USA's 231,252 b/d refinery late Sept. 13 and that it was expected to be back up within 5 days.

Temporary loss of three refineries stimulated market concerns over US fuel stocks, with crude inventories at the lowest level in 8 months and gasoline at the lowest position in 2 years. Analysts with the Societe Generale Group in Paris reported Sept. 17 that US oil inventories were still decreasing and that the promised increase of 500,000 b/d in production from OPEC is not big enough to prevent crude oil stock draws in the fourth quarter. "Markets worry about a worsening US economy that could hit demand. Oil analysts predominantly expect a decrease in the West Texas Intermediate price," they said.

(Online Sept. 17, 2007; author's e-mail: paulad@ogjonline.com; samf@ogjonline.com)



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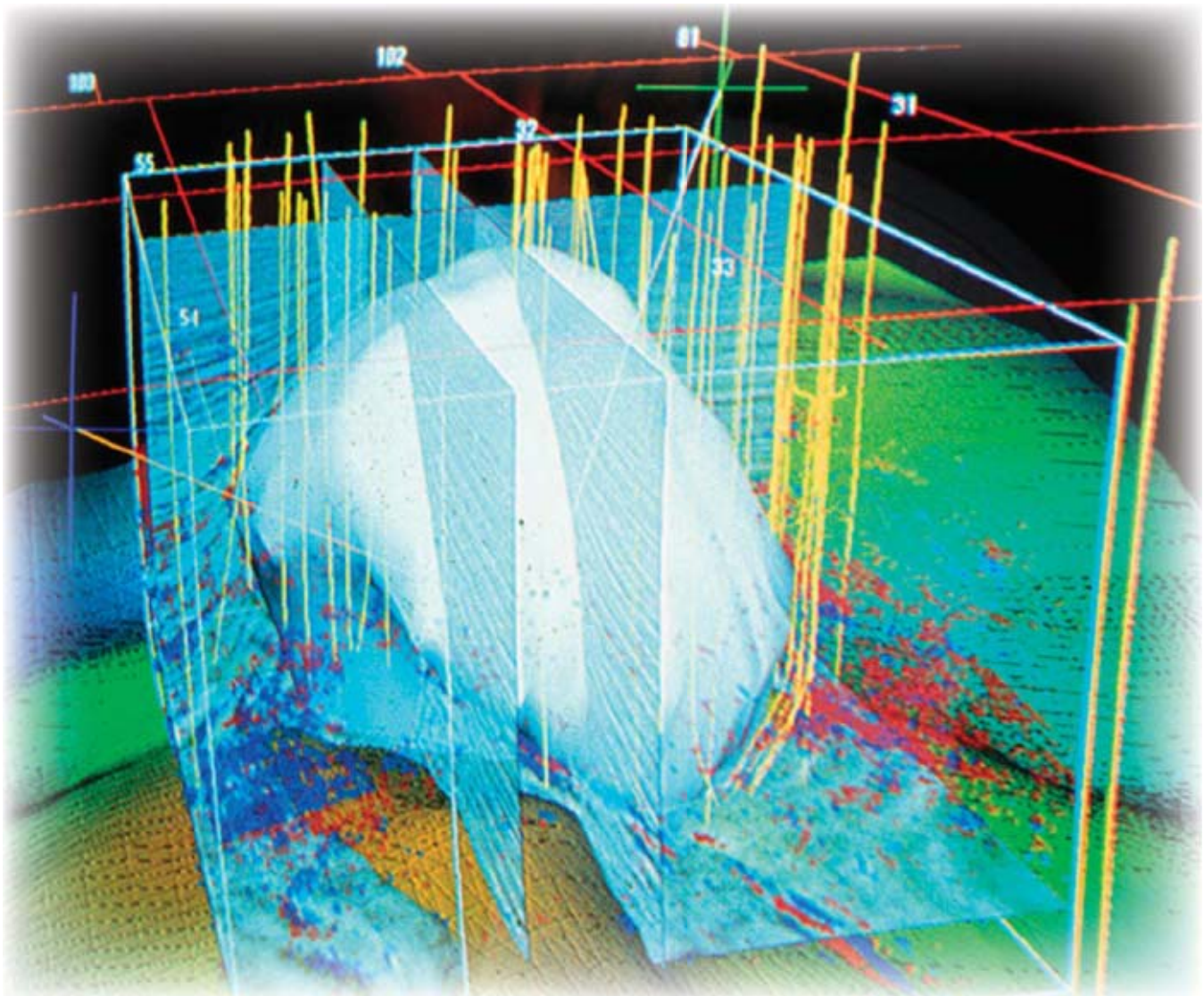

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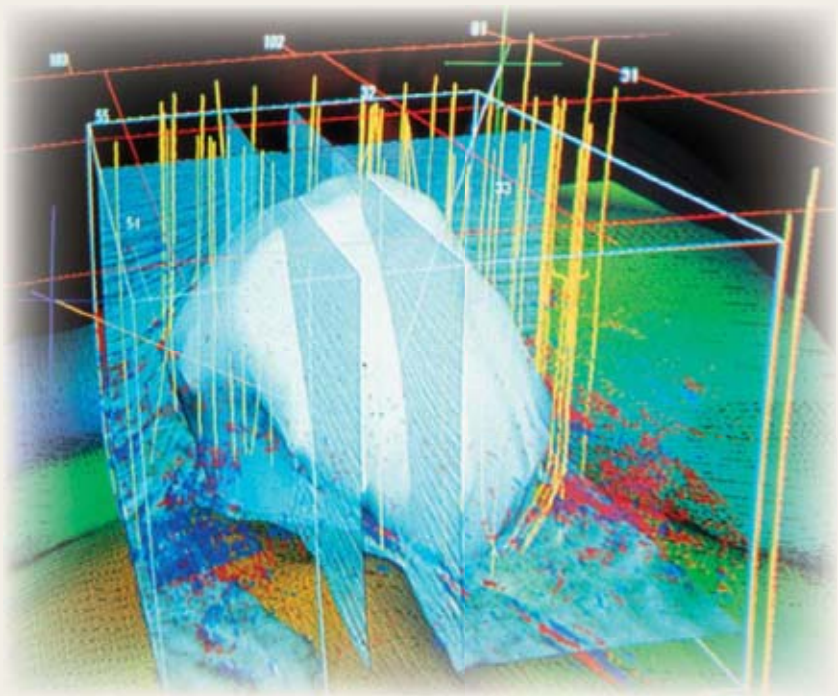

This image of a 3D visualization of subsurface features is courtesy of ConocoPhillips.

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Subsurface data technology advancing at dizzying pace

The dizzying pace of technology advancement in the oil and natural gas industry's ability to process, interpret, and image subsurface data shows no sign of letting up.

Innovations abound, from wide-azimuth 3-D surveys designed to image reservoirs below complex salt bodies, to new wireless land sensors engineered to capture the full 3-D waveform, to ultrafast migration algorithms to enable interactive modeling in time and depth domains.

> The most significant recent technology advances in subsurface data processing are the tools for integration and data mining that are applicable through the life of the field.
>
> — *Bill Schrom, Geotrace CEO*

An especially intriguing trend has been the industry move toward integrating seismic data with other kinds of subsurface data, helping operators to gain an even more comprehensive view of the subsurface.

Subsurface data processing

The most significant recent technology advances in subsurface data processing are the tools for integration and data mining that are applicable through the life of the field, according to Geotrace CEO Bill Schrom.

"Through technological convergence, linking seismic data to other subsurface measurements increases the accuracy and resolution of subsurface images," he says. "Historically, seismic data was the tool of exploration. As the demand for hydrocarbons has increased, improved exploitation of existing fields has come about through improved reservoir management. The goal of optimization has created a need for new tools that increase the accuracy of the subsurface imaging."

Among those tools Schrom cites are depth imaging, prestack seismic inversion, and pore pressure estimation.

He describes depth imaging as the technology to see the true geology below salt bodies or any abnormal velocity layers and adds, "Time image is imperfect because it is distorted, especially reserve time migration and prestack depth migration."

As for prestack seismic inversion, Schrom contends that the joint inversion of seismic and potential field data is emerging: "This inversion employs multiple input data types and potentially will make prestack inversion more robust, especially when well data are limited."

He points to Geotrace's RockRes simultaneous three-term pre-stack elastic inversion technology, which he says enables geoscientists "to more accurately predict lithology, fluid and, most importantly, the heterogeneity of internal rock property distribution of Vp, Vs, and density.

"If properly calibrated with other subsurface data (logs, cores, and production data), a 3D geobody ultimately can be extracted by multiple cutoff thresholds of most significant rock properties. Additionally, a static reservoir model with needed rock properties can be built for reservoir simulation and history match. When 4D or time-lapse 3D study is conducted, a dynamic reservoir can be created for optimum production."

With the advent of deepwater drilling, pore pressure estimation has become more sophisticated and has gone beyond traditional interval velocity to the compaction to pore pressure route, Schrom notes.

"Geotrace's high-density, high-resolution, high-order (HDHRHO) velocity analysis with anisotropy estimation provides the most critical 3D Interval Velocity Field (~geological velocity) at every sample and every common midpoint trace," he says. "For example, traditionally prestack time migration estimates velocity with a ¼-mile grid that only counts for approximately 5% of data acquired and severely underutilizes the seismic acquisition investment.

"Our calibrated pressure model is established with available subsurface data. It takes into account loading and offloading, burial depth, temperature, clay diagenesis, and lateral transfer and more accurately estimates HDHRHO 3D pore pressure volume, as well as other pressure attributes, such as overburden pressure, fracture gradient, and mud weights and stress for well planning and drilling hazards."

This allows engineers and drillers to plan ahead with a safety net during operation by providing an uncertainty fairway around the estimated pressure along the well path, Schrom adds.

Geotrace also offers the 3D Seal Capacity Cube (a slightly less dense pore pressure volume). This tool is used for seal integrity and hydrocarbon accumulation height evaluation in the framework of prospect and regional evaluation.

"The beauty of 3D pore pressure comes into play when corendering with other seismic attribute volume," Schrom says. "Geoscientists can quickly visualize and interpret 3D pressure cells for pluming and sinks to evaluate regional drilling risk and seal concerns assessment."

Jim Sledzik, marketing director for WesternGeco, contends that

"effective noise attenuation through digital group forming and 3D surface multiple attenuation has allowed us to clean the measurements in an unprecedented manner and therefore improve the quality of imaging or production monitoring in all types of environments."

Pete Bennion, vice-president, imaging, for TGS-Nopec, contends that the combination of a cost-effective computing environment using Linux cluster technology and high-speed disks has freed the software developers to enhance the precision of the algorithms and extend them while reducing turnaround.

"For example, 3D SRME [surface-related multiple elimination] has become standard over 2D SRME in the past 2 years despite the considerable computational effort," he says. "Velocity autopicking is another area where fast machines have proven effective. Tomography has now been generalized as a velocity refinement tool for depth imaging. All-azimuth tomographic ray-tracing is now feasible and better addresses the wide-azimuth acquisition techniques now being used in 3D marine. Subsalt tomography is a reality and is being used successfully in difficult salt canopy areas of the Gulf of Mexico. Alternative multiple elimination techniques such as wavefield extrapolation are showing promise."

Davey Einarsson, CEO of Calgary-based GSI, cites SRME as a breakthrough technology: "Multiple reflections are misleading, and we finally have the technology to remove them from the data volume, resulting in 'cleaner' data."

Ruben Martinez, PGS chief geophysicist for data processing, cites 3D wave equation prestack depth migration (PSDM) as a key recent advance in seismic data processing: "The accuracy of the wave equation-based methods [exceed] those based on Kirchhoff implementations because wave equation methods comprehend multivalued raypaths in the presence of complex geology and very complex velocity models."

Subsurface data interpretation

While acknowledging the sophistication and power of commercial software packages for seismic interpretation, Martinez contends that advances in interpretation are mainly related to the extraction of subsurface information not obviously seen in the seismic data when analyzed in an interpretation or visualization system.

"I am referring to the use of seismic attributes that can infer subsurface characteristics not seen in the conventional seismic data," he points out. "There are many attributes that, once analyzed and combined properly, can lead to very accurate interpretations of the subsurface and its contents. For example, coherency measurements may yield maps of fracture trends.

"Other advances are in the area of interpretive processing, such as acoustic impedance estimation and elastic inversion for P and S wave impedances from prestack data using [amplitude vs. offset] measurements. Maps of these estimates can be invaluable to interpret rock properties and to produce fluid content/type maps from 4D measurements."

A great step in data interpretation came with the automatic 3D volume interpretation of geologic bodies, stratigraphic sequences, and discrete fractures after image processing and gaming industry techniques were applied to seismic data, notes Sledzik: "Also, integrated 3D visualization of subsurface measurements and interactive modeling while interpreting have helped in better understanding the data and therefore in making better decisions when guiding or correcting an automatic interpretation."

He cites WesternGeco's i2i (interpretation to imaging) software. The software combines interpretation, processing, imaging, and specifically tomography through a permanently evolving earth velocity model.

There is now a much closer linkage between interpretation and imaging driven by the need to better understand the geology, notes Bennion, citing difficult subsalt areas.

"The ability to quickly view an interpretation and convert it to a new velocity model to be used in PSDM helps shorten the cycle time between generating the image and reinterpreting it," he adds.

Subsurface imaging

Continuing increases in computing power are removing many of the restrictions that resulted in the use of simplified earth models in seismic imaging and inversion algorithms, Sledzik contends.

"We are now seeing very impressive results when anisotropic elastic full waveform tomographic imaging and inversion algorithms are applied," he says. "And we are really just beginning to talk about true 3D subsurface imaging with the advent of rich- and wide-azimuth marine seismic acquisition techniques, and the integration of multiple geophysical measurements (seismic, borehole, electromagnetic, gravimetric) to delineate complex geological bodies such as salt."

The dramatic increase in computing power at lower cost has also accounted for the most significant recent technology advance in subsurface imaging, contends Bennion, noting that it allows the use of multiple algorithms in depth imaging.

"Kirchhoff can be used for steep dips and wide bandwidth, beam migration implementations are used for velocity model building due to their speed, wave equation is highly effective for subsalt imaging, and, finally, reverse time migration is making an appearance as today's ultimate imaging algorithm," he says. "Adding to this the ability to estimate and autopick anisotropy parameters epsilon and delta and run anisotropic PSDM now gives interpreters an added degree of confidence in the positioning of their prospect."

Einarsson concurs, noting that PSDM and prestack time migration "give a superior, unambiguous image of the subsurface. The availability of relatively inexpensive, large, fast computers makes this possible."

Martinez contends that although 3D traveltime tomography is not a recent velocity estimation method, the commercialization of the method has been impressive.

"Automated picking of depth residuals and dip fields has experienced important developments yielding a direct impact in turnaround time for processing very large data volumes," he says. "Also, the accuracy and effectiveness of the ray tracing and tomographic inversion have advanced significantly in robustness and algorithmic speed."]

New tools advancing subsurface data integration

Integration of seismic data with other subsurface data is benefiting from gains in computing power and development of new software tools.

With available prospects located in increasingly complex geologic environments, oil and natural gas operating companies that take advantage of those new tools will do a better job of finding and producing hydrocarbons.

Integration challenges

"Seismic and nonseismic data have been integrated from the first time a geophysicist used a copier to rescale a well log to overlay it on a seismic section," says Dan Piette, president and CEO of OpenSpirit Corp. "This is not an optional tool to find oil and gas but a necessary one."

In recent years, the ability to integrate these data has become easier, as software has become available to automatically perform the conversion between time and depth, and as depth-migrated seismic data has become more common, he notes.

Bill Schrom, Geotrace CEO, concurs: "The basic assumption is that traditional subsurface data (logs, cores, fluid types, pressure, temperature, production data, etc.) provide more accuracy and higher resolution. However, sparse and scattered surface seismic data are highly dense and spatially continuous but have a low resolution and are less accurate. Integrating those data gives the oil and gas industry the best of both worlds."

Piette contends that all operating companies must pursue a common integration framework on which to hang both their applications and their data: "The old days of proprietary data stores and stand-alone applications are going the way of the command line interface.

"If the petrophysicist comes up with the best interpretation in the world, but the geologist doesn't know where to put it, or the reservoir engineer doesn't know how to integrate it into his map, that work can just be thrown away. All companies need to have a strategy for integration that includes a services layer that takes care of the quality of the data, the translation of units and coordinate systems, and the integration of multiple vendor applications and databases. This software exists today, but is too often being bolted on at the end of the installation of a new application."

Piette urges operating companies to realize that an integrated solution doesn't just appear because data can be moved from one database to another: "It needs to be a thoughtfully approached solution that may not be cheap but will pay back its value many times over during the life of the installation."

One of the biggest challenges of such integration is simply knowing where those data are, Piette says.

"That means knowing not only where in the world (Gulf of Mexico, North Sea, etc.) the physical entity lies, but also where the digits themselves are stored. Are they stored on a local disk? A shared network disk? Offline storage? Network storage?

"Then the comfort that the data, once integrated, is in the same cartographic reference system (CRS) is critical to a successful interpretation. If you know where it is, but it is really loaded in a different CRS, then you are in the worst of all possible data worlds: You think something is right and trusted, and it is wrong, and all your subsequent decisions are tainted."

Piette points out that there are companies that provide the hardware and software needed to ensure the data are accessible and companies that can ensure the data are correct.

But the two companies are never the same, and the solutions provided need to be constantly monitored and managed to make sure that the results stay accurate, he insists.

"The bigger challenges will occur because the exploration companies need to find entirely new workflows that can take advantage of some of the new data that are available," Piette says. "You can look at the electromagnetic data that have never been available in the past except from a well log. Or gravity gradient data, which is extremely high-resolution potential field data that are being collected directly rather than being derived mathematically."

"No exploration manager has ever sat down and asked himself, 'So how do I increase my cycle time today?' But that question must be asked, because it does take more time to integrate in all these additional data. A tradeoff between accuracy and speed must be made."

New technologies

New technologies for integrating seismic and nonseismic data are proving effective tools for oil and gas companies that are scrambling to keep replacing reserves through exploration, development, and production.

"Integrating other subsurface data with 3D seismic data provides oil companies a calibrated high-density, high-resolution (HDHR) subsurface geological model with reservoir thickness/extent, reservoir heterogeneity, and rock/fluid properties for prospect technical evaluation and financial risk assessment," Schrom notes. "The key technologies for this calibrated HDHR geological model are: 1) lithology and fluid prediction using prestack seismic inversion, such as Geotrace's RockRes, for downscaling seismic resolution (more than tens of feet to log scale [~1 ft] and, eventually, core scale [<1 ft]) with petrophysical

analysis; and 2) pore pressure estimation in overburden, reservoir, and underburden, such as our Seal Capacity Cube and Pore Pressure Cube.

"This static HDHR geological model can be updated with 4D seismic, enabling historical production data and newly added subsurface controls for fluid movement to create a calibrated dynamic reservoir model. All available data are then mined for production efficiency."

This integrated approach provides operating companies with the technical power and knowledge database to create new plays in new geological basins for exploration, expand near-field plays in existing ventures for development and exploitation, and maximize production and optimize cash flow for mature fields, Schrom adds: "This produces a more diversified portfolio in E&P business and better profit predictability."

Interoperability remains one of the key technical challenges to integrating seismic and nonseismic data, notes Piette.

"New information technologies such as SOA (service-oriented architecture) allow for the easy integration of these new data from various disparate data sources. Energistics, the replacement for POSC, is pushing forward with new XML standards for our business," he says. "These include WITSML for well data and PRODML for production data. Both of these standards have the potential to ease the flow of data to applications."

Piette also notes that OpenSpirit donated its proprietary Units Catalog and Data Model to Energistics for use by the entire open-standards community.

Barriers

Companies that continue to put barriers to integrating seismic and other data will fall behind in the search for the oil and gas that is harder to find, Piette contends.

"Technologies (such as OpenSpirit) exist that allow for the transparent integration of seismic and well data to the desk of the end user," he says. "New technologies are being developed almost daily that exploit the research that is taking place around the industry.

> Companies that continue to put up barriers to integrating seismic and other data will fall behind in the search for the oil and gas that is harder to find.
>
> — *Dan Piette, CEO, OpenSpirit*

Will integrating/managing various types of subsurface data result in a new knowledge management paradigm that represents a step-change in imaging the subsurface, or is it really mainly a tool for increasing efficiency?

"There is no way of knowing what value will come from the true integration of multivariant data." Says Piette. "Even if the only value that comes is an increase in efficiency, the result will be well worth it for the industry."

He decries the fact that the oil and gas industry spends much less on information technology than other industries do—2% vs. 18% for the financial services industry, for example: "As more money is spent, the interaction between these different data types will become more apparent, and the value of this interaction will only increase."

Piette also worries about the reluctance of managers to make the investment necessary for open standards to work: "It is not as simple as installing a new firewall and then saying you are done. There is a huge change that needs to take place in the infrastructure, workflows, and data management processes to be successful."

Changing demographics will help erode that reluctance, Piette adds: "As younger people reach higher levels of responsibility within these companies, they will feel more comfortable making these investments. The YouTube, Facebook, and MySpace generation understand the value of social networks and fast-paced visual learning. It will be a different world in 20 years."]

R&D yielding advances in subsurface processing, imaging

Research and development continues to yield impressive advances in subsurface processing and imaging technology.

A host of new tools available to operating oil and natural gas companies is enabling them to gain unprecedented efficiencies in data processing and ever-sharper clarity and detail in imaging the subsurface.

Wide-azimuth

Over the past few years, the most significant advance in seismic data imaging resulted from the drive to gain the best subsurface insights possible from data acquired with the new technique of wide-azimuth acquisition, claims Peter Whiting, CGGVeritas executive vice-president, processing and imaging.

"When you look back at data processed 10 years ago and

> Over the past few years, the most significant advance in seismic data imaging resulted from the drive to gain the best subsurface insights possible from data acquired with the new technique of wide-azimuth acquisition.
>
> — *Peter Whiting, CGGVeritas*

compare it with recently imaged data, it becomes clear that advances can mean the difference between a dry hole and a discovery," he notes. "Sometimes these advances are slow and steady and other times, they are step-changes.

"The advent of wide-azimuth acquisition resulted in a step-change improvement in some of the most challenging areas to image seismically—as an example, beneath very complex salt bodies in the deepwater Gulf of Mexico."

Processing and imaging data acquired from wide-azimuth surveys has required a complete upgrade of the standard software tools, as well as significant enhancement to imaging algorithms, Whiting points out.

"CGGVeritas began acquisition of the first wide-azimuth survey in the deepwater Gulf of Mexico in 2004, and over the past 3 years, considerable investment and focus on processing and imaging wide-azimuth data has resulted in seismic images that are nothing short of stunning.

"In the complex geologic settings of the Gulf of Mexico, where imaging limitations previously created very high-risk profiles for prospectors, well-processed wide-azimuth surveys have unlocked new subsurface potential and are dramatically increasing interest in this potentially prolific basin."

Conventional 3D seismic surveys today, such as those collected with narrow-azimuth geometries, are sometimes insufficient to overcome challenges imposed by the subsurface geology, points out Ruben Martinez, PGS chief geophysicist, data processing: "All these challenges exist today, and wide/multi-azimuth surveys mitigate these problems," Martinez notes. "The inclusion of different azimuths during the data acquisition and the application of the correct data processing techniques yield results not seen otherwise with the conventional narrow-azimuth geometries or conventional 3Ds.

Martinez cites advantages of co-locating pressure and velocity sensors, such as with PGS's new dual-sensor streamer, which yields enhanced resolution and better penetration.

"We will see more and more wide/multi-azimuth surveys in the future. The extra cost is minimal compared with the percent of risk reduction obtained with this technology."

Reverse time migration

Reverse time migration (RTM) is an imaging technique based on the accuracy of the full two-way wave equation.

Although theoretically known for many years, computational intensity has kept it from being developed as a conventional processing option, notes Whiting.

"With the continued increase in computing capacity, CGGVeritas has developed and refined RTM so that it now a realistic option for obtaining superior images in complex areas with high dips and high frequencies," he says. "Further, since RTM is based on the full two-way wave equation, the amplitude integrity of the images is higher than that of previous imaging algorithms and hence offers the potential for improved fluid and rock property estimates in complex areas."

Martinez thinks that RTM will become the standard method for subsurface imaging: "RTM provides opportunities for improving the imaging accuracy not seen with conventional Kirchhoff or wave equation methods (one-way wave equation). RTM uses the two-way wave equation, and this provides the opportunity to reach geologic dips up to 90° or beyond."

> As data volumes continue to increase, the demand for improvements in imaging accuracy and reductions in turnaround time increase as well.
>
> — *Jim Sledzik, WesternGeco*

Prestack depth migration

As data volumes continue to increase, the demand for improvements in imaging accuracy and reductions in turnaround time increases as well, notes Jim Sledzik, marketing director for Schlumberger Ltd. unit WesternGeco.

"Recently, we have seen an explosion of prestack depth migration (PSDM) algorithms with more optimized computer operations and fewer earth model assumptions," he says. "Besides the now-classic Kirchhoff PSDM and one-way wave equation migration, there is now available a wide range of PSDM algorithms dealing with various levels of subsurface complexity, and various acquisition-related implementations with a broad range of computer cost and efficiency—from algorithms such as fast-beam up to elastic [RTM].

The ultimate goal with faster computers and algorithms, says Martinez, is that "real-time depth migration—with the updates coming from the well information as they are drilling—is going to be the future."

Controlled beam migration

Controlled beam migration (CBM) has been a breakthrough, primarily in imaging in the Gulf of Mexico but also in many other basins such as onshore US, offshore Vietnam, and offshore

Western Africa, according to Whiting.

"The specialized imaging algorithm produces much clearer images of subsurface reflectors in areas where standard imaging algorithms have struggled to produce anything reliable," he says. "CBM, combined with specialized algorithms for wide-azimuth data, forms a powerful combination for understanding reservoir potential.

"At CGGVeritas, we have seen CBM produce high-quality, unambiguous images below complex salt bodies. In offshore regions of Vietnam, CBM has produced reliable images of the fractures in the buried granitic basement that are critical for successful production."

Attenuation

A key new technology for improving attentuation is 3D surface-related multiple elimination (SRME).

For Whiting, 3D SRME provides the ability to attenuate some of the very troublesome and complex multiple events that tend to contaminate seismic images and obscure and distort the target events.

"At CGGVeritas, 3D SRME has been routinely used in recent times on very large surveys in most parts of the world, resulting in improved confidence in the interpreted estimates of the subsurface," he says. "Recently, CGGVeritas has reengineered 3D SRME for wide-azimuth geometry and has successfully applied it to several wide-azimuth surveys in the deepwater Gulf of Mexico.

Martinez thinks SRME technology will continue to show a lot of progress: "The evolution will be in SRME-type methods that are data-driven methods; this represents a tremendous advantage over other methods, like Radon, which require a preliminary knowledge of the velocity field."

Full-wave seismic

Full-wave seismic technology continues to mark progress with ever-increasing computational capacity and evolving multicomponent recording.

"Recording full-wave seismic, with over/under streamers or multicomponent receivers, requires adequate processing and imaging algorithms," notes Whiting. "WesternGeco has an advanced imaging workflow, which includes model building, PP-PS joint tomography, and elastic migration."

Martinez points out that the accuracy of four-component (4C) data is constantly improving—for example, PGS recently introduced the OptoSeis fiber optic permanent seabed 4D4C monitoring system.

"In data processing, the elusive goal continues to be the use of the elastic wave equation," he says. "The barrier is not that the theory is unknown but that the algorithms are still expensive to run with today's computer power. But until that happen, acceptable approximations in the algorithms are in use and giving results."

Martinez speculates full wavefields will be used to image the subsurface in the future.

"By full wavefields I mean elastic wavefields and not only acoustic," he clarifies. "To achieve this task, imaging methods that make use of the elastic wave equation will be in place and will include most, if not all, modes of wave propagation. Hopefully, the computer capacity will be there to be able to produce these images commercially."

4D/real-time monitoring

The advent of 4D, or time-lapse, seismic has given the industry the capability of real-time monitoring of the subsurface.

Whiting notes that CGGVeritas has seen 4D seismic technology quietly growing to become a trusted and required tool for optimizing reservoir production.

"SeisMovie, a CGGVeritas high-resolution, high-sensitivity 4D reservoir monitoring solution using permanent arrays of sources and receivers, which operate continuously, has been applied successfully to a range of scenarios, including heavy oil production and gas storage monitoring," he says..

Sledzik notes that the biggest impact of 4D comes in the area of seismic data acquisition, but adds, "What could potentially change the game here is the integration of processing and interpretation capable of efficiently handling multiple data volumes and the utilization of 4D measurements to discover geomechanical information about the evolution of the field."

The ultimate goal in 4D seismic is to deliver the 4D seismic anomalies map with a fast turnaround so that the seismic information can be incorporated into the reservoir simulation process, contends Martinez.

"The turnaround time improvement can have a significant impact in the placement of the production wells to be drilled during the field's exploitation phase," he says. "Therefore, advances in seismic data processing with the aim of improving the turnaround time is vital to make 4D a fully accepted exploitation tool in the arsenal of the reservoir engineer's tools. Automating the processing steps is the main challenge to date."

> The close linkage of interpretation with imaging blurs the lines between these disciplines: "The latest systems allow viewing of multiple attributes that add a new dimension to the analysis of seismic data."
>
> *— Pete Bennion, TGS-Nopec*

Visualization

Improvements in 3D visualization have been a key enabler in measurement integration, according to Whiting.

"We have now gone one step further to using 3D visualization as an enabler for work flow integration," he says. "We have achieved this by visualizing and manipulating together the data getting in and being produced during the stages of interpreta-

tion, processing, and modeling to imaging."

Pete Bennion, vice-president, imaging, for TGS-Nopec, thinks that the close linkage of interpretation with imaging blurs the lines between these disciplines.

"The latest systems allow viewing of multiple attributes that add a new dimension to the analysis of seismic data," he says. "The ability to very rapidly and efficiently look at the underlying gather data contributing to a stack trace within a 3D cube gives the interpreter powerful analysis tools to validate potential prospects."

Martinez cites a key advance in the orders-of-magnitude improvement in computer processing capabilities, specifically "the ability to utilize more than one graphics card at once to drive one screen—even using four graphics cards as a computer bank to give the user access to what considered to be supercomputer performance just years ago on his own desktop."

Model building/validation

Model building—and its validation—is one of the bottlenecks in the depth imaging process, according to Martinez.

"The standard in the industry today is the utilization of traveltime tomography," he notes. "There are still challenges to overcome in tomography, but they are mainly related to the automation of the process.

"In the near future, we expect that the wave equation-based tomography (WE tomography) methods will gain popularity as they offer advantages over the traveltime tomography methods; the WE tomography methods do not require the intensive picking of residuals and geologic dips as does the traveltime tomography. Therefore, the WE tomography will offer better automation and better turnaround time of the velocity model to be used in depth migration."

WesternGeco's model-building capabilities include handling complex, hybrid earth models (combination of sharp-smooth geometrical representation) in both the model building step, as well as in tomographic inversion, notes Sledzik: "For resolving shallow subsurface anomalies, we use seismic diving wave tomography. For complete earth model, we use seismic reflection tomography. We have now started to use CSEM (controlled-source electromagnetic) inversions.

EM

Electromagnetic (EM) methods have evolved beyond the shallow subsurface, notably with seabed logging.

One advocate of seabed logging is Terje Eidesmo, CEO of Norwegian contractor ElectroMagnetic GeoServices (emgs).

"Until seabed logging came along, oil companies had to drill these wells on the basis of a single measurement: acoustic impedance derived from seismic," he notes. "Today, they can build earth models based on a second measurement: resistivity derived from seabed logging. Furthermore, resistivity is more likely to provide information directly about pore fluids. Even where resistivity is driven by the rock matrix (carbonates, volcanics, etc.), it can provide valuable information for unraveling the real geology in many areas."

"The greatest value [in seabed logging] may lie in rapid electromagnetic scanning of frontier areas, which we see is being used more and more widely by the oil companies. This will identify reserves earlier in the E&P cycle and enable us to focus resources more effectively, but it will also uncover new reserves in unconventional traps that can be hard to identify from seismic data alone."

— Terje Eidesmo, emgs

Although seabed logging has already become a routine part of the E&P workflow at most leading oil companies, the technique is still in its infancy, Eidesmo points out: "There are still huge leaps to be made in unlocking the full information content of the full vector wavefields—electric and magnetic.

"As EM sampling densities increase, new processing techniques emerge, and equipment performance continues to improve, seabed logging will provide increasingly detailed reservoir characterization information and even time-lapse data."

Seabed logging today is being used primarily to reduce drilling risk in prospects identified on seismic and to provide improved salt body definition to enhance subsalt seismic imaging, says Eidesmo.

"However, we think that the greatest value may lie in rapid electromagnetic scanning of frontier areas, which we see is being used more and more widely by the oil companies," he contends. "This will identify reserves earlier in the E&P cycle and enable us to focus resources more effectively, but it will also uncover new reserves in unconventional traps that can be hard to identify from seismic data alone."

Martinez sees step-changes in the technology used for EM acquisition, citing marine EM solutions where both the source and recording device are towed.

"Such operations could be conducted with close to the same efficiency as seismic operations and possibly enable acquisition of EM measurements from the same platform as used for seismic data," he says. "EM technology is today at a very early stage, and we expect significant developments on acquisition, processing, and interpretation to take place over the next couple of years. If successful, the technology PGS is currently developing could represent a quantum leap in EM technology, since a towed system could be more than 10 times more efficient than current technology."

Martinez points out that the accuracy of four-component (data) is constantly improving—furthered, for example, by the recent introduction of fiber optics and node technology.

— *Ruben Martinez, PGS*

Reservoir geophysics

Reservoir geophysics is a discipline within geophysics that continues to gain momentum, notes Martinez.

"The need to translate seismic information into rock properties and then translate these into lithology and fluids estimates has produced an important evolution in reservoir geophysics," he says. "Techniques such as seismic inversion, amplitude vs. offset, elastic inversion, and seismic attribute analysis improve continuously to provide the link between seismic data and reservoir properties."

Another reason to expect reservoir geophysics to greatly advance in the future is that it is required for a reliable understanding of 4D and 4C measurements, Martinez adds.

The future

Whiting foresees significant improvements continuing in the quality of subsurface images and subsurface property estimation.

"The wide-azimuth surveying technique will undoubtedly result in further refinements and provide even more reliable and extensive images of the subsurface," he says. "Advances in computing (potentially spurred by advances in nanotechnology) will allow for higher-fidelity processing than can be considered today. The quantitative accuracy of the processed wavefield will lead to highly reliable estimates of subsurface rock and fluid properties.

"Acquisition advances in seafloor techniques and permanent monitoring will lead to an inexorable link between seismic information and successful exploitation of reservoirs. Advances in multicomponent acquisition and processing will further improve the industry's understanding of subsurface rock and fluid properties, as well as fracture and stress information.

"Nearer-term advances at CGGVeritas, along with increasing computing power, will continue to improve our ability to process full wavefields (even more than one wavefield at the same time). This will lead to highly accurate and precise velocity models of the subsurface and correspondingly improved depth images.]