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Production Report

US gas market responds to hurricane disruptions
Flow test buttresses estimates of gulf's Lower Tertiary potential
CGES: Global crude supplies will continue to get heavier
Method helps pool multisource pipeline failure rate data

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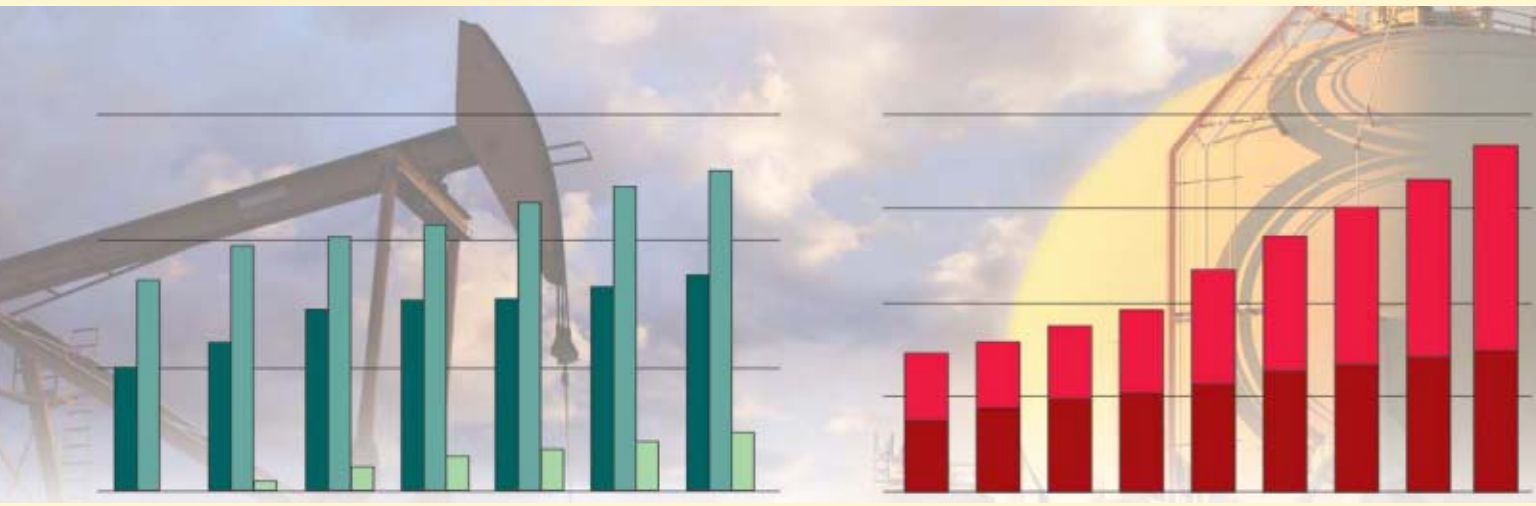
Sept. 25, 2006
Volume 104.36

PRODUCTION REPORT



REGULAR FEATURES

COVER

The steam generators shown on the cover provide steam for producing the bitumen from Petro-Canada's MacKay River field in Alberta. The field is the industry's second full-scale steam-assisted gravity drainage project, with production starting in 2002. The first article in the Production Report, p. 39, discusses Alberta's bitumen reserves and production estimates and some of the many projects slated to come on stream in the next few years. Photo from Petro-Canada.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 47 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $49, 2 yr. $75, 3 yr. $99; Latin America and Canada: 1 yr. $54, 2 yr. $90, 3 yr. $125; Russia and republics of the former USSR, 1 yr. 500 rubles; all other countries: 1 yr. $99, 2 yr. $165, 3 yr. $240, 1 yr. basic digital $49 worldwide, 1 yr. premium digital $79 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 104, No. 36) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

PennWell, Houston office

1700 West Loop South, Suite 1000, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com
Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration G. Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Associate Editor Judy R. Clark, judyrc@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor Leena Koottungal, lkoottungal@ogjonline.com
Associate Editor Angel White, angelw@pennwell.com
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office

1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290
Presentation/Equipment Editor Jim Stilwell, jims@ogjonline.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Alana Herron, Kermit Mulkins, Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

Washington

Tel 703.963.7707
Washington Correspondent Nick Snow, nsnow@cox.net

Los Angeles

Tel 310.595.5657
Senior Correspondent Eric Watkins, hippalus@yahoo.com

OGJ News

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Subscriber Service

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

PennWell Corporate Headquarters

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FracDoor® Sleeve Lets Anadarko Independently Fracture Three Zones in One Day

The Challenge:

Alberta, Canada — Anadarko Canada Corporation wanted to independently fracture an upper and lower Dunvegan formation and a Doe Creek formation in a 1,350-meter well, without removing the completion and production assembly from the hole. This procedure would prevent wellbore fluid from coming in contact with the perforations after fracturing and create the best possible flowback during the well's testing and production stages.

The Solution:

To allow three fracturing jobs to be performed in one day while maintaining zonal isolation, Halliburton recommended its **FracDoor®** ball-actuated **Sliding Side-Door®** circulation and production sleeves. Halliburton's FracDoor sleeve allows selective multi-zone stimulation operations through the production string by dropping or pumping a selective ball prior to zonal stimulation. As part of the job, one FracDoor sleeve would be placed on the completion string between the packers, and a second sleeve would go above the top packer.

"The FracDoor tool worked extremely well. The ability to fracture three zones independently on the same day saved us significant mobilization, testing and cleanup costs. Also, not having to trip pipe in each zone was a significant factor in completing what were formerly marginal zones."

David Ramsden-Wood
Anadarko Canada Corporation

The Results:

The Dunvegan and Doe Creek formations were commingled and produced at approximately 1.6 million cubic feet per day. The economic value created was $110,000, based on savings to Anadarko from using the Halliburton procedure. "The FracDoor tool worked extremely well," said Anadarko's David Ramsden-Wood. "The ability to fracture three zones independently on the same day saved us significant mobilization, testing and cleanup costs. Also, not having to trip pipe in each zone was a significant factor in completing what were formerly marginal zones."

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Performance Profile 97

OGJ Newsletter

Sept. 25, 2006

International news for oil and gas professionals
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General Interest — Quick Takes

BP seeks DOT nod to resume Alaska production

BP PLC submitted an application Sept. 13 to the US Department of Transportation requesting authorization to resume production in the Eastern Operating Area (EOA) of Prudhoe Bay for the purposes of pigging.

"Although this is an encouraging development, it is the first step of many," BP said. "Work continues on a number of bypass projects, and we expect these to be ready by the end of October. BP has also committed to completely replace 16 miles of Prudhoe Bay OTLs [oil transit lines] this winter."

Meanwhile, Prudhoe Bay's production is up to about 250,000 b/d. Part of the field has been shut-down since early August because of severe corrosion problems discovered in OTLs.

Inspection of the integrity of the OTLs in Prudhoe Bay continues to advance. BP has completed more than 6,662 ft (26%) of ultrasonic (UT) inspections in the EOA. The company excavated three caribou crossings and a number of culverts for additional Western Operating Area (WOA) inspections.

Inspections have restarted in the WOA after the completion of the first tranche of asbestos-handling training for UT and insulation stripping crews. More than 5,813 ft (23%) of UT inspections has been done in the WOA.

"In both EOA and WOA inspections, our results continue to show no significant anomalies have been found, outside of those identified in the original pig run," the company said.

Saudi oil minister warns of tight refining capacity

Saudi Arabia's oil and gas investments will total some $70 billion during the next 5 years, said Saudi Minister of Petroleum and Mineral Resources Ali I. al-Naimi in a speech in Vienna Sept. 12.

Speaking before an Organization of Petroleum Exporting Countries international seminar, Al-Naimi said meeting global oil demand will require timely downstream investments.

"The industry must deal with a stretched refining system and match refining capacity to the anticipated future slate of crude oil that is becoming heavier and more sour, as well as attend to the infrastructure bottlenecks in pipelines, terminals, shipping, and critical sea channels," he said.

Al-Naimi said Saudi production capacity is estimated to reach 12.5 million b/d by 2009 compared with 11 million b/d earlier this year. The Kingdom is experiencing a drilling surge (OGJ Online, Apr. 16, 2006).

Saudi Arabia's downstream investments include the construction of two grassroots joint-venture export refineries, each with a capacity of 400,000 b/d.

One will be in Jubail on the kingdom's east coast and the other in Yanbu on the west coast. Saudi Arabia also plans to expand its Ras Tanura refinery, possibly transforming it into an integrated refining and petrochemical complex (OGJ, Feb. 13, 2006, p. 24).

Bolivia's oil minister resigns amid conflict

Bolivia Oil Minister Andres Soliz has resigned in the wake of a disagreement with Brazil's state-run Petroleo Brasileiro SA (Petrobras). Soliz had led efforts to nationalize Bolivia's oil and gas operations.

Soliz resigned Sept. 15, the day after Bolivian Vice-President Alvaro Garcia Linera said Bolivia was suspending a measure that would have exerted majority controlling interest in the operations of international companies working in Bolivia.

On Sept. 13, Soliz had issued the measure, which consequently prompted Petrobras Chief Executive Sergio Gabrielli to cancel a trip to Bolivia.

The measure would have reduced Petrobras's profit margins at two refineries and given Bolivian state-owned energy firm Yacimientos Petroliferos Fiscales powers to set domestic fuel prices (OGJ Online, Sept. 14, 2006).

Russia to boost oil exports to Asia-Pacific

Russian President Vladimir Putin said a much greater percentage of his country's oil exports will be heading to Asia and the Pacific in the next decade as part of a strategy of diversified marketing aimed at creating energy security for producing countries.

"We hope and we plan to increase our energy supplies to Asia and the Pacific from the current 3% of the country's oil exports to at least 30% of the overall energy exports in 10 years' time," Putin told the Group of Eight countries' parliamentary speakers in Sochi, Russia, Sept 17.

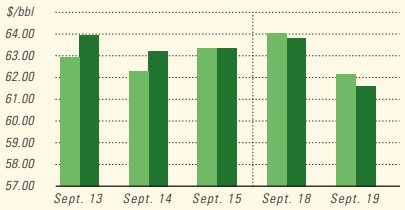
"We are to accomplish two major transport projects to deliver natural gas to China in this direction," Putin said. He added, "Russia has been consistently diversifying energy export routes and consequently has been working to make energy exports more reliable."

He said the strategy had initially met with resistance, but that everyone now agrees that energy security means "not only security for consumers, but also security for producers." He added, "Only if we take due account of each others' interests will we be able to attain a positive effect."

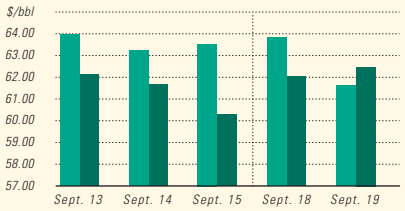
Putin said construction of the North European Gas Pipeline, agreed to in early September, also forms part of his country's strategy of energy security. ✦

Industry Scoreboard

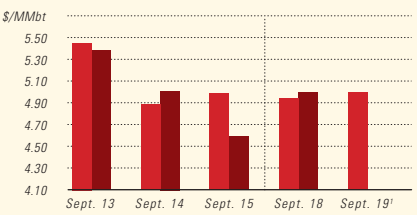
IPE BRENT / NYMEX LIGHT SWEET CRUDE



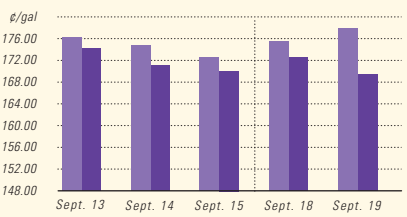
WTI CUSHING / BRENT SPOT



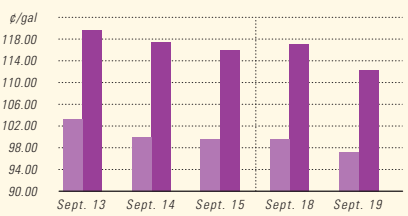
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



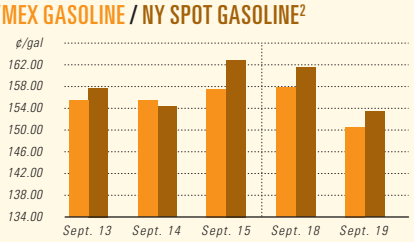
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE²



¹Not available.
² Nonoxygenated regular unleaded.

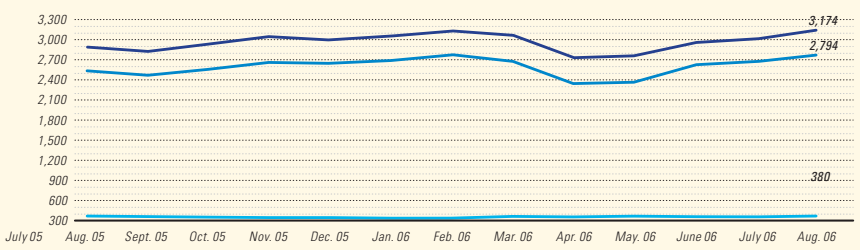
US INDUSTRY SCOREBOARD — 9/25

Latest week 9/15	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average	YTD avg. year ago*	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,809	9,156	7.1	9,748	9,126	6.8
Distillate	4,178	4,049	3.2	4,084	4,099	–0.4
Jet fuel	1,628	1,627	0.1	1,603	1,620	–1.0
Residual	622	1,027	–39.5	776	891	–12.9
Other products	5,211	4,811	8.3	4,916	4,903	0.3
TOTAL DEMAND	21,448	20,670	3.8	21,126	20,638	2.4
Supply, 1,000 b/d						
Crude production	5,082	4,706	8.0	5,098	5,278	–3.4
NGL production	2,391	1,585	50.8	2,200	1,768	24.4
Crude imports	10,843	9,649	12.4	10,233	10,066	1.7
Product imports	3,353	3,695	–9.3	3,486	3,295	5.8
Other supply[2]	1,025	992	3.3	1,081	1,272	–15.0
TOTAL SUPPLY	22,694	20,627	10.0	22,098	21,679	1.9
Refining, 1,000 b/d						
Crude runs to stills	15,990	14,740	8.5	15,152	15,420	–1.7
Input to crude stills	16,438	15,028	9.4	15,560	15,697	–0.9
% utilization	94.9	87.7	—	90.5	91.7	—

Latest week 9/15	Latest week	Previous week*	Change	Same week year ago*	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	321,210	325,282	–4,072	305,076	16,134	5.3
Motor gasoline	213,686	213,237	449	200,563	13,123	6.5
Distillate	147,567	143,661	3,906	133,056	14,511	10.9
Jet fuel	40,106	39,915	191	38,952	1,154	3.0
Residual	43,647	43,745	–98	33,048	10,599	32.1
Futures prices[3]						
Light sweet crude, $/bbl	63.57	67.42	–3.85	63.86	–0.29	–0.5
Natural gas, $/MMbtu	5.31	5.86	–0.54	11.09	–5.78	–52.1

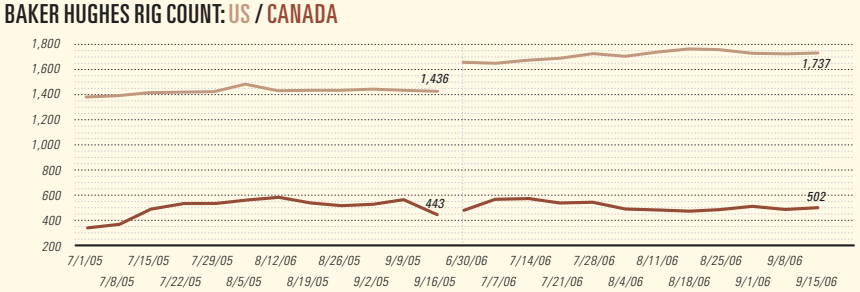
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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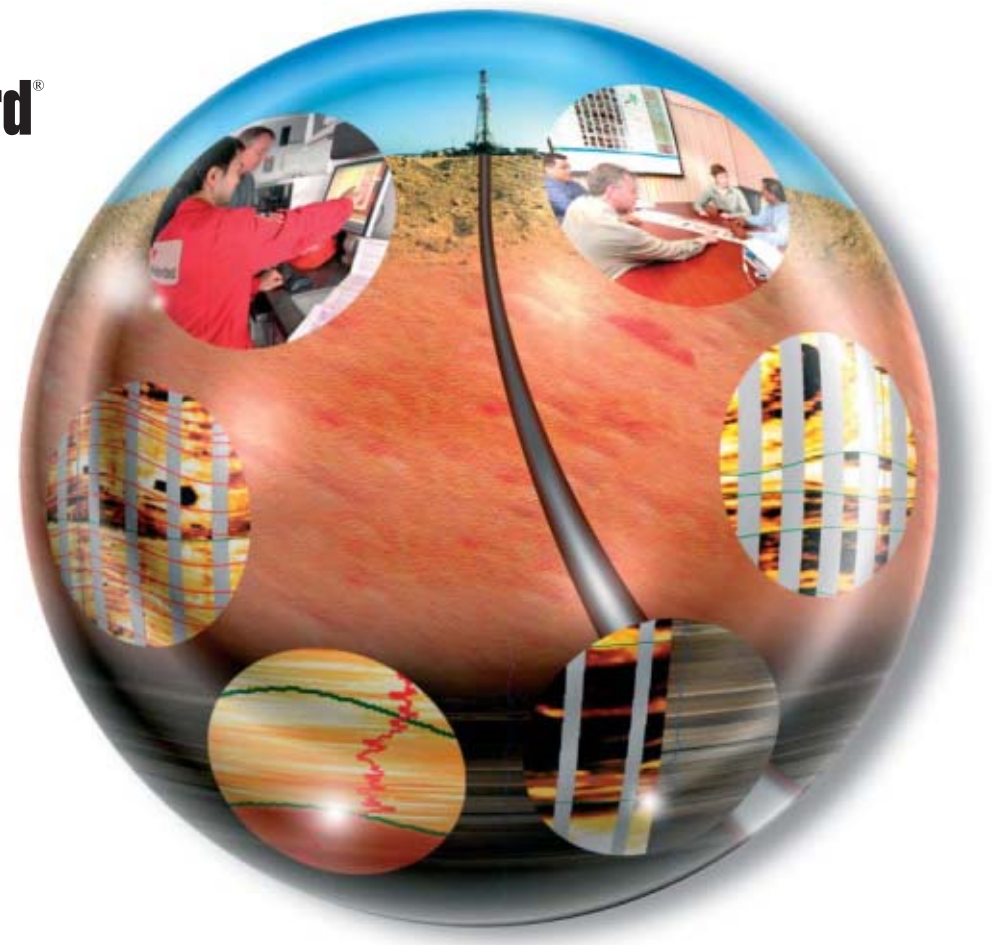

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Exploration & Development — *Quick Takes*

DNO prepares to start oil production in Iraq

DNO ASA, Oslo, is planning early production, possibly in first quarter 2007, from Tawke oil field in the northern Kurdish region of Iraq based on test results from the discovery well and an appraisal well.

DNO achieved a maximum flow rate of 5,000 b/d of oil during open-hole tests of Tawke-1A, a twin well 20 km from the Tawke-1 discovery well. Tawke-1 also flowed at 5,000 b/d on test (OGJ Online, June 19, 2006, Newsletter). This well penetrated two reservoir zones exceeding 2,000 m deep, which were preserved behind casing and will be tested later.

DNO said all major facilities are secured, and it expects the development plan to be finalized and presented soon to partner Kurdistan Regional Government.

Tawke-1A was drilled in open-hole mode to retest the shallower reservoir sections of less than 1,000 m because it is assumed that formation damage during installation and casing in the discovery well may have restricted oil flow.

The tests results, which were not conclusive, will be further investigated, and additional tests of the intervals are planned in Tawke-2, a stepout well 2 km west of the Tawke discovery. When conducting Tawke-2 tests, a more extensive acid stimulation and fracturing of the reservoir sections will be considered, DNO said.

Tawke-2 will penetrate only the shallower reservoir sections. It will be followed by the drilling of an exploration well in the eastern part of the Tawke area. DNO is performing a 3D seismic survey across the area as part of a program to assess the area's full oil potential.

Aramco discovers gas with Kassab-1 well

Saudi Aramco has reported a gas discovery in Saudi Arabia's Eastern Province 50 km south of its giant Ghawar field and 220 km southeast of Riyadh.

The company said its Kassab-1 well flowed on test at 16.2 MMscfd on a 44/64-in. choke at a wellhead pressure of 1,520 psi.

Kassab-1 was tested on Aug. 7 at 15,750 ft in the Lower Devonian Jauf sandstone reservoir underlying the prolific Upper Permian Khuff reservoir.

Pre-Khuff formations at 11,000-17,000 ft are among the major gas-bearing reservoirs in Persian Gulf countries. The Jauf reservoir has permeability and porosity variations with varying amounts of framework and pore lining clay. It exhibits unconsolidation intermingled with consolidated sandstone. The high-permeability layers have excellent flow capacities, Saudi Aramco says. Jauf reservoir sandstones primarily are of quartz with some feldspars such as orthoclase and microcline in some sandstones (OGJ, May 10, 2004, p. 35).

Saudi Arabia, which has one of the world's largest gas reserves, is pursuing an aggressive natural gas development program, tapping nonassociated gas reserves, particularly in the greater Ghawar field area, to meet a strong domestic demand for gas.

Tullow advances UK North Sea redevelopment

Tullow Oil PLC completed the Ketch 7 development well in the Schooner-Ketch redevelopment in the UK North Sea. On test, Ketch 7 flowed at 45 MMscfd of gas, and the company expects production in early October.

The horizontal well, spudded on June 2, encountered 540 ft of net pay along with higher-than-expected reservoir pressures. The addition of Ketch 7 is expected to increase the production capability of Schooner and Ketch fields to more than 100 MMscfd of gas.

Other Ketch wells are expected to generate additional production. Tullow spudded the 3,000 ft horizontal Ketch 8 well on Sept. 18.

Meanwhile, the NW Schooner appraisal well, targeting an extension of Schooner field, encountered a net gas pay of 275 ft. The well is being completed for testing, expected at the end of September.

If the test yields commercial flow rates, the well will be suspended, and the pipeline laid for tie-in to the Schooner platform in mid-2007.

Tullow owns 100% of Ketch 7 and 90.35% of the Schooner NW appraisal well. The company acquired Ketch and Schooner fields in early 2005.

Statoil find could drive LNG plant expansion

The Statoil ASA-led Snøhvit consortium is planning to drill additional wells in the Barents Sea next year and in 2008 to seek additional gas reserves for a possible future expansion of the Hammerfest gas liquefaction plant at Melkøya in northern Norway.

The plans follow a small gas discovery on the Tornerose structure that the company finds "encouraging."

Although Tornerose reserves alone would not provide enough gas for expanding the LNG plant, the discovery "marks an important stage in efforts to enlarge the resource base in the area," said Tim Dodson, Statoil's senior vice-president for exploration on the Norwegian continental shelf.

"The Tornerose discovery confirms that we're heading in the right direction," he said. The structure, which Dodson calls viable, "strengthens opportunities for expanding the Snøhvit gas liquefaction facility at Melkøya."

Statoil said Transocean Inc.'s Polar Pioneer semisubmersible rig drilled exploration well 7122/6-2 on production license 110B in 408 m of water and proved gas in several sandstone layers from the late-Triassic.

The well was drilled to 3,057 m TMD below sea level about 60 km east of Statoil-operated Snøhvit field and 100 km northwest of Hammerfest.

Petrobras-led group to explore off Argentina

Petróleo Brasileiro SA subsidiary Petrobras Energía SA, Argentina's Energía Argentina SA (Enarsa), and Madrid-based Repsol YPF SA agreed Sept. 12 to form a consortium to explore, develop, and commercialize oil and natural gas on Argentina's deepwater continental shelf.

Petrobras Energía, holding a 35% interest, will serve as operator, while Enarsa will hold 35% of the venture, and Repsol YPF 30%.

The consortium plans to conduct exploration activities in 200-3,000 m of water about 250 km off the city of Mar del Plata, Buenos Aires.

Last January the same group entered into an agreement with Petrouruguay SA, for exploration off Argentina in 150-1,500 m of water in the areas of ENARSA-1 (E1) and CCM2. ✦

Drilling & Production — *Quick Takes*

Repairs delay Thunder Horse production start-up

BP PLC plans to retrieve and rebuild all seabed production equipment from Thunder Horse field in the deepwater Gulf of Mexico following a series of tests in 4 months that showed metallurgical failure.

Consequently, BP does not expect production from Thunder Horse to begin before mid-2008. The company said it's too early to estimate the additional costs.

The original projected start up was for late 2005, but it has been pushed back as BP has resolved "many technology gaps" that emerged during development, a spokesman said.

Thunder Horse field was discovered in 1999. The project involves some of the highest-temperature, highest-pressure wells in the gulf.

The semisubmersible platform weighs more than 50,000 tons and is designed to process 250,000 b/d of oil and 200 MMscfd of gas. BP operates the development, owning 75% interest, and ExxonMobil Corp. owns the remaining interest.

The platform had to be restored to normal trim last year. That incident is unrelated to the latest subsea equipment issues, BP said (OGJ, July 25, 2005, Newsletter).

The drilling, production, and quarters platform on Mississippi Canyon Block 778 in the Gulf of Mexico, 150 miles southeast of New Orleans, was discovered listing 20-30° after Hurricane Dennis passed through the area (OGJ Online, July 12, 2005). The platform is moored in 6,050 ft of water.

The metallurgical problems became evident when BP conducted precommissioning tests by pumping water through the system to establish its integrity. The equipment passed all normal industry standard tests and regulatory requirements, but during more-rigorous and prolonged testing, a failure occurred on a subsea weld.

Consequently, BP opted to retrieve both the damaged seabed manifold and a second manifold for additional examination and testing. The second manifold displayed a similar failure during testing last week, BP said Sept. 18.

Bankers to study Albanian EOR pilot project

Bankers Petroleum Ltd., Calgary, reported it will begin a study for a thermal enhanced oil recovery (EOR) pilot project in Albania's Patos Marinza field.

A specialized EOR team has initiated the evaluation, economic analysis, and modeling of a thermal pilot project for the southern part of the field.

Under the current development plan, the life of Patos Marinza field is estimated at 25 years, which represents a total incremental oil recovery of 5-6%/year of the total field resources of 2 billion bbl of OOIP.

Total field recovery utilizing primary production techniques is thus estimated to be 10-12%, including the previous production by state-owned Albpetrol.

In Albania, the company this year has focused on continuing to build production through the takeover and redevelopment of wells from Albpetrol.

To date, Bankers's activities have increased current production to 4,200 b/d of oil. The company's goal is to reach 10,000-15,000 b/d of oil production in 3-4 years.

While EOR recovery techniques have been shown to have the ability to improve oil recoveries to 20-40%, it is not known at this time what the total potential impact could be on Bankers's Albanian reserves.

JED wins 20-acre Jonah/Pinedale spacing

JED Oil Inc., Calgary, and JMG Exploration Inc., with which JED is pursuing a merger, said they can drill as many as 32 additional wells on JED acreage in the Pinedale/Jonah area of Wyoming under a density ruling by the Wyoming Oil and Gas Conservation Commission.

The commission approved a request to change to 20-acre from 40-acre well spacing in the Green River basin area.

In August, JED said it had drilled two gas wells in the Pinedale area.

In the first well, JED fracture-stimulated 24 pay zones in 11 stages and encountered water in two of the stages. It was isolating the water zones and preparing the well for production from the six higher frac stages.

JED recently was completing and fraccing the second well, which also encountered multiple pay zones. Before the spacing decision it had identified two other drilling locations and installed a pipeline to market the gas.

IEA: Global crude to get heavier, sweeter

The global crude slate will become heavier and slightly sweeter during 2006-11, predicts the International Energy Agency, Paris.

Global average crude will move to 32.5° gravity from 32.7° during the period, IEA says in its September Oil Market Report. A lightening of crude from the Middle East and Russia will be offset by heavier production elsewhere. Global average sulfur content of crude supply will decline to 1.16% from 1.18%.

IEA's analysis covered crude oil and condensate and excluded NGLs, biofuels, transport fuel blending components, and refinery processing gains. It used production capacities of members of the Organization of Petroleum Exporting Countries rather than actual production.

In the Middle East, which accounts for 36% of an expected 9.6 million b/d supply increase through 2011, crude lightens to 34.1° from 34.0° gravity while dropping to 1.73% sulfur from 1.78%.

The quality changes come mainly from new condensate streams, especially in Qatar and Iran, and Saudi Arabia's attempt to boost supply of Arab Light crude at the expense of heavier and sourer grades, IEA says.

The most improvement in projected quality in IEA's analysis occurs in the former Soviet Union, where average crude will rise to 34.3° from 33.7° gravity while sulfur content drops to 1.15% from 1.28%.

While Russian Urals crude moderates the effect, the improvement will come from Azeri crude and Shah Deniz liquids off Azerbaijan, production from Russia's Sakhalin projects, and supply from Kazakhstan's Karachaganak and Kashagan fields.

Oil supply will sweeten slightly to 0.35% sulfur in Africa and to 1.07% in Latin America by 2011, IEA says. But production becomes heavier by 0.7-0.8° gravity in each region to 35.4° gravity in Africa and 25.5° gravity in Latin America. Driving the quality changes are increased deepwater production off Angola and Brazil.

Like its production, the Asia-Pacific region's crude quality will change little, averaging 34° gravity and 0.18% sulfur.

North American supply will degrade to 27.7° gravity in 2011 from 27.0° in 2006 and to 1.60% sulfur from 1.54%. Growing production from Canadian oil sands is the main reason.

Supply from the North Sea will move to 35.8° gravity from 35.4° in IEA's study period. Sulfur content will rise to 0.38% in 2008 but return in 2011 to its 2006 level of 0.37%. ✦

Processing — *Quick Takes*

BP to invest $3 billion in Whiting refinery upgrade

BP PLC is in the final planning stage of a $3 billion investment to increase capacity to process Canadian heavy crude oil at its 399,000 b/cd Whiting refinery in northwest Indiana.

The company said reconfiguring the refinery has the potential to increase production of motor fuels by about 15% from its current capacity of 4.5 billion gal/year.

The project includes construction of a world-scale coking unit, a hydrogen production plant, and sulfur recovery facilities. BP said the replacement processing units and enhancements to existing refinery units will increase Canadian heavy crude oil processing capability by about 260,000 b/d.

Project construction is slated to begin in 2007 and be completed by 2011, pending regulatory approvals.

Contract awarded for Tatarstan refinery

CJSC Nizhnekamsk Refinery has let a contract to Foster Wheeler Ltd.'s Paris-based subsidiary Foster Wheeler France SA for front-end engineering and design for a refining and petrochemical complex to be built in Nizhnekamsk in Tatarstan, Russia.

The contract, terms for which were not disclosed, is an addition to an existing project management consultancy contract awarded in 2005.

The planned complex, expected to cost more than $3 billion, will consist of a refinery with 140,000 b/d distillation capacity, a deep conversion refinery, and a petrochemical plant. Construction of the complex will occur in three separate phases during 2008-10.

The oil processing section of the complex will include aromatic units and a deep conversion section with a fluidized catalytic cracker, a distillate hydrocracker, a delayed coker, and a gasification plant. The petrochemical section of the complex will include purified terephthalic acid, polyethylene terephthalate, linear alkylbenzene and polypropylene units, plus the associated power generation facilities.

Neste gets animal fat for biodiesel production

Neste Oil Corp. has signed long-term procurement contracts with Honkajoki Oy and Findest Protein Oy, both owned by Finnish food manufacturers, for the supply of animal fat for biodiesel production at Neste's 200,000 b/cd Porvoo, Finland, refinery.

Neste plans to import additional animal fat to supplement insufficient Finnish supplies, said Kimmo Rahkamo, Neste Oil's executive vice-president, components.

Current diesel fuel production capacity at Porvoo is 4 million tonnes/year, but Neste Oil is constructing a 170,000-tonne/year biodiesel plant on the site as the European Union has challenged member nations to increase renewable biofuel usage to 5.75% of all gasoline and diesel fuels by 2010.

Production at the plant will be based on Neste Oil's proprietary technology that can use a flexible input of any vegetable oil or animal fat.

Biofuel production is expected to begin in summer 2007 at the new €100 million plant. ✦

Transportation — *Quick Takes*

Woodside undertakes LNG study off Australia

Woodside Energy Ltd. hired Foster Wheeler Energy Ltd. to study a proposed offshore LNG development that would process gas from Browse basin off Western Australia.

The contract value was not disclosed. Foster Wheeler, together with WorleyParsons Services Pty. Ltd., will evaluate technical considerations for the Browse LNG project, which comprises the East and West Browse joint ventures operated by Woodside.

Fields involved would be Torosa, Brecknock, and Calliance in 35-700 m of water.

Sonatrach awards ABB pump station contract

Algeria's state-owned Sonatrach has awarded ABB Group, Zurich, a $215 million contract to construct two pumping stations and automation systems on the 665-km NK-1 oil pipeline linking oil fields in Algeria at Haoud El Hamra with the Mediterranean port of Skikda.

ABB will provide engineering, procurement, construction, and commissioning of the new pumping stations, terminal upgrades, and a 44-km fuel pipeline.

The NK-1 project, scheduled for completion in late 2008, will add 18 million tonnes/year to Algeria's oil transport capacity. ✦

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Letters

Rate of conversion

The ongoing discussions about "peak oil" have continually skirted the one unifying concept which addresses the reality about the (eventual) peaking of global liquids production. The realities can perhaps best be summarized by addressing the rate of conversion of resources to production capacity or supply.

Our industry is perhaps flat out in terms of its abilities to add additional low-cost supply. We may be at the peak *rate of conversion* reflected in increasing costs from the service providers and the squeezing of profitability for producers. In some areas, this increase in costs (and reduction in product prices) is reflected in margins of profitability being reduced to levels experienced in the 1990s. Indeed, this is also occurring when the intensity of effort (aided by marvelous digital capabilities) by an aging but limited skilled workforce for small but profitable reserves has never been greater.

We have seen a number of recent comments by executives associated with larger oil and gas enterprises who allude to the vast global endowment of hydrocarbons ("adequate resources") sufficient to meet projected global demand for liquid fuels but in the fine print have caveats such as "provided there are timely access, investment, and technological gains." Of course, there is the added implication that such caveats will provide for a sustainable profitable industry.

Arguments about adequate resources provide little comfort to those charged with finding, developing, and producing the enormous amounts of hydrocarbon liquids to feed the apparently ever-growing global appetite. Indeed, to suggest there are adequate physical hydrocarbon resources is a "no-lose" use of terminology.

A better appreciation of the difficulties now apparent is to consider the issue as one to do with the rate of conversion of hydrocarbon resources to capacity. The rate or pace of conversion to required products has many chokepoints or bottlenecks. Some are, for example, an adequate skilled workforce, availability of suitable drilling rigs, tanker capacity, refining capacity, resource habitat, field

size distributions, basin location, access to the resources (actual or speculated), environmental constraints including emissions, water, the price "margin," profitability, available investment, fiscal terms, technological limitations, suitable markets, truck tires, return on energy investment, etc. The importance of any principle choke point, for example, may vary between geographic regions, the type of products, and markets, but, no matter what the choke point, the rate of conversion is impeded.

Vast resources of oil sands and oil in shales do not answer the issue (OGJ, Apr. 24, 2006, p. 32). For example, if we accept 175 billion bbl of oil as resources in the Alberta oil sands, even at a production rate of 3 million b/d or 1 billion bbl/year, the annualized "rate of conversion" is less than 1%. This is less than the current global production loss per annum via field and basin depletion.

We should all be aware that the rate of conversion might be reaching a peak irrespective of demand, price, netback, crude quality, and the speculated global endowment of resources. This "peak" has already occurred in many oil and gas productive basins, which have had an historical transparency in terms of access, ready markets, favorable fiscal terms, security, and perceived political risk.

Keith Skipper
NorthStar Energy Pty. Ltd.
Sydney, Australia

Calendar

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

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Journally Speaking

Steam-cleaning heavy crude

Guntis Moritis
Production Editor

Steam injection is effective for increasing recovery from subsurface heavy crude or bitumen accumulations. Some projects do produce these resources with cold production, but recovery expectations are low, in the range of 5-10% of initial oil in place. With steam injection, recoveries in some projects may exceed 70%.

As discussed in the lead article in the Production Report, p. 39, the next decade will have a host of new steam projects starting in Alberta that will contribute greatly to the province's plans for exploiting its estimated 174 billion bbl of heavy-oil resource out of the 1.69 trillion bbl in place.

But Alberta is not alone in having large heavy crude accumulations. These resources are found in many regions of the world, including Venezuela, China, Indonesia, India, the Middle East, Brazil, Albania, Russia, the North Slope of Alaska, California, and Texas.

Heavy crudes

The definition of heavy and extra-heavy crude oil and bitumen varies but usually says that it is a petroleum or petroleum-like liquid or semisolid occurring naturally in porous and fractured formations. Other names for bitumen deposits include tar sand, oil sand, oil-impregnated rock, and bituminous sand.

Viscosity and density usually characterize the substance.

Viscosity differentiates between crude and bitumen, while density differentiates extra-heavy, heavy, and other crudes.

Bitumens have viscosities greater than 10,000 cp. Crude oils have viscosities less than or equal to 10,000 cp. These are gas-free viscosities, measured at the original reservoir temperature.

Extra-heavy crude has API gravities less than 10°, while heavy crude gravity varies from 10° to 20° at 60° F. and atmospheric pressure.

Steam injection

Steam-assisted gravity drainage (SAGD), which uses parallel horizontal wells such as are planned for many projects in Alberta, is relatively new. Other projects in Alberta, such as at Imperial Oil Ltd.'s project at Cold Lake, produce with a cyclic steam process, in which the same well is both the injector and producer. Production from Cold Lake is increasing and currently is about 140,000 bo/d.

The use of steam for recovering heavy crude started in the 1960s in Venezuela and California. Cyclic steam injection was the initial process used, although many projects, especially in California, were converted to steamfloods with dedicated injection and producing wells. California still produces about 280,000 bo/d from steam projects, although this is down from the peak in the mid-1980s of about 480,000 bo/d. Steam has enabled the recovery of several billion barrels of crude from the San Joaquin basin in California.

Chevron Corp., one of the major steamflood operators in California, sees production from its properties continuing to decline—although at 2%/year compared with the 4%/year declines experienced in recent years.

A unit of Chevron also operates the largest steamflood in the world in the Duri field in Indonesia. Current production is about 200,000 bo/d, compared with a peak of about 300,000 bo/d in the mid-1990s. Prior to the 1985 start of steamflooding in Duri, the field produced about 30,000 bo/d.

Although production in Duri continues to decline, Chevron is initiating a steamflood in North Duri. It expects production in North Duri to peak at 35,000 bo/d after the start-up in 2008.

Chevron also is expanding its pilot steamflood in the Partitioned Neutral Zone between Kuwait and Saudi Arabia.

Another new steamflood in the Middle East is in the Mukhaiza field, Oman. Occidental Petroleum Corp. plans for steam injection to start in 2006. The $3 billion project may include more than 1,800 wells and has a target production of 150,000 bo/d in 2011.

Bankers Petroleum Ltd., Calgary, is redeveloping the giant Patos-Marinza heavy oil field in central Albania and has started studying the potential for injecting steam for increasing the recovery factor of the 2 billion bbl originally in place above the 10% expected under cold production.

Patos-Marinza was discovered in 1928 and placed on production in 1939.

The Exploration Co. in August started injecting steam in two wells in the Maverick basin of South Texas. Its San Miguel heavy oil field project targets the recovery of some of the 7-10 billion bbl of heavy oil estimated to reside in the basin.

Although steam generation adds costs, it is essential for cleaning out a greater amount of the heavy crudes found in many of the world's sedimentary basins. ✦

Russian energy security

While voicing concern for energy security, Russia last week forfeited its credibility on the subject. At an international meeting in Sochi, Russia, Sept. 17, President Vladimir Putin described his country's plans to boost energy exports to the Asia-Pacific region. He validly asserted that security of markets is as important to producing nations as security of supply is to consumers. Yet he had nothing to say about security of investments crucial to supply.

Indeed, the day after the Sochi remarks, Putin's government announced a move that might shut Royal Dutch Shell PLC and its partners out of a $20 billion production, pipeline, and LNG project under construction on Sakhalin Island in the Russian Far East. The stunner evoked protests from, among numerous other parties, Japanese importers relying on LNG from the jeopardized second phase of the Sakhalin-2 project.

With energy security, perspective is everything.

Jab to Europe

Putin's commentary about security of markets jabbed Europe as much as it provided context for Russia's export plans. The Asia-Pacific claim on Russian energy exports, Putin said, will rise to 30% in 10 years from 3% now, largely because of new gas pipelines to China. Russian gas piped eastward is gas not available to Europe, where importers won't find much comfort in the Russian president's mention of the planned North European Gas Pipeline as part of his market diversification strategy.

Europeans have been in an understandable uproar over security of Russian gas supply since January, when state-owned Gazprom curtailed pipeline deliveries to Ukraine during a price dispute with noisy political undertones, disrupting gas movement to Europe. At a May Russian-European Union summit in Sochi, EU officials advocated the European Energy Charter, an agreement Russia hasn't ratified that would broaden access to Russian energy supplies and transportation. In response, Putin demanded concessions from the EU. His hard line aggravated concern that Russia is reverting to Soviet-style use of energy to influence international politics. But the Russian president had reason to be testy: EU members were already scrambling to find gas sources other than Russia.

Whatever the provocation, Moscow's determination to squeeze foreign energy buyers and investors is clear and disturbing. For nearly 3 years, an open question has been whether the jailing of Yukos founder Mikhail Khodorkovsky and expropriation of the company's assets represented one-time brutalities reserved for politically adventurous Russians. Apparently, foreign companies have reason to worry.

A government injunction that rescinds permits for Sakhalin-2's second phase alleges threats to marine life resulting from inadequacy of environmental safeguards. Shell and its partners in Sakhalin Energy Investment Co., Mitsubishi and Mitsui, dispute the claims. But revocation of the permits effectively suspends the project, the second phase of which was to begin LNG deliveries next year. Oil production under the first phase started in 1999.

There has been speculation that Russia is pressuring the Sakhalin-2 partnership to improve terms of the planned acquisition of a 25% interest by Gazprom. The Russian company agreed to the deal before Sakhalin Energy doubled cost estimates for the project last year. If that's the motive, the tactic is barbaric. It's no less so if there really is an environmental problem. Summary project suspension is no way to enforce regulation; in fact, it makes the allegations suspicious.

Energy crackdown

Moscow's energy crackdown is advancing on other fronts. The Financial Times on Sept. 20 reported threats by Russian prosecutors to suspend the license of TNK-BP to develop Kovytka gas field in eastern Siberia. In that case, as with Sakhalin-2, the allegations are environmental in nature, and Gazprom also is flirting for a stake in the venture. And Interfax reported that an official of the Natural Resources Ministry has hinted that the other two Sakhalin Island projects are in violation of their licenses.

From any perspective, energy security suffers when government pressures in important producing nations weaken the foundations for international investment. Security comes more from the interdependence central to business activity than from controls and decrees. But business depends on trust and rule of law. Moscow's apparent preference for domination undermines anything it says about energy security. ✦

US gas market responds to hurricane disruptions

David Wood
David Wood & Associates, Lincoln, UK

Saeid Mokhatab
University of Wyoming Laramie, Wyo.

Since 2002, storm-related natural gas production shutins in the Gulf of Mexico have had a much greater impact on the US gas market than in previous years. Facilities insurers seem to think this a trend that is here to stay.

The combined effects of the 2004 and 2005 hurricane seasons had an impact across all sectors of the US gas industry. Hurricane Ivan, which made landfall in September 2004, caused more long-term gas production interruptions than any previous hurricane, but its impacts were dwarfed by Hurricanes Katrina (landfall Aug. 29, 2005) and Rita (Sept. 24, 2005). The combined effects of Hurricanes Katrina and Rita were by far the most damaging in the history of the US petroleum industry (Fig. 1).

The hurricanes also substantially damaged gas processing and pipeline facilities needed to process and deliver gas to customers. It will take the industry several years to recover from the disruptions, and some lost production will never be recovered.

The Gulf of Mexico accounts for 40% of US gas production. This concentration of gas production, processing, and transportation facilities in the gulf and on the Gulf Coast means that a significant percentage of domestic oil and gas production and processing is vulnerable to disruption by hurricanes.

The volume of gas production curtailed during the third week of October 2005 from both onshore and offshore areas of the Gulf Coast was 5 bcfd—about one half of prehurricane offshore production. The US Minerals Management Service (MMS) in June of this year reported that the cumulative shut-in gas production from Aug. 26, 2005, to June 19, 2006, was 803.6 bcf. That is about 22% of the total annual gas production in the gulf (3.65 tcf). To place this in perspective, 630 bcf of gas was imported into the US as LNG in 2005.

Status of recovery

Recovery efforts in the Gulf of Mexico in fourth quarter 2005 were impressive, returning to service some three quarters of the supplies shut in by offshore and onshore storm damage in Louisiana. The Federal Energy Regulatory Commission (FERC) reported in February of this year that 2.4 bcfd of production remained shut in by January—1.8 bcfd offshore and 0.6 bcfd onshore in Louisiana.

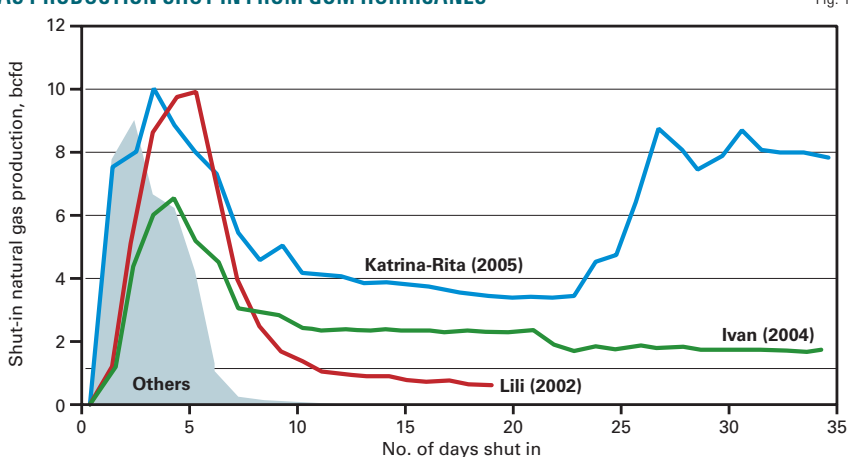
The pace of recovery alleviated immediate gas supply concerns for the winter of 2005-06. In the first half of 2006 there was a progressive and substantial improvement in both oil and gas production from the gulf. In Fig. 2 the volume of shut-in offshore and onshore Gulf of Mexico gas production illustrates the scale of the 2005 hurricanes' impact and the pace of recovery.

Energy and Environmental Analysis Inc., Arlington, Va., forecast that cumulative gas shutins to August 2006 for Katrina and Rita would be 900-1,100 bcf. This volume, which has proved to be an accurate prediction, was more than five times the shut-in volume from Hurricane Ivan.

MMS in June reported shut-in gas production of 935.67 MMcfd. This is equivalent to 9.4% of the daily gas production in the gulf, which currently is 10 bcfd.

Of the 68 platforms still evacuated

GAS PRODUCTION SHUT IN FROM GOM HURRICANES* Fig. 1



*In the Gulf of Mexico during 1995-2005.
Sources: Energy & Environmental Analysis Inc. report, November 2005, David Wood & Associates

in June this year, 66 are in the Lake Charles, Lafayette, and New Orleans areas, where more than 80% of the shut-in gas is located. It now appears that at least some of this remaining shut-in production may never be fully recovered. These evacuations are equivalent to 8.3% of 819 manned platforms.

The position for gas was substantially better than for oil. MMS in June reported shut-in oil production of 179,970 b/d of oil, equivalent to some 12% of the daily oil production in the gulf, i.e., about 1.5 million b/d.

Spot gas prices impact

After Hurricane Ivan, Henry Hub gas prices increased to a peak of $8/MMbtu from $6/MMbtu in July 2004. By February 2005, gas prices had returned to slightly more than $6/MMbtu but shot up again during the summer to about $10/MMbtu as world oil prices rose and gas supply concerns increased. Gas prices then increased significantly in third quarter 2005, trading as high as $16/MMbtu on spot markets after Hurricanes Rita and Katrina (Fig. 3). The spot gas price trend at Henry Hub from July 2005 to July 2006 illustrates the impact of the 2005 hurricanes and, apart from early December 2005, the mild winter that followed.

Since then, prices have fluctuated predictably with changing weather: lower during a warm November 2005, higher during very cold weather in early December 2005—peaking above $15/MMbtu—and again moving lower during the milder 2006 winter and spring. Prices dropped progressively to less than $5.50/MMbtu in early July of this year from above $8/MMbtu in late January, but prices reversed in July, rising above $8/MMbtu on July 31 to the highest level in almost 6 months. The price hike was a response to hot summer weather and anticipated record seasonal demand for electricity.

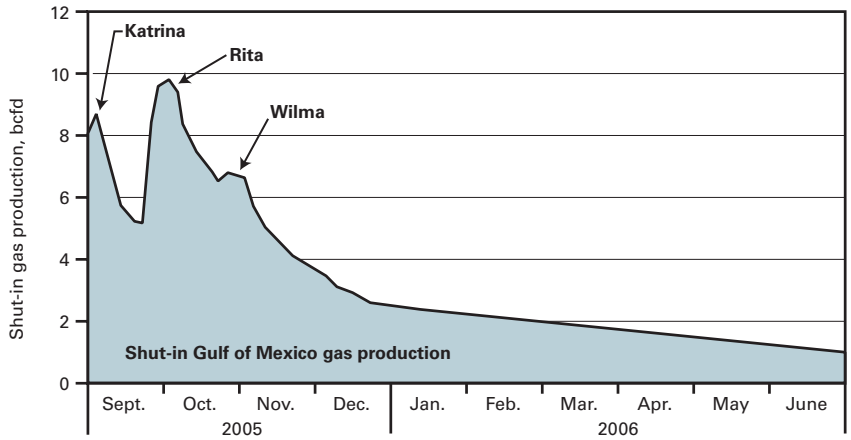
These prices, although much lower than the peak prices in third and fourth quarters 2005, are still high by historical US standards. Before the hurricanes, gas prices had reached levels that reflected an ongoing tightness between supply and demand. Despite the mild 2005-06 winter, gas markets appear to expect gas prices to remain high in historical terms for some years. These prices likely will persist until domestic gas production increases or, more likely, until additional LNG import capacity materializes.

Declining domestic production, coupled with increasing demand and limited import capacity, caused the tight gas supply-demand balance that has prevailed in recent years. This undoubtedly magnified the impact of large-scale hurricane disruptions on energy supply and prices and is also influencing ongoing responses.

Spot Henry Hub gas prices averaged $8.86/Mcf in 2005, and the US Energy Information Administration (EIA) in July of this year expected prices to average less than $7/Mcf for the third quarter. Barring extreme weather for the remainder of 2006, EIA in July expected a decline in the 2006 annual average Henry Hub spot price to about $7.61/Mcf. However, the agency expected these relatively low prices to be short-lived, as concerns about potential future supply tightness and continuing

IMPACT OF 2005 HURRICANES ON GOM GAS PRODUCTION

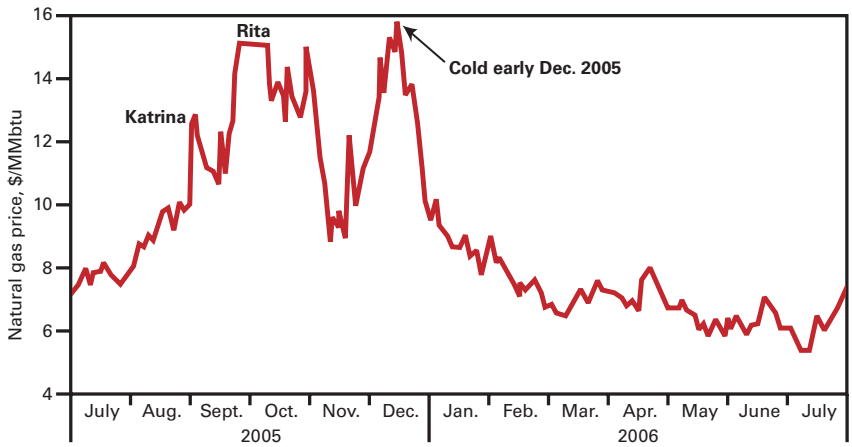
Fig. 2



Source: June 2005 US Minerals Management Service data, David Wood & Associates

2005 HURRICANE IMPACT ON HENRY HUB SPOT GAS PRICE

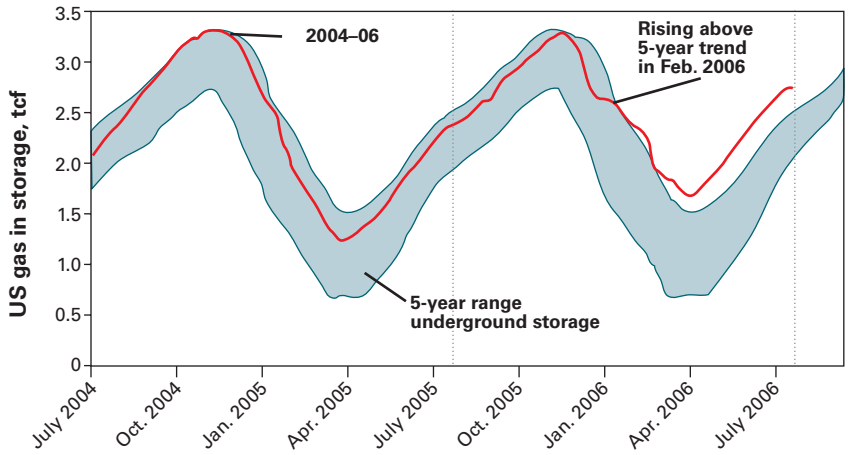
Fig. 3



Source: David Wood & Associates

US NATURAL GAS STORAGE INVENTORIES

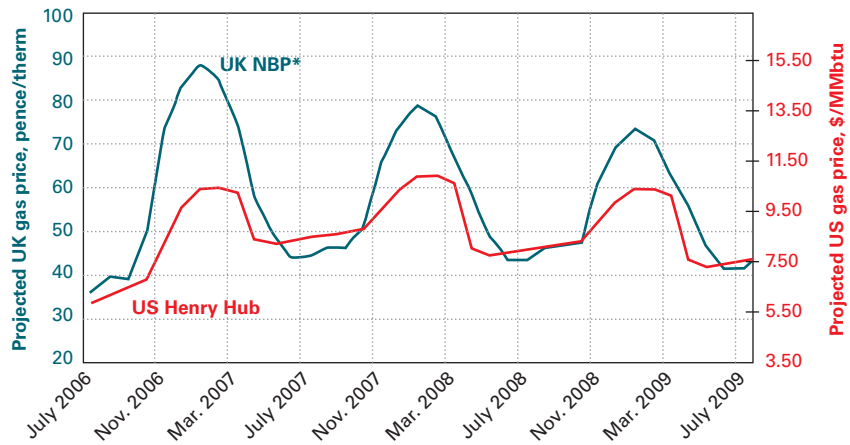
Fig. 4



Source: Energy Information Administration Weekly Natural Gas Storage Report, July 21, 2006

US, UK PROJECTED PRICE CURVE COMPARISONS

Fig. 5



*Regional market hubs in the UK are organized around a notional delivery point, the National Balancing Point (NBP).
Source: Total Gas & Power, Monthly Brief, June 2006

pressure from high oil market prices could drive spot gas prices to just over $9/Mcf in winter 2006-07 (Fig. 5). EIA forecasts that Henry Hub prices will average $8.13/Mcf in 2007.

Storage inventory trends

The US gas industry entered winter 2005-06 with high levels of gas storage despite the supply interruptions from the hurricanes. This was a strategic and prudent response to provide insurance against the possibility of a cold winter, which fortunately did not materialize. EIA documents the volume of working gas in storage in the Lower 48 states as 2,756 bcf as of July 21. Gas stocks were 379 bcf higher than for the same week in 2005 and 490 bcf above the 5-year average of 2,266 bcf. Stocks in the producing region were 154 bcf above its 5-year average of 696 bcf.

Total working gas in storage, which has remained above the 5-year historical range since February of this year, is serving as a security cushion against potential disruptions from the 2006 hurricane season (Fig. 4). The relatively warm winter of early 2006, mild spring and early summer temperatures, and the wide difference by which prices for future delivery contracts for the 2006-07 winter months exceeded spot prices have contributed to this high midyear gas storage level.

Indeed, LNG imports in the first quarter of this year were down substantially from 2005 and 2004 levels, partly due to high gas stocks, but LNG imports rebounded strongly in the second quarter to further boost gas stocks.

Regulatory responses

In addition to increased gas in storage, the impact of the hurricanes triggered action by regulatory authorities, who accelerated progress in gas infrastructure and market developments that had been impeded by slow regulatory responses in recent years. These include:

- Approving applications for a substantial number of new LNG receiving terminals to facilitate expansion of imported gas.
- Approving applications for new pipelines and changes to pipeline tariffs to help pipelines force compliance with operational flow orders. This will enable pipeline companies to maintain system reliability and avoid bottlenecks during periods of unexpected gas supply interruption.
- FERC this year strengthened its enforcement policy and its ability to detect gas market manipulation, which has been an historic problem for the gas markets during periods of high prices. It also now has powers to impose higher penalties for market manipulation violations.

Since deregulation of the US gas market in 1989, FERC does not directly regulate most wholesale gas prices and has no jurisdiction over retail gas prices, but it does issue infrastructure approvals and has the power to act against illegal manipulation of the gas markets.

Future price implications

Gas prices on the futures exchanges—the forward price curve—provide an indication of market expectation for prices in the near term. Forward

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

TenarisBlue® Dopeless™ connections open up a zero-discharge world for Statoil.

Statoil called upon Tenaris to supply TenarisBlue® Dopeless™ premium connections when it came to develop its Snøhvit field in the environmentally sensitive Barents Sea. The dry, dope-free connections are being used for all casing and tubing in a full range of materials – including carbon, chrome and CRA – because the Dopeless™ technology eliminates discharges, allows fast and clean make-up and makes for safer working conditions on the rig. Our innovations are opening up a new world of possibilities and making life easier for our customers, their crews and the environment.

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REGIONAL VARIATIONS IN LNG PRICES, $/MMbtu

Fig. 6

US	Cove Pt.	US Avg.
July 05	5.66	6.40
Jan. 06	10.43	10.04
Feb. 06	8.77	8.77
Apr. 06	7.49	7.49

Europe	France	Belgium	Spain
July 05	4.71	7.74	4.97
Jan. 06	5.78	10.10	5.68
Feb. 06	6.12	12.18	5.83
Apr. 06	6.42	10.76	5.02

Asia	Japan	S. Korea	Taiwan
July 05	5.97	6.84	7.71
Jan. 06	6.56	7.21	8.41
Feb. 06	6.39	7.82	8.46
Apr. 06	6.45	7.64	8.83

Source: Argus Global LNG Monthly, 2006

price curves indicate supply-demand constraints in both US and UK gas markets to 2009 (Fig. 5). These are not price predictions but what the market is willing to trade at now for future supply. In practice, gas spot prices are strongly influenced by weather, with hot summers and cold winters tending to increase spot gas prices, while mild weather lowers them.

High gas inventories have a moderating effect on price rises; low inventories have the opposite effect. The forward curve is similarly impacted by gas inventories (and vice versa) and by supply-demand fundamentals and perception. Lack of import capacity and potential disruption to domestic and international supplies do lead to increased forward price curves, and this is what the US gas markets continue to experience.

Forward prices for winter 2005-06 were some 25% higher than the July 2006 prices (front month of the forward curve) quoted in June 2006 (Fig. 5). Through to 2009 the forward price curve of early July 2006 anticipated recurring peak winter prices of $10-11/MMbtu for the next three winters, with gas prices remaining above $7.50/MMbtu each year through to July 2009.

Such prices remain highly attractive for the development of international LNG projects—with break-even prices at $2.50-3.50/MMbtu—to supply the US gas market in the medium term through new LNG receiving infrastructure.

Gas prices in the longer-term will depend on several factors, such as world oil prices and the pace of development of additional gas supply through LNG imports.

The effect of near-term domestic gas supply constraints and potentially high prices are apt to be felt primarily in the eastern US, which is most dependent on gas from the Gulf Coast region. The western US, which receives gas from the Rockies, West Texas on-shore producers, and Canada, should be affected less.

The limited current capacity to move gas from west to east may create a marked differentiation between gas prices in the eastern and western US. Such impacts are potentially most significant for large industrial and power generation gas consumers, who have tended in recent years to rely more on spot market gas purchases.

Future gas imports role

In 2005, the US produced 84% of the gas it consumed, but few believe that this is sustainable because of dwindling domestic gas reserves. The US imports the remainder from Canada and from overseas as LNG. Canada is part of the same market trading area and is also experiencing tight supply-demand balances in the near term. The US competes with the two other major gas-consuming regions, Europe and Asia, for its LNG imports. Most gas is traded into those regions under long-term sale and purchase contracts.

EIA, in its "Short-term Energy Outlook, July 2006," projects that total US gas consumption this year will fall below 2005 levels by 1.7% then increase by 4.2% in 2007. An exceptionally warm January 2006 has residential gas consumption projected to fall in 2006 by 7.4% from 2005 levels and then increase by 8.8% in 2007. Following recovery from the 2005 hurricane season, the output of gas-intensive industries likely will contribute to a 1.4% growth in industrial gas consumption this year and 4.7% in 2007.

In 2005, US dry gas production declined by 2.7%, largely because hurricanes damaged infrastructure in the Gulf of Mexico. EIA projects dry gas production to increase by 0.6% in 2006 and 1.1% in 2007, which will not keep pace with demand growth. EIA also forecasts total LNG net imports to increase from their 2005 level of 630 bcf to 760 bcf in 2006 and to 1,000 bcf in 2007.

Even where markets have been deregulated and spot markets are active, e.g., the UK, prices have from time to time been higher than those experienced in North America in the last 2 years (Fig. 6). The 2005-06 winter in Europe was very cold. In addition, tight supply caused by interruptions of pipeline gas from Russia in January during a dispute with transit country Ukraine resulted in high gas prices in continental Europe and some supply disruption.

An even tighter near-term supply shortfall in the UK has resulted in high spot and forward gas price curves as demand outstrips import infrastructure capacity, and disruptions of gas storage capacity have exacerbated the problem in 2006. The highly seasonal UK gas forward curve anticipates a continued

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problem in winters through to 2008-09 (Fig. 5).

Depending on contract price indexation either to the price of oil—common in Europe and Asia—or a gas hub benchmark price such as Henry Hub in the US or the UK's National Balancing Point, the price of delivered LNG can vary substantially between regional markets. As a result, where short-term contracts permit, gas sellers have diverted LNG deliveries to northwest Europe to take advantage of the high prices, and deliveries of LNG to the US were lower as a consequence in fourth quarter 2005 and first quarter 2006 (Fig. 6). Of course, diversions in the other direction also occur when the prices in the US exceed those in Europe.

In the future, as more gas-producing countries build LNG liquefaction-export plants, diversifying and increasing overall supply, international competition for that gas is expected to be strong, particularly in the Atlantic Basin. As a result, new LNG import terminal and regasification infrastructure is set to play a key role in the future US gas supply, and both long-term and short-term LNG contracts will probably be required to secure LNG volumes in periods of peak demand. ✦

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The authors

David Wood (woodda@compuserve.com) is principal of David Wood & Associates, an international consultant specializing in the integration of technical, economic, risk, and strategic information. He holds a PhD from Imperial College, London. His services include project evaluation, research, and training on a wide range of technical and commercial topics. Based in Lincoln, UK, Wood operates worldwide.

Saeid Mokhatab (smokhatab@gmail.com) is a natural gas engineering research advisor for the University of Wyoming's Chemical and Petroleum Engineering Department and is an international associate of David Wood & Associates. He has participated as a senior consultant in international projects and has written extensively on gas transportation, LNG, processing, gas economics, and geopolitical issues. Mokhatab holds a BS in gas engineering from the University of Tehran and an MS (2000) in chemical engineering from Tarbiat Modarres University, Tehran. He is a member of the Society of Petroleum Engineers and several other professional organizations.

NGSA, INGAA concur on blanket certificate proposals

Nick Snow
Washington Correspondent

US natural gas producers and pipelines have worked out the minor differences between their proposals to improve blanket certificate procedures, the Natural Gas Supply Association and the Interstate Natural Gas Association of America jointly announced Sept. 19.

"In sum, our organizations, which are sometimes at odds on major issues before the [Federal Energy Regulatory] Commission, remain steadfast in our mutual support for reforms that facilitate natural gas infrastructure development," NGSA Pres. R. Skip Horvath and INGAA Pres. Donald F. Santa Jr. said in a joint letter to FERC Chairman Joseph T. Kelliher.

The two trade associations jointly petitioned FERC in November 2005 to initiate a rulemaking to improve blanket certificate procedures by extending the authority to interstate systems that previously were not eligible.

Companies that hold blanket certificates can improve or upgrade existing facilities meeting certain criteria without obtaining a case-specific authorization under Section 7 of the Natural Gas Act.

FERC responded with a notice of proposed rulemaking (NOPR) in June. NGSA and INGAA separately advised the commission on Aug. 25 that "practical considerations required separate filings," Santa and Horvath said.

"We urged you, however, not to construe this as a sign of departure from the pipeline-producer joint consensus outlined in our original joint petition for rulemaking," they said.

Agreement reached

The two associations have since had time to review each other's comments, which agreed on major issues such as urging FERC to liberalize restrictions on blanket processing.

NGSA and INGAA also examined differences in their comments "that are more in the nature of degree or importance rather than principle" and reached agreements on four main points:

- More than one billion people on earth do not have a safe supply of water.

- The water needed to produce one automobile is seven times more than one person drinks in their lifetime.

- The water needed to refine one day of our world's oil consumption is 3,000 times the volume of the English Channel.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

The Sakhalin bear dance

Dancing with the Russian bear has been the rage lately, especially in the oil industry. It reminds me of the old song "Simon Smith and His Dancing Bear."

As the lyrics go, "Oh, I'd step out in style with my sincere smile and my dancing bear." And they go on to say, "Oh, who would think a boy and bear could be well accepted everywhere. Its just amazing how fair people can be."

Words to that effect may well have been believed by many folks in the oil and gas industry, judging by the number of bears in the Kremlin picking up partners right and left. Many of their sincere smiles, though, have turned to unhappy frowns as the erstwhile partners now see the lyrics in an altogether different light.

New light

That light shone last week when Russian Natural Resources Minister Yuriy Trutnev signed a document revoking the order of 2003 endorsing a positive environmental analysis of the Sakhalin-2 project. And pace any legal niceties, that order came into force the moment it was signed.

It all came about on Sept. 18, when Trutnev considered an objection by Deputy Prosecutor-Gen. Aleksandr Buksman to the ministry's order of July 15, 2003, called "On endorsing the conclusions of the commission of experts drawn from the state environmental analysis of the feasibility study for the integrated development of the Piltun-Astokhskiy and Lunskiy licensed fields (stage 2 of the Sakhalin-2 project)."

Not much was said about Buksman's objections, nor are we to expect much ever will be said—certainly not in the courts. At best, we are left to understand that the Russians either are using the revocation as a bargaining ploy to get a slice of the project, or they want to dance off with the whole thing.

Soft shoe

Royal Dutch Shell PLC, which has a 55% stake in the project, has been in talks with state-owned OAO Gazprom for more than a year about trading 25% of its share in Sakhalin-2. Gazprom has been offering a 50% stake in one of its onshore fields in central Siberia, but Shell has not been overly keen.

Last week, ahead of Trutman's revocation, Gazprom suddenly said the talks with Shell over the possible asset swap were off. There was no explanation at all, just a closed door. Gazprom said there had been "no movement in the past year," and that was that. The dance was over.

Or was it? The main question being asked in industry circles was whether the Kremlin's tough line spelled seriously bad news for Shell or whether it was simply a negotiating ploy to extract better terms from the deal for Russia.

Either way, it seems that the boy and his dancing bear just cannot be accepted everywhere. And that leads us to question that wonderful line, "It's just amazing how fair people can be." ✦

- *Higher blanket dollar limits.* INGAA, in its comments, urged FERC to adopt temporary cost limits previously established in response to Hurricanes Katrina and Rita: $16 million for automatic projects and $50 million for prior notice projects. NGSA now agrees that the limits should govern access to blanket procedures, subject to the index proposed in the NOPR.
- *Notification provisions.* NGSA objected to FERC's proposal to extend a protest deadline to 60 days from 45 days. INGAA did not object to the 60-day protest limit, subject to the increased cost limits it proposed, but did object to the proposal to increase landowner notice of construction to 45 days from 30 days for automatic authorization projects. The associations now consider both notification proposals ill-advised and urged FERC to reconsider the need for increased notification.
- *Automatic processing.* Both associations supported FERC's proposals to open mainline and some LNG-related projects to prior notice blanket proceedings. But they also urged the commission to go further and allow blanket certification of new takeaway lateral facilities to connect existing LNG terminals with existing pipelines. INGAA also urged FERC to remove a proposed restriction on allowing automatic processing of mainline and LNG-related facilities that meet whatever cost criteria are adopted. NGSA now agrees with INGAA that these proposed restrictions aren't necessary.
- *Environmental conditions.* INGAA said that some of FERC's proposed new environmental regulations were ill-advised for several reasons, a position that NGSA now supports.

Horvath and Santa's letter to Kelliher came nearly 2 weeks after the American Public Gas Association questioned the necessity of revising blanket certificate regulations for gas infrastructure projects.

APGA, which represents municipal and other publicly owned local distribution companies, said in comments filed Sept. 6 that the Natural Gas Act's

Section 7 procedures are in place to protect the public interest.

It also said where a project may be built by prior notice only, "it is very important that the FERC staff use the prior notice period to review the applications in order to bring to bear their expertise on projects that will otherwise go unexamined." ✦

Burton: Confusion led to price threshold omission

Nick Snow
Washington Correspondent

Confusion over where to place a price threshold in the final rule may have led to its omission in federal deepwater leases in 1998 and 1999, US Minerals Management Service Director Johnnie Burton told a US House committee Sept. 14.

Burton emphasized that the Department of the Interior agency still is not certain what actually happened. She awaits the results of an investigation she requested from Earl E. Devaney, the department's inspector general, soon after learning of the omission in early 2006.

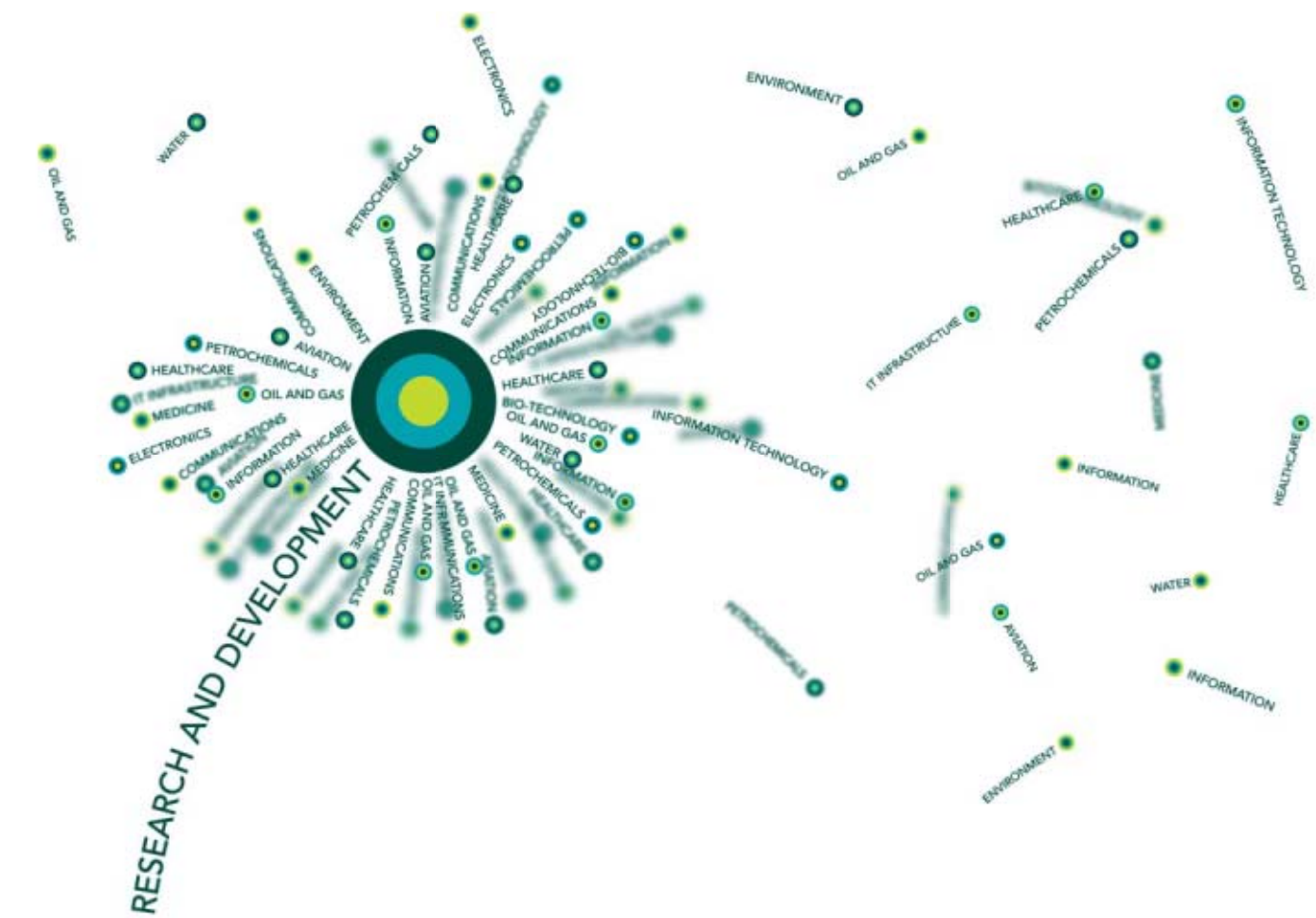
But Burton told the House Government Operations Committee that MMS's own inquiries show that after Congress passed the Deepwater Royalty Relief Act in 1995, a price threshold was included on each deepwater lease's addendum starting in 1996 and 1997 while a final rule was developed.

"When the rule became final early in 1998, the staff, which had been used to putting the threshold in the addendum, assumed it would be in the lease. But the director of the offshore program decided that it should continue to be in the addendum. That was not communicated to the staff," she said.

Deputy Interior Sec. P. Lynn Scarlett said after the omission was discovered, price thresholds were included on federal deepwater leases starting in 2000.

"With respect to any renegotiation of past leases, we do not have authority in a mandatory way to do that. Instead, we appealed to companies to come in and discuss renegotiation. That process is under way," Scarlett said.

She said the omission and other errors occurred during President Bill



Clinton's administration. "In 2001, we inherited 170 weaknesses in program and financial controls. Four more have been identified since, but the 170 that were there have been corrected," she said.

Cover-up allegation

Several committee members seemed more concerned with what they felt may have been a cover-up by DOI and MMS employees until the omission was reported in the New York Times early this year.

"Had they notified officials and amended the contracts when the omissions were discovered, they could have corrected the problem at no cost to the companies or the public. Instead, they chose to cover it up," said Darrell E. Issa (R-Calif.), chairman of the committee's Energy and Natural Resources Subcommittee, which conducted its own 7-month investigation.

"I didn't know about it because I arrived at MMS in 2002, 4 years after it happened," Burton said. "The people who knew about it were no longer there. I don't think others realized they needed to tell me about it. I did not review all the contracts that were issued before I arrived at the department. There was no reason for me to ask about those specific years. I had no reason to believe there was anything wrong with them."

Burton said the only correspondence from the period that she has found since was a letter that Carolita U. Kallaur wrote to a leaseholder in 2001 when she was associate MMS director for offshore minerals management. It explained that price thresholds were reinstated a year earlier because the Deepwater Royalty Relief Act required them.

Kallaur retired from MMS and DOI on Feb. 11, 2002, and she since has died, Burton said.

Burton said that after the omissions became public earlier this year, 20 leaseholders contacted MMS and 10 began renegotiations to put price thresholds on their 1998-99 leases as addendums. "Shell Oil [Co.], is very close to signing an agreement. BP [PLC], is not far behind. These are major deepwater leaseholders. One of the reasons this takes time is that these companies have several partners who also have to agree," she said.

More pressure

Rep. Edward J. Markey (D-Mass.) contends that more pressure should be put on leaseholders to renegotiate terms. Rep. Maurice Hinchey (D-NY) and Markey cosponsored an amendment to DOI's annual appropriation that bars oil and gas producers from receiving future federal leases if they hold 1998-99 deepwater leases and

are unwilling to renegotiate (OGJ, June 12, 2006, p. 30). The House passed the amendment, he said, and the Senate has passed similar legislation.

"The administration and Interior Department have opposed this amendment, seeking instead to cajole oil companies to come back to the table," Markey said. "This is simply trying to continue to work with bad actors."

Scarlett said, "The administration has significant concerns about mandatory renegotiation. These contracts, like all contracts, reside at the bedrock of a reliable federal government. It's very important that we uphold their sanctity so the federal government can be seen as a reliable business partner."

"Simply shining a light on this is putting pressure on these companies, which report record profits, to come back to the negotiating table," suggested Rep. Tom Davis (R-Va.), the committee's chairman. But he also warned that Congress might have to step in if more producers don't come forward.

Rep. Dennis J. Kucinich (D-Ohio) recommended more aggressive actions:

"These leases should be canceled. There also should be a criminal investigation of those who were responsible for these omissions and the cover-up. How can we sit still and accept that something which cost the American people billions of dollars was simply a mistake?" ✦

DOT proposes extending low-pressure oil pipeline rules

Nick Snow
Washington Correspondent

The US Department of Transportation has proposed stiffened safety requirements, including cleaning and continuous monitoring, for more than 1,200 miles of crude oil and product pipelines.

If adopted, the regulations would place another 684 miles of domestic onshore oil pipelines, primarily operated by major firms, under federal regulation. Comments will be accepted for 60 days following the Aug. 31 announcement.

The department's Pipeline and Hazardous Materials Safety Administration (PHMSA) was already preparing the proposed rules when leaks were discovered late last winter in BP Exploration (Alaska) Inc.'s crude oil gathering lines at Prudhoe Bay oil field in Alaska.

PHMSA issued orders to the company to more closely monitor and maintain the low-pressure system on Mar. 2, which it later amended with additional requirements. Meanwhile, the company found and identified leaks elsewhere in its Prudhoe Bay system and announced that it would have to cut as much as 200,000 b/d of shipments while repairs were made.

Three congressional committees scheduled hearings this month on the leaks and subsequent system shutdowns, starting with the House Energy and Commerce Committee on Sept. 5 and continuing with the Senate Energy and Natural Resources Committee on Sept. 12 and the House Transportation and Infrastructure Committee on Sept. 13.

Acting Transportation Sec. Martha Cino said the proposed regulations would require operators of low-pressure pipelines at Prudhoe Bay and other unusually sensitive areas to meet requirements similar to the ones PHMSA applies to high-pressure pipelines.

"This rule will help restore confidence in America's pipelines," she said, adding that it would have prevented maintenance lapses that led to BP's partial system shutdown in Alaska.

Existing regulations

PHMSA already regulates gathering lines in populated areas and in rural areas of Gulf of Mexico inlets. It also regulates low-stress lines in populated areas or that cross commercially navigable waterways, as well as any line carrying hazardous liquids.

The agency decided that additional onshore low-stress pipelines in rural areas, which were exempted when the original regulations were formulated in 2000, needed to be included after leaks were reported.

It received a set of proposals from the American Petroleum Institute and the Association of Oil Pipelines in July. Their recommendations included leak detection measures appropriate to each pipeline, employee training for abnormal operating events, well-marked routes, more programs to reduce the chance of excavation damage, and prompt reporting of incidents.

Other proposals recommended establishing a 5-mile buffer zone separating low-pressure oil pipelines from public drinking water sources and a 1-mile buffer from an environmentally sensitive area. PHMSA rejected the idea, proposing a ¼-mile buffer instead after its data showed the largest onshore spill from an oil pipeline traveled no farther than 2 acres.

The proposed regulations would cover oil pipelines between 6⅝ and 8⅝ in. in diameter operating above 20% of specified minimum yield strength (SMYS) in areas designated "unusually sensitive." The proposals noted that a pressure of 125 psig approximates 20% SMYS for steel pipe of unknown stress level, based on minimum weight pipe 8 in. in nominal diameter with 24,000 psi yield strength.

DOT and PHMSA are seeking comments within 60 days on whether the proposed pressures and buffer zone are adequate.

Primary threats

The proposals also focus on corrosion and third-party excavation damage as the primary threats to rural oil pipe-

line integrity. Operators would have to continuously monitor systems, but DOT and PHMSA are seeking comments on a proposal to require low-pressure line operators to submit the annual reports and accident reports PHMSA makes other oil pipeline operators prepare.

The proposed regulations would cost an estimated $5 million initially, $2 million/year from the second through seventh years and $1 million/year after the seventh year, DOT said in its proposed rulemaking notice.

It said that PHMSA determined that smaller independent producers would not be affected following consultations with the Independent Petroleum Association of America and the US Small Business Administration.

The Pipeline Safety Trust immediately called DOT's proposals inadequate because they would apply to only 17% of the currently unregulated low-pressure oil pipelines nationwide.

Carl Weimer, executive director of the Bellingham, Wash.-based nonprofit organization, said PHMSA pushed the proposals out "presumably to avoid uncomfortable, ongoing questions by Congress and the media."

He called them "so technically deficient [with] such narrow pipeline coverage that uncomfortable questions to PHMSA need to continue." He said, "Contrary to a statement in the proposal, the rule will not improve public confidence in pipeline safety since the agency has continued to exempt the vast majority of these types of problem pipelines."

Shipments rise

Meanwhile, BP Exploration Alaska reported on Aug. 29 that shipments through its Prudhoe Bay gathering system were back above 200,000 b/d following completion of repairs to its Gathering Center 2 compressor. It also said it has found no additional integrity problems after completing ultrasonic inspections of about 2,500 ft of pipe in the Eastern Operating Area and 5,300 ft of pipe in the Western Operating Area.

While more than 15,000 ft of insulation has been stripped from eastern-area oil transit lines, BP Exploration Alaska said it temporarily stopped removing insulation from the western-area lines because it contains asbestos. The line will continue to operate while it evaluates possible worker exposure problems, it said.

The company has completed orders for 16 miles of replacement pipeline, which it expects to receive from US mills during 2006's fourth quarter. BP's West Coast refining and marketing system remains adequately supplied for the short term, and no disruptions of crude oil or fuel supplies are expected. ✦

Aramco head says technology is key to boosting reserves

For the oil industry to continue meeting its long-term responsibility of providing energy to the world economies, it needs to continue to identify new oil fields, said Saudi Aramco Pres. and Chief Executive Abdallah S. Jum'ah.

This is just one of "five technology targets" critical for the industry to maintain its obligation, said Jum'ah during a panel discussion on technology and future energy supplies at the Third OPEC International Seminar.

He believes that industry professionals could find trillions of additional barrels of producible potential through continued technological advances, and challenges the industry to add 1 trillion bbl of oil to world reserves over the next quarter-century.

The second technology target is to increase oil recovery rates from known fields. Over the next 25 years, increasing incremental recovery rates for existing fields by 20% is feasible, Jum'ah said. This would add another trillion barrels of oil to the world's reserves base, he said.

Jum'ah said the third technology target—reducing exploration and production costs—would turn prospects that were previously uneconomically viable into attractive investment opportunities.

Target four is development of unconventional oil resources. Jum'ah said extra-heavy oil, tar sands, and bitumen account for about 4.7 trillion bbl of oil in-place, which is already being exploited. Other unconventional sources include oil shales, which Jum'ah said pose even more thorny challenges, but with the potential for over 2.5 trillion bbl of oil cannot be ignored.

The fifth technology target underscored each of the other four and concerns lightening the environmental footprint of the industry's activities and of its products, Jum'ah said.

He added that if technology is not turned toward the environmental issue with as much urgency as it is toward exploration and production challenges, the oil industry could find itself with fewer places to look for energy.

In light of these technology targets, Jum'ah said that he believes about 2 trillion bbl can be added from yet-to-be-discovered fields and increased recovery rates over the next 25 years. And 1.5 trillion bbl can be extracted from nonconventional sources using current technology. Add these, he said, to the 1.2 trillion bbl of current proven reserves, and the total potential is for over 4.5 trillion bbl.

"That number," Jum'ah said, "translates into more than 140 years of supply at today's current rate of consumption." ✦

First flow test buttresses estimates of gulf's Lower Tertiary potential

Rising confidence in discovering and producing oil and gas from deep Lower Tertiary formations in the deepwater Gulf of Mexico could make a large but costly impact on US reserves, Devon Energy Corp. said in early September.

Even with the play still in its infancy, industry is estimating that it might ultimately recover 9-15 billion bbl of oil equivalent. US proved crude oil reserves are 21.4 billion bbl. The play area covers more than 10 million acres, much of it near Mexican waters.

Devon, which entered a joint venture to explore the play with Chevron Corp. in September 2002, expects four discoveries in which it has participated to add 300-900 million bbl of oil equivalent to the company's resource base. It has booked no reserves so far but expects production to start in 2009.

The industry overall has made 12 discoveries in 19 wells drilled in the trend for a 63% geologic success rate (Fig. 1, Table 1).

Devon, which holds interests in 273 blocks in the Lower Tertiary trend, plans to participate in or drill at least 19 other prospects in the next 3-5 years that have a combined 2-5 billion boe in unrisked exploration potential (Fig. 2).

Extended test

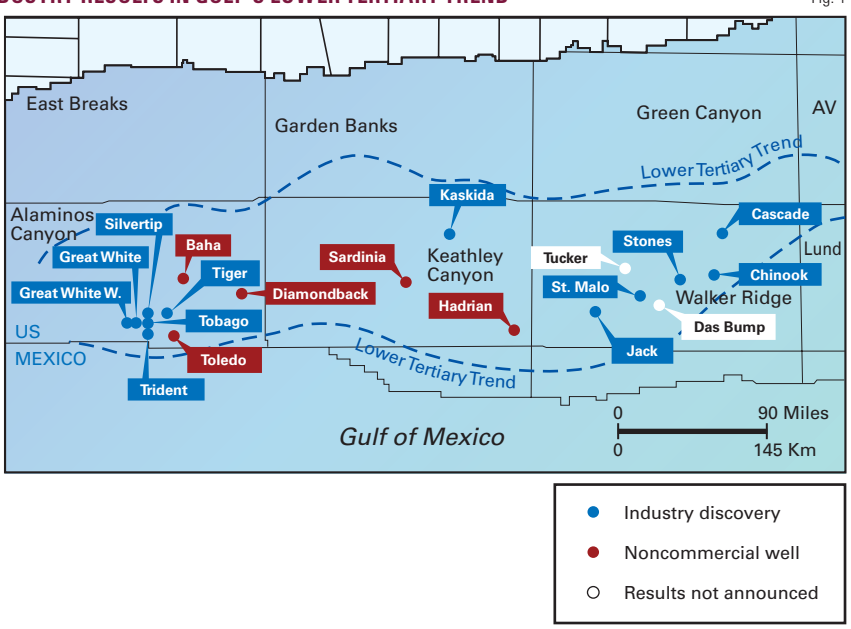
Chevron, Devon, and Statoil ASA just completed the only extended well test of a Lower Tertiary well to date. The Jack-2 well in Walker Ridge Block 758 sustained flow rates of more than 6,000 b/d of oil from 40% of the total measured net pay of more than 350 ft.

The test set several world records even though the test equipment capacity led to the decision to test only 40% of the net pay. The well is 270 miles southwest of New Orleans.

Chevron said the well test set several records for test equipment pressure, depth, and duration in deepwater (Fig. 3). Perforating guns were fired at world record depths and pressures. The test tree and other drillstem test tools set world records, helping the operating

INDUSTRY RESULTS IN GULF'S LOWER TERTIARY TREND

Fig. 1



Source: Modified after Devon Energy Corp.

group conduct the deepest extended drillstem test in deepwater Gulf of Mexico history.

More than 99% of Gulf of Mexico production has come from Tertiary Pleistocene, Pliocene, and Miocene formations. As recently as the early 2000s, few observers believed that the Lower Tertiary sands would be present or productive at great depths, Devon noted.

String of discoveries

Chevron and partners made the initial Jack field discovery in September 2004.

The extended drillstem test took place in the second quarter of 2006 at Jack-2, an appraisal well drilled in 2005 that encountered thicker net pay than the discovery well.

The four discovery wells in which Devon has participated—Cascade, Jack, Kaskida, and St. Malo—went to total depths of 27,929 ft to 32,500 ft. They are in 5,800-8,200 ft of water.

Demonstrating the play's relatively early stage, Cascade, Jack, and St. Malo are the only three of the 12 industry discoveries to have more than a single penetration, Devon said.

Kaskida, on Keathley Canyon Block 292, cut more than 800 ft of net hydrocarbon-bearing sands (OGJ Online, Aug. 31, 2006). It may be the best of industry's 12 discoveries so far in the play, Devon said.

Devon initially held 20-25% working interests in the four discoveries, but it holds 43% average working interest in the 19 identified prospects.

Reservoirs and development

Devon declined to provide technical information on oil quality and reservoir parameters.

It said that it has seen no undue complexity in either but that the reservoirs are very different from one another. It also didn't define the oil:gas ratio of the reservoirs but implied they are oil-dominant.

Salt is a prominent feature in the play. Two play types in the 19 prospects are four-way closures under salt and three-way closures against salt, Devon said. The subsalt type is dominant.

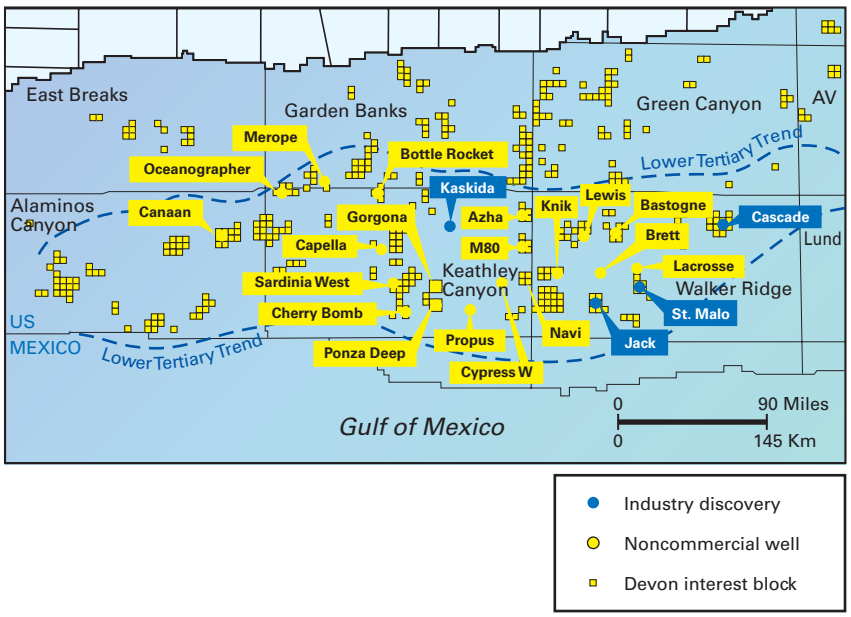
Two thirds of the 19 prospects are in Keathley Canyon, but not all have reached drillable status, the company said.

Devon said it acquired more than half of its 19 identified prospects at US Minerals Management Service lease sales.

Chevron and Devon are discussing development plans and potentially the first use in the gulf of floating production, storage, and offloading vessels

DEVON ENERGY'S LOWER TERTIARY DISCOVERIES, IDENTIFIED PROSPECTS

Fig. 2



Source: Modified after Devon Energy Corp.

INDUSTRY'S LOWER TERTIARY DISCOVERIES IN THE GULF

Table 1

Year	Present operator	Discovery	Block	Water depth, ft
2006	BP	Kaskida	Keathley Canyon 292	5,860
2005	BP	Stones	Walker Ridge 508	9,576
2004	Chevron	Jack	Walker Ridge 759	6,965
	Chevron	Silvertip	Alaminos Canyon 815	9,226
	Chevron	Tiger	Alaminos Canyon 818	9,004
	Chevron	Tobago	Alaminos Canyon 859	9,627
2003	BHP Billiton	Chinook	Walker Ridge 469	8,831
	Chevron	St. Malo	Walker Ridge 678	7,036
2002	Devon	Cascade	Walker Ridge 206	8,143
	Shell	Great White*	Alaminos Canyon 857	8,717
2001	Chevron	Trident	Alaminos Canyon 903	9,743

*Information not announced on Great White West.

TransOcean's Cajun Express semisubmersible was on hand for the Jack-2 drillstem test in June 2006.

with the MMS. Many of the discoveries are remote from oil pipelines.

Early-stage figures on field development costs are $80-120 million/well plus as much as $1.3-1.5 billion for subsea facilities, Devon said.

Near-term plans are to appraise Kaskida in late 2006, drill more appraisal wells on Jack and St. Malo in 2007, and obtain formal approval of the Cascade deepwater operating plan.

Cascade, leading candidate to become the first Lower Tertiary trend field to be placed on production, went to TD 27,929 ft in 8,143 ft of water on Walker Ridge Block 206.

Chevron noted that it is the largest lease holder in the deepwater Gulf of Mexico and in the emerging Lower Tertiary trend. ✦

Benin

The Ministry of Mines, Energy and Water launched a late 2006 bid round by reoffering two land and two deepwater blocks.

Coastal blocks A and B and deepwater blocks 5 and 6 are in the Benin coastal sedimentary basin. Bid deadline is Nov. 30, 2006.

Gambia

Buried Hill Energy (Cyprus) PLC, London, said its Gambia subsidiary entered into 30-year licenses on the A1 Alhamdulilah and A4 blocks in the Atlantic off Gambia.

The acreage, separated from Mauritania by the Senegalese coast, is considered to have high potential for discoveries, the company said.

Kazakhstan

Big Sky Energy Corp., Calgary, said its Kazakh subsidiary plans 3-month production tests of as many as three zones at a pool discovery on the Dauletaly Block in Atyrau Province 265 km east of Atyrau.

Logs from KoZhaN LLP's DLT-33 well, drilled to TD 875 m to test Lower Cretaceous and Upper Jurassic sands, showed four oil-bearing sands 1.5 to 10 m thick with 28-34% porosity and 70-82% oil saturation.

Syria

Gulfsands Petroleum PLC, Houston, plans to spud Tigris-1 on the Tigris prospect in Block 26 underlying Souedieh oil and gas field. The vertical well is projected to 4,500 m.

Tigris-1 will be the second well to penetrate the Carboniferous and Devonian aged reservoirs on the structure, said 50% partner Emerald Energy PLC, London. Syrian Petroleum Co.'s S1100 well 1 km northeast of Tigris-1 found a substantial hydrocarbon column in 1994, according to independent interpretation of wireline logs.

Gulf of Mexico

Petroleum Geo-Services ASA is to begin gathering 9,345 sq km of multiclient 3D seismic data in the Gulf of Mexico starting in October 2006.

The survey, with BP America Inc. as the primary financial and technical partner, will cover 401 deepwater blocks in the Garden Banks, Keathley Canyon, Green Canyon, and Walker Ridge areas. The project has above-average prefunding for the Gulf of Mexico, PGS said.

The Ramform Viking and two other vessels will use state-of-the-art wide azimuth towed streamer technology. Acquisition will take 12 months, and data will be available for the March 2008 federal lease sale.

Ghana

The government awarded Tullow Oil PLC, London, operated interests in the Shallow-water and Deepwater Tano blocks along the marine boundary with Ivory Coast. Tullow took a farmout to acquire a 22.9% interest in the adjacent West Cape Three Points offshore license. Its other interests are 85.5% in the Shallow-water Tano block and 49.95% in Deepwater Tano.

The company, which sees Albian and Upper Cretaceous potential on the Tano blocks, will try to commercialize one or more of three undeveloped oil and gas discoveries on Shallow-water Tano.

The three licenses are in the Greater Ivoirian basin on trend with Espoir oil and gas field off Ivory Coast, in which Tullow holds 21.33% interest.

Mississippi

Odyssey Petroleum Corp., Vancouver, BC, reported a recompletion in Pelahatchie field, Rankin County, that flowed at the rate of 450 b/d of 48° gravity oil with 420 psi pressure on a $^{20}/_{64}$-in. choke.

Producing zone is Cretaceous Rodessa at 10,498-508 ft.

The well is to be produced on a $^{7.5}/_{64}$-in. choke at an anticipated rate of 120-150 b/d. The company plans to drill new wells and recomplete more wells in the field, which has produced from multiple formations from 7,500 ft to 17,000 ft.

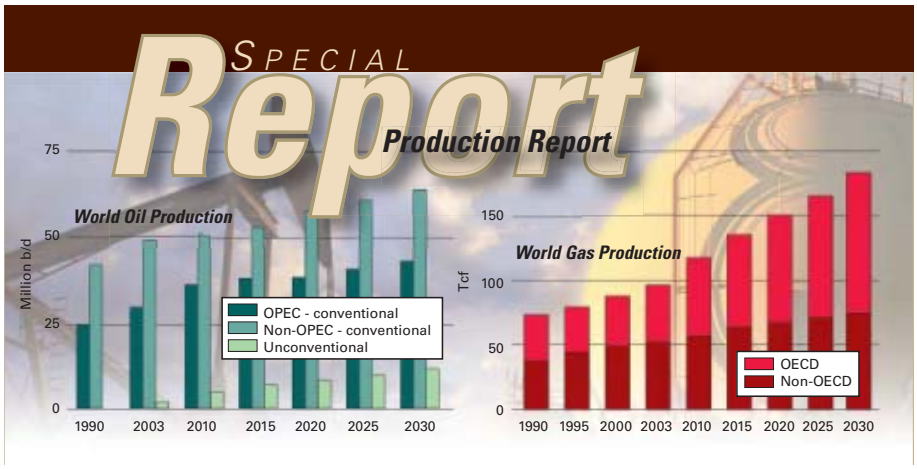
Texas

South

EnCana Oil & Gas (USA) Inc., Calgary, plans to spud an exploratory well to overpressured Cretaceous Pearsall shale shortly in Maverick County of South Texas, said 50-50 partner The Exploration Co., San Antonio.

Historic recovery has averaged 475 MMcf/well from 49 vertical Pearsall wells, almost all of them in Los Cuatros field, where Pearsall lies at about 6,800 ft. Those wells were drilled without benefit of 3D seismic data or advanced drilling and fracturing techniques, TXCO said.

Meanwhile, TXCO is refurbishing a 900-hp drilling rig rated to 9,500 ft and plans to field it shortly in the Maverick basin, where it is capable of operating in all company-operated plays.



Alberta bitumen output to triple in next 10 years

Guntis Moritis
Production Editor

Forecasts show that bitumen production in Alberta from oil sands will almost triple in the next 10 years as many new projects come on stream.

Companies continue to lease many potential oil sands areas in Alberta that may hold 173.7 billion bbl of remaining established reserves of bitumen, according to the latest Alberta Energy and Utilities Board (EUB) estimates.[1]

A variety of companies has secured acreage in the three areas in Alberta that have the most potential: Athabasca, Peace River, and Cold Lake (Fig. 1). Together, these three areas cover about 54,000 sq miles.

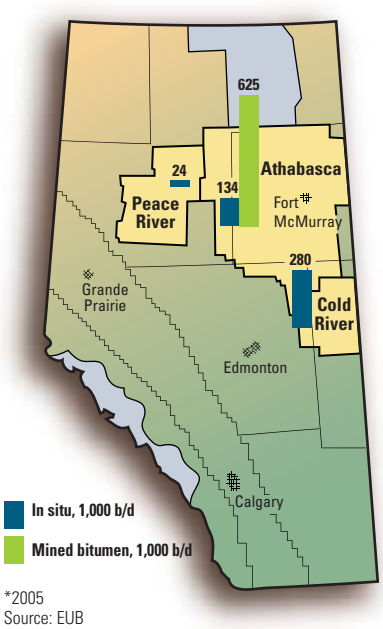
Some companies, such as Petro-Canada, have established thermal in situ oil sands production and are partners in surface-minable projects already and have additional projects planned for their lease holdings using either more thermal in situ, such as steam-assisted gravity drainage (SAGD), or surface mining. Other companies without current bitumen production, such as North American Oil Sands Corp., have in the last few years leased large amounts of acreage and have plans to start bitumen production, also with SAGD.

Recent entrants to the area include Korea National Oil Corp., South Korea's state-owned oil company, which recently bought in the Cold Lake region the Blackgold Mine from US-based Newmont Mining Corp. and has plans to produce about 35,000 b/d for 25 years, starting in 2010 with SAGD.

Some in situ projects produce bitumen through primary pumping methods, but most projects require thermal stimulation to recover the bitumen. Cyclic steam injection and SAGD are the most common thermal methods.

Also because of the high cost of natural gas, various companies have ongoing pilots and research projects for including solvents in the recovery pro-

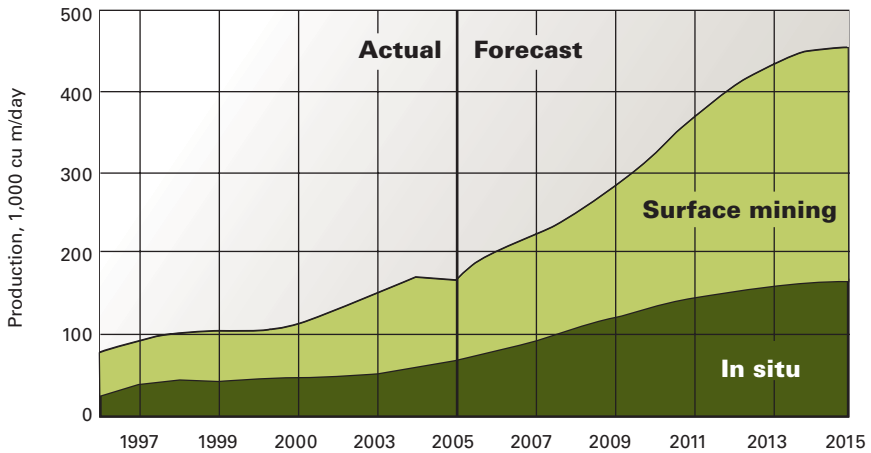
ALBERTA BITUMEN PRODUCTION* Fig. 1



*2005
Source: EUB

ALBERTA BITUMEN PRODUCTION

Fig. 2



Source: EUB

cess either included with the steam or in a vaporized form (Vapex) that could lower production costs.

The SAGD process typically involves drilling two horizontal laterals, one about 5 m above the other. Steam injected into the top lateral forms a steam chamber that heats the bitumen that flows into and is produced from the lower lateral.

The plans of both North American and Petro-Canada illustrate the types of projects that will begin during the next 10 years in Alberta's oil sands.

Reserves estimates

EUB in its latest reserves and outlook report estimated that Alberta's oil sands contained 1.69 trillion bbl of bitumen in place and have produced 5 billion bbl through 2005. Of the 173.7 billion remaining established reserves, the report said 10.2 billion bbl are under active development.

For calculating reserves from minable areas, EUB uses a combined mining and extraction recovery factor of 82%. It says this recovery factor reflects the combined average loss of 18% of the in-place volume by the mining operations and the extraction facilities. The recovery factor leads to its calculated 31.7 billion bbl of remaining established minable crude bitumen reserve as of yearend 2005, of which about one-quarter is under active development.

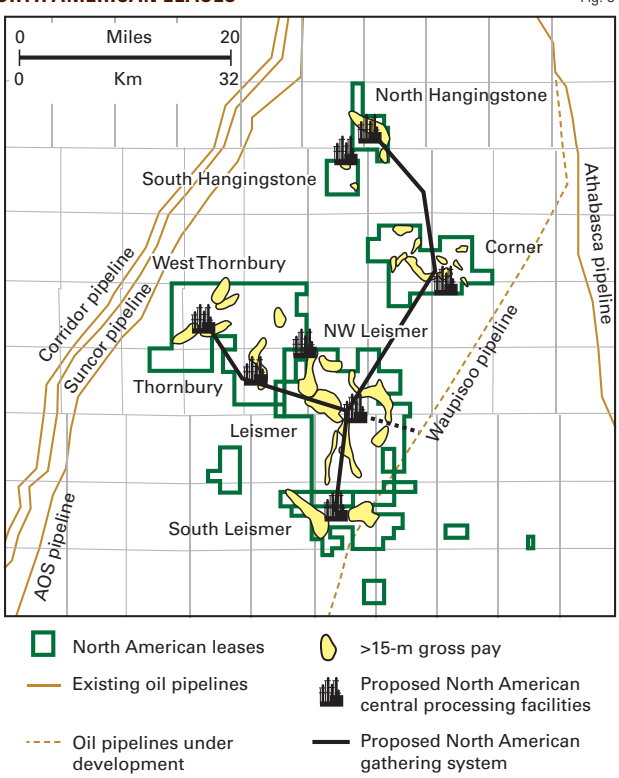
EUB based its estimated in situ initial established reserves on a minimum 10-m zone thickness in all zones except for the Wabiskaw zone in the Athabasca area, in which it used a 15-m cutoff. For primary recovery processes, it used a 3-m cutoff. Another of its criterion was a minimum saturation cutoff of 3% by mass in all deposits except for Athabasca and Cold Lake, in which it used a 6% cutoff.

For determining recoveries in areas outside of the active projects, it applied nominal recovery factors of 20% for thermal development and 5% for primary projects.

EUB estimated that the areas under active development held 2.6 billion bbl of remaining established reserves. It based these reserves on nominal recovery factors of 5% for primary schemes, 25% for thermal in the Cold Lake area, 40% for thermal in the Peace River area, and 50% for thermal in the Athabasca area.

NORTH AMERICAN LEASES

Fig. 3



Production forecasts

EUB forecasts that bitumen production for both mined and in situ bitumen will increase to 2.9 million b/d from 1.06 b/d in 2005 (Fig. 2). The mined portion increases to 1.8 million b/d from 625,000 b/d in 2005, while in situ production increases to 1.1 million b/d from 438,000 b/d in 2005.

In 2005 about 8,000 wells in Alberta produced in situ bitumen at an average 57 b/d/well. The in situ and primary projects through yearend 2005 have produced 1.6 billion bbl of bitumen.

Operators of the three producing mining projects are Suncor Energy Inc., Syncrude Canada Ltd., and Albian Sands Energy Inc. Through yearend 2005, these projects had recovered

Option 1:

Cementing and perforating

1 Run production casing into wellbore to bottom of hole
2 Rig up cementing equipment and cement head
3 Condition and circulate mud
4 Mix spacer and chemical wash
5 Drop bottom plug
6 Pump chemical wash and spacer ahead of cement
7 Mix cement and pump cement
8 Drop top plug and displace
9 Bump plug
10 Wait on cement
11 Rig up perforating equipment
12 RIH with perforating guns
13 Correlate and position guns across zone of interest
14 Fire charges
15 POH with perforating equipment

The hard way

Option 2:

Swellpacker™ Isolation System

1 Gauge OD of packer
2 Run in hole with pre-drilled liner
3 Produce well

The easy way

Zonal isolation with Swellpacker™ isolation system.

Performance without compromise.

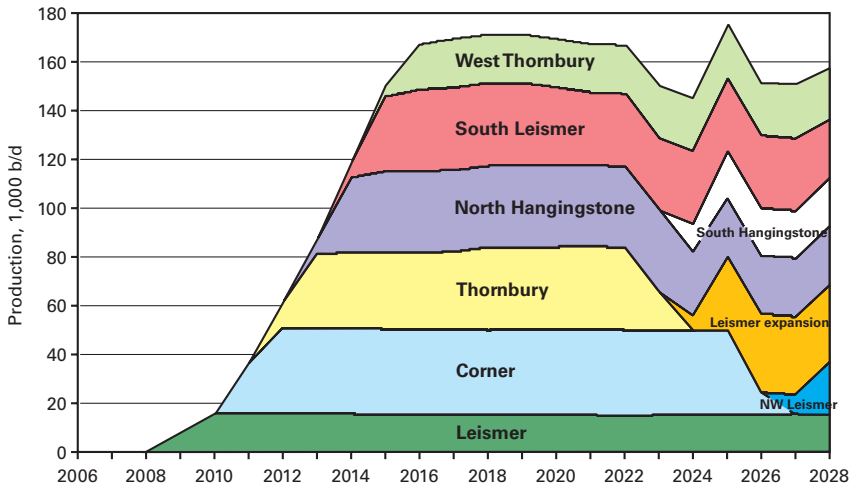
Visit us at www.easywell.com/swellpacker.

easywell

HALLIBURTON
Production Optimization

NORTH AMERICAN SAGD PRODUCTION

Fig. 4



3.7 billion bbl of bitumen.

EUB included the following projects for estimating future bitumen recovery from mining projects:

- Suncor's existing production and expected expansions, including Voyageur.
- Syncrude's existing and expected expansions, including Stage 3 and Stage-3 debottleneck of the four-stage project that began in 1996.
- Albian Sands debottlenecking projects and expansions scheduled for completion by 2011.
- Canadian Natural Resources Ltd.'s (CNRL) Horizon project, approved by EUB in January 2004, with production starting in 2008.
- Shell Canada Ltd. Jackpine Mine Phase 1, approved by EUB in February 2004, with production expected 2 years after the Muskeg mine expansion in 2011.
- Petro-Canada's Fort Hills project, approved by EUB in October 2002, with production starting in 2011.
- Imperial Oil Ltd.'s and ExxonMobil Corp.'s Kearl mine, with start-up planned for 2010.
- Total E&P Canada Ltd.'s Joslyn North Mine, expected to start producing in 2010.
- Synenco Energy Inc.'s Northern Lights mining and extraction with an initial start in 2010.

The EUB report did not list specific projects used in its in situ bitumen production forecast.

North American

North American Oil Sands Corp. plans to develop a SAGD project in acreage that it has acquired in the last 2 years.

Formed in 2001, North American now employs about 42 people. Major shareholders of North American include Paramount Resources Ltd., ARC Energy Funds, and the Ontario Teachers' Pension Plan Board. ARC is a Calgary investment company and the Ontario Teachers Pension Plan is Canada's second-largest pension manager.

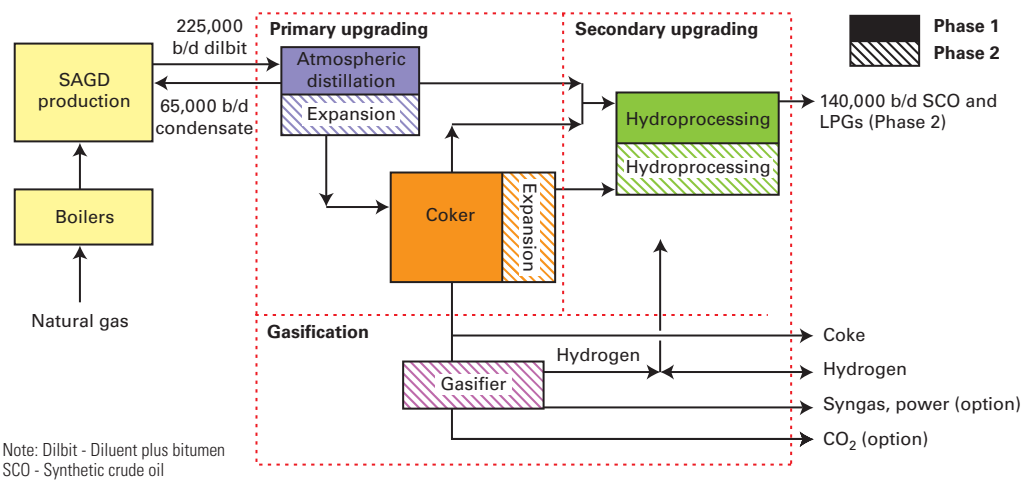
North American's planned Kai Kos Dehseh project includes an upgrader in Edmonton to handle a maximum 160,000 bo/d of bitumen production by 2015.

The company holds interest in 226,560 gross acres of oil sands leases that contain an estimated 1.2 billion bbl of P50 (50% probability) resources, according to calculations made for the company by GLJ Consultants. Its holdings are in four core areas: Leismer, Corner, Hangingstone, and Thornbury that are surrounded by other company SAGD projects in various stages of completions (Fig. 3).

"The leases are geographically concentrated to achieve critical mass, but benefit from risk diversification provided by reservoir variability," according to Mike Langley, senior vice-president business development, for North American Oil Sands Corp.

NORTH AMERICAN UPGRADER

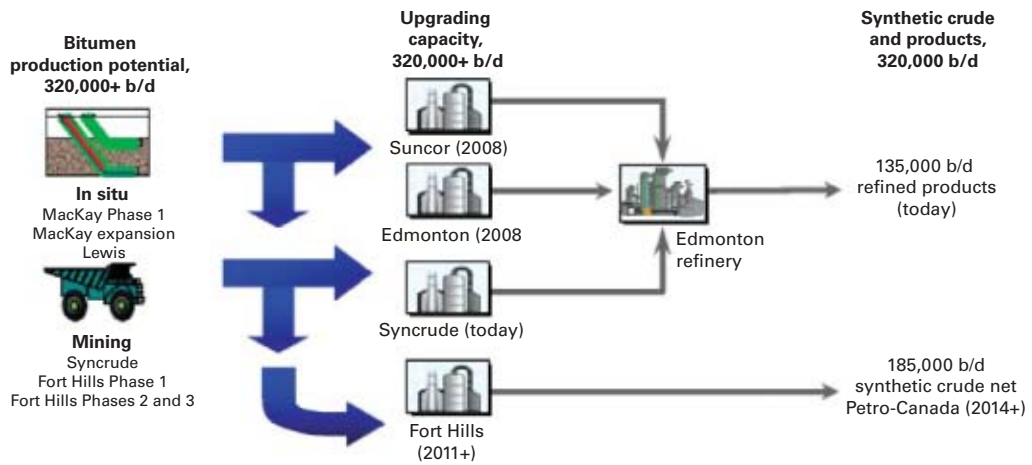
Fig. 5



Note: Dilbit - Diluent plus bitumen
SCO - Synthetic crude oil

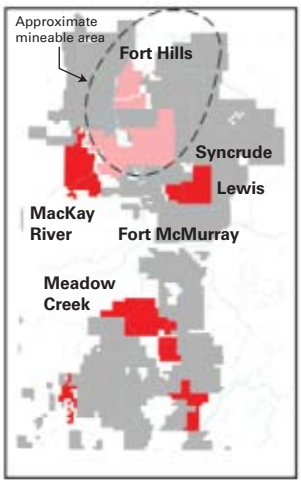
INTEGRATED OIL SANDS STRATEGY

Fig. 6



PETRO-CANADA RESOURCE POTENTIAL

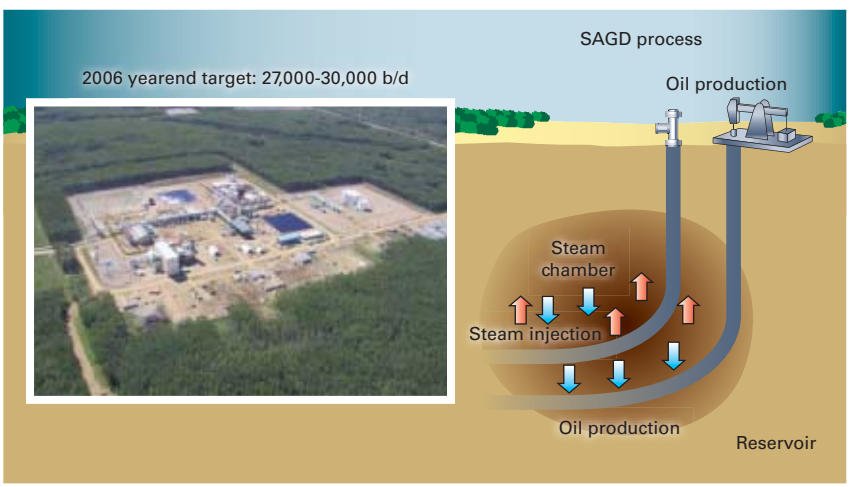
Fig. 7



Mining	Petro-Canada interest	Resource, billion bbl
• Syncrude	(12%)	1.1
• Fort Hills	(55%)	1.6
SAGD		
• MacKay River	(100%)	0.3
• MacKay River expansion	(100%)	0.6
• Lewis	(100%)	3
• Meadow Creek	(75%)	1.3
• Other		2.1
Total		**10 billion bbl**

MACKAY RIVER SAGD

Fig. 8



Langley told OGJ that "most good areas in the oil sands areas are already under lease, with mostly speculative acreage remaining." He added that North American has accumulated acreage since 2004.

North American's planned projects include five distinct SAGD facilities and four smaller satellite hubs. Each hub will have a central processing facility for steam generation and bitumen processing and several phases of well development, as is typical for most SAGD projects, that will maintain each facility at capacity for the life of the projects.

North American plans a stepped development program that starts with 10,000 bo/d production from the Leimer lease in 2008-10 (Fig. 4).

Its two-phase upgrader program will allow production from the other leases to reach 80,000 b/d in 2011 and 160,000 b/d by 2015. Phase 1 of the upgrader will include coking and hydrotreating, Phase 2 will include coking, hydroprocessing, and coke gasification (Fig. 5).

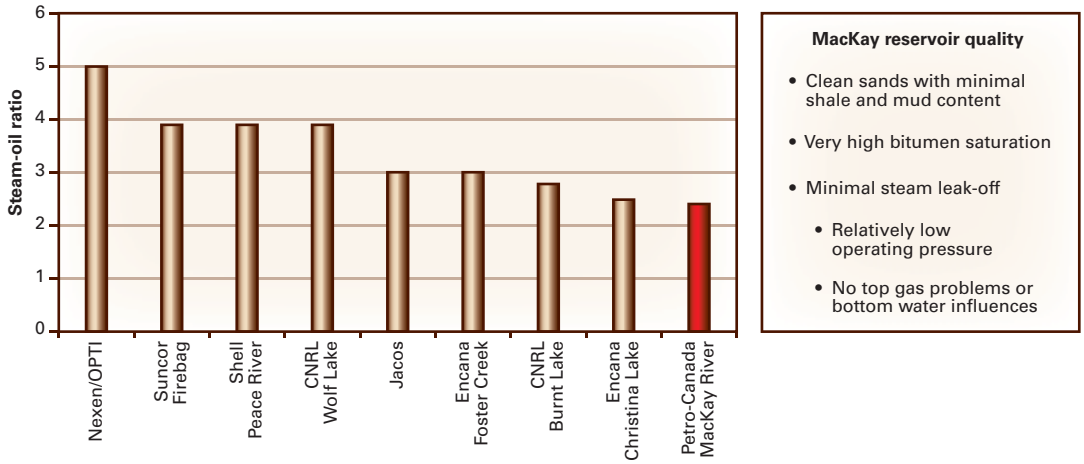
As with most upgraders, the upgrader will process the extra-heavy crude into refinery-ready synthetic crude oil that can be processed into gasoline, diesel, and other fuels. North American plans to locate the upgrader near Edmonton to allow easy access markets for the products.

Langley said the company has delineated its leases with 121 wells boreholes and uses a 15-m cut off to determine producing formation. He expects recovery factors from the leases of 40-50%, based on results from established nearby SAGD projects.

North American also will test solvents to see if they improve SAGD

ENERGY USE

Fig. 9



Note: Nexen - Nexen Inc.; OPTI - OPTI Canada Inc.; Shell - Shell Canada Ltd.; Jacos - Japan Canada Oil Sands Ltd.; EnCana - EnCana Corp.

recovery. Langley said North American will be able to obtain the solvents from its upgrader, once it is completed.

Water for the steam will come from more saline water found in deeper formations.

Langley sees no problem in obtaining natural gas for steam generation, but he said that the company will also be looking a lower cost power alternatives such as gasification of the heavy ends produced in the upgrader. The carbon dioxide from the gasification process has the potential use for enhancing oil recovery in many oil fields in Alberta, he added.

Langley expects government approval of North American's plans by yearend 2006.

Petro-Canada

Petro-Canada has an integrated strategy for producing its oil sands resources (Fig. 6). Its plan expects to produce up to 320,000 b/d of synthetic crude and refined products after 2014.

The plan combines upgrading capacity at Syncrude and Edmonton with a processing agreement at Suncor to produce 135,000 b/d of ultra-low sulfur refined products for its existing Edmonton refinery.

Included in the plan is a new upgrader outside Edmonton for upgrading bitumen from the Fort Hills mine. Petro-Canada's share of the Phase 1 of the upgrader will be about 80,000 b/d. It also expects subsequent upgrader expansions as more bitumen becomes available.

Neil Camarta, senior vice-president for oil sands operations of Petro-Canada estimated that the company has about 10 billion bbl of recoverable bitumen in both its minable and in situ resources (Fig. 7).

He said Petro-Canada uses a 90% recovery factor for its mines and 50+% recovery factor if "the dirt is good" to estimate resource potential.

Petro-Canada has a 12% interest in Syncrude that produces 350,000 b/d and is the world's largest integrated mining and upgrading operation. Syncrude has operated for more than 25 years and Petro-Canada says it has used its experience at Syncrude for designing its Fort Hills integrated mining and upgrader project.

The company also is one of the first to initiate a commercial SAGD project. Its MacKay River project has produced for the last 3-years and Petro-Canada expects to reach the target production of 27,000-30,000 b/d by yearend 2006 (Fig. 8).

The company notes that the 2.5 steam-to-oil ratio at MacKay is one of the best in the industry and credits the low ratio mostly to the high quality of sands with 80% bitumen saturation on the property (Fig. 9). Petro-Canada says operating costs at MacKay are in the range of $6 (Can.)/bbl of bitumen plus 1 Mcf of natural gas. At full production, it is targeting $4-5 (Can.)/bbl for costs other than gas.

Petro-Canada handles the environmental concern regarding water by recycling all water.

Petro-Canada's largest growth will come from the Fort Hills project that it and its partners UTS Energy Corp. and Teck Cominco Ltd. have target 2011 for first production. Petro-Canada estimates that the property has upside potential of recovering 2.8 billion bbl.

It expects the mine initially to produce between 100,000 b/d and 170,000 b/d, depending on the final configuration. Future expansions may increase production up to 400,000 b/d.

Petro-Canada will build its upgrader near to Edmonton to provide a better labor pool and lower construction costs. The upgrader will include delayed coking, the same as at Suncor and at its Edmonton refinery.

Petro-Canada expects to submit its commercial application for the Fort Hills project by yearend 2006 and expects a regulatory decision by late 2007, with construction lasting 3 years and first oil production starting in 2011.

The company has also several SAGD projects in its plans. An expansion at MacKay River, by 2010, will increase production by 40,000 b/d.

On its Lewis lease, it has evaluated the lease with 130 wells, or up to 8 wells/section in some areas. Canadian

sections are 1 mile square. From this work it estimates that the lease contains a potential 3 billion bbl of bitumen resources.

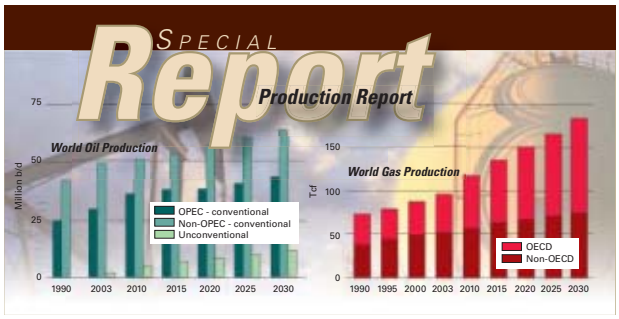
It has also delineated the Meadow Creek lease with eight wells/section.

For both Lewis and Meadow Creek, Petro-Canada has not announced a definite timetable to first production.

Camarta noted that in situ recovery requires about twice the energy to recover 1 bbl of bitumen as mining and that Petro-Canada is investing in a pilot project to find new ways to reduce energy needs. ✦

Reference

1. Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2005, ST98-2006, Alberta Energy and Utilities Board, May 2006.



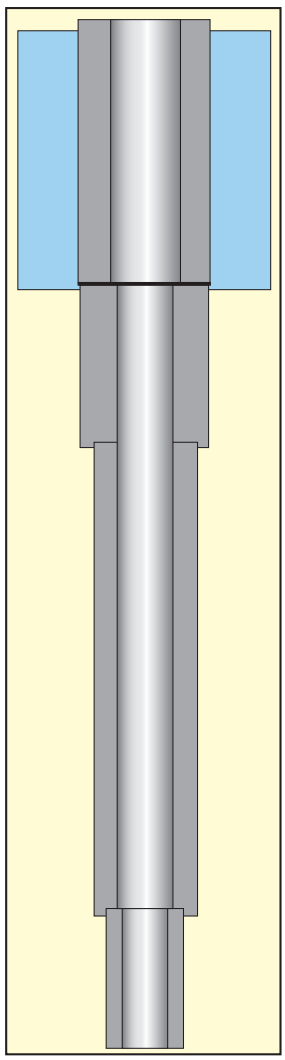
Deepwater fluid displacement needs special approaches

Syed Ali
Chevron Energy Technology Co.
Houston

Michael T. Darring
M-I SWACO
New Orleans

DRY-TREE WELL GEOMETRY

Fig. 1



TD/TDV, ft 24,951 / 23,502
Water depth/air gap, ft 6,262/93

Annular volume, bbl	1,444.0		Film thickness, in.	0.047	
Work string volume, bbl	441.4		Work string film volume, bbl	9.6	
Total volume, bbl	1,885		Annular film volume, bbl	31.9	
Steel volume, bbl	167.3				
Hole volume, bbl	2,052.6				

Length, ft	Casing OD, In.	Casing ID, In.	Work string OD, In.	Work string ID, In.				
6,310	11.750	11.000	5.500	4.670				
45	11.750	11.000	5.500	4.670				
3,845	11.750	11.000	5.000	4.276				
11,352	9.625	8.157	5.000	4.276				
30	9.625	8.157	4.000	3.340				
3,369	7.000	6.004	4.000	3.340				

Length, ft		Annular volume, bbl	Work string volume, bbl	Steel volume, bbl	Annular capacity, bbl/ft	Work string capacity, bbl/ft	Steel capacity, bbl	Hole capacity, bbl
6,310		556.3	133.7	51.7	0.088158	0.021186	0.008200	0.117544
45		4.0	1.0	0.4	0.088158	0.021186	0.008200	0.117544
3,845		358.6	68.3	25.1	0.093258	0.017762	0.006524	0.117544
11,352		458.1	201.6	74.1	0.040350	0.017762	0.006524	0.064636
30		1.5	0.3	0.1	0.049093	0.010837	0.004706	0.064636
3,369		65.6	36.5	15.9	0.019475	0.010837	0.004706	0.035018

Techniques that consider all the chemical and mechanical aspects of displacing drilling fluid can benefit dramatically the economics and effectiveness of well completions in deep water. Three critical components to consider include spacer design, wellbore cleanup efficiency, and fluid selection.

With day rates for deepwater rigs at unprecedented high levels, the time saved during fluid displacement can reduce overall project cost. A correctly engineered and executed displace-

ment operation avoids having to repeat the process to rectify chemical and mechanical problems that may occur during improperly designed transitions. Correct procedures are important especially in openhole completions.

Literature documents extensively the need of proper techniques for replacing drilling fluid with completion brine and thoroughly cleaning the wellbore.[1-4] An effective displacement is one that removes completely on the first attempt all drilling fluid, residual mud solids, and mud film trapped on the casing and tubular walls. Failure to do so can contaminate the completion fluid, risk mechanical problems, and restrict hydrocarbon flow.

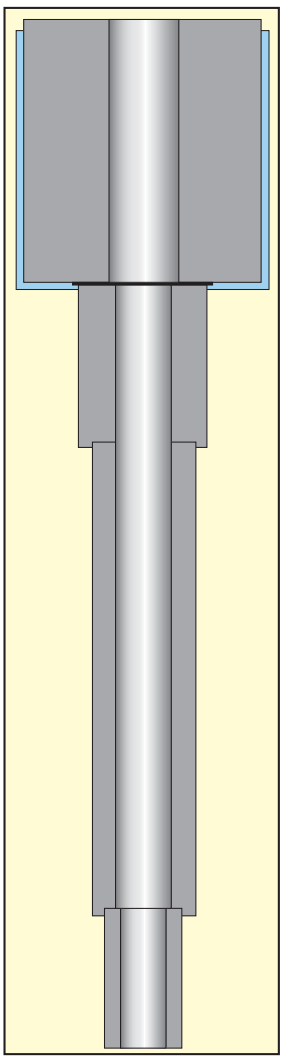
Repeating the process to correct inadequate displacement will increase rig time and costs considerably, especially for deepwater completions.[5 6]

Traditional displacement

Whether the displacement is direct, indirect, or balanced, the displacement process usually includes a series of chemical spacers followed by brine, drill water, or seawater. Selection of the displacement fluid directly affects fluid handling on surface and the fluid volumes that may have to be disposed of off-location.

WET-TREE WELL GEOMETRY

Fig. 2



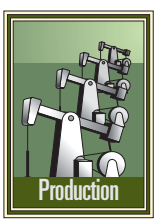
TD/TDV, ft 24,951 / 23,502
Water depth/air gap, ft 6,262/93

Annular volume, bbl	3,070.0		Film thickness, in.	0.047	
Work string volume, bbl	3,070.0		Work string film volume, bbl	10.3	
Total volume, bbl	3,592		Annular film volume, bbl	37.8	
Steel volume, bbl	171.1		Choke-line volume, bbl	75.5	
Hole volume, bbl	3,762.8		Kill-line volume, bbl	75.5	
			Boost-line volume, bbl	124.1	

Length, ft	Casing OD, In.	Casing ID, In.	Work string OD, In.	Work string ID, In.				
6,310	22.000	20.000	6.625	5.901				
45	13.000	11.000	6.625	5.901				
3,845	11.750	11.000	5,000	4.276				
11,352	9.625	8.157	5,000	4.276				
30	9.625	8.157	4.000	3.340				
3,369	7.000	6.004	4.000	3.340				

Length, ft		Annular volume, bbl	Work string volume, bbl	Steel volume, bbl	Annular capacity, bbl/ft	Work string capacity, bbl/ft	Steel capacity, bbl	Hole capacity, bbl
6,310		2,182.9	213.4	55.6	0.345937	0.033827	0.008810	0.388574
45		3.4	1.5	0.4	0.074907	0.033827	0.008810	0.117544
3,845		358.6	68.3	25.1	0.093258	0.017762	0.006524	0.117544
11,352		458.1	201.6	74.1	0.040350	0.017762	0.006524	0.064636
30		1.5	0.3	0.1	0.049093	0.010837	0.004706	0.064636
3,369		65.6	36.5	15.9	0.019475	0.010837	0.004706	0.035018

Selection decisions will consider the required pit space volume on the rig, cheap water source availability, wellbore ability to withstand the pressure differential between the water and drilling mud columns, and pump pressures required for the displacement.



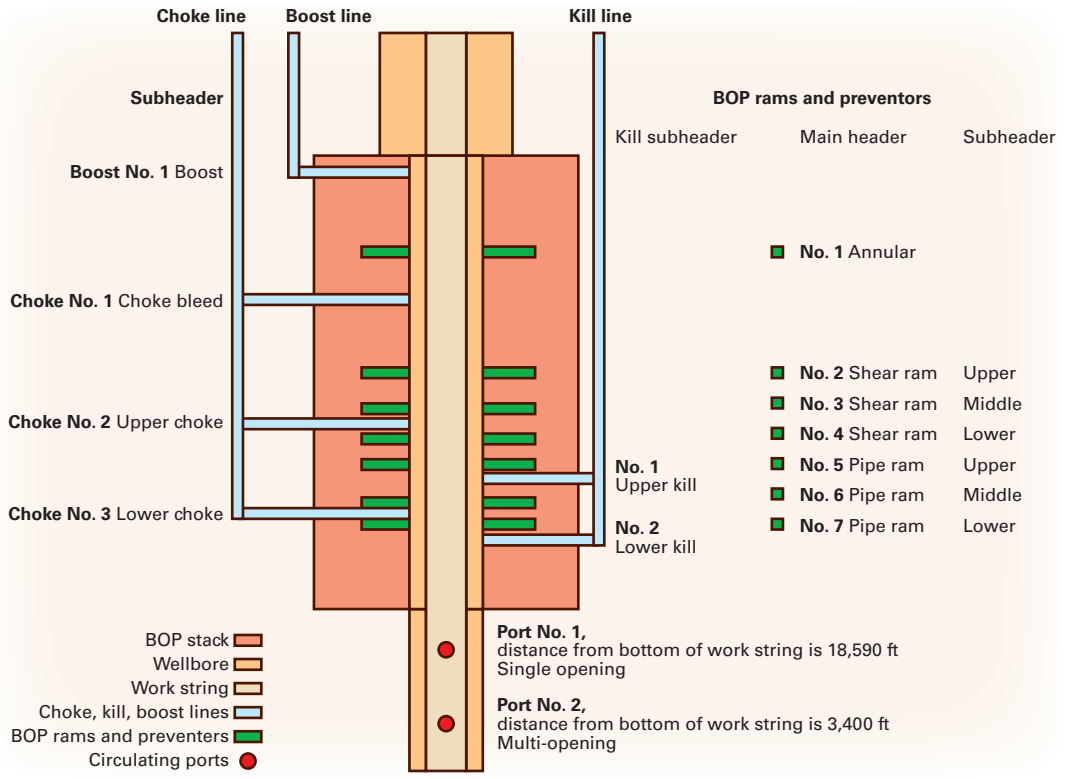
The direct method displaces the drilling fluid with cleaning spacers followed by completion fluid. This method is preferable in zero discharge areas where minimizing fluid waste is critical or when handling brine and mud on the surface at the same time is possible.

Direct displacement requires the availability on surface of a brine volume equal to the entire hole volume and the rig capacity to handle the displaced mud. Logistics are critical to the success of direct displacement. Technical capability and chemical availability have made the method suitable for most displacement applications that have manageable mud and brine handling means.

The indirect method displaces mud with cleaning spacers followed by a

BLOWOUT PREVENTER CONFIGURATION

Fig. 3



hole-volume of water. Completion fluid later displaces the water from the hole.

Some operators prefer indirect displacement because it allows for repeated flushing of the casing until clean with inexpensive seawater or drill water, which does not require filtering and usually can be discharged.

Unacceptable differential or pump pressure, however, may not permit filling the hole with seawater or drill water. Furthermore, exposing a liner top, open perforations, or openhole to the negative differential of seawater or drill water relative to a mud column may not be prudent. Consequently, these cases require a balanced or near-balanced method.

The balanced method essentially is another type of direct displacement. In this case, weighted spacers balance the mud column, thereby minimizing the differential pressures during the pumping of the displacement fluid.

For example, low-density spacers in seawater may require pump pressure during circulation that exceeds the formation fracture pressure or the pressure that an exposed liner top will tolerate before breaking down. Moreover, these spacers may apply insufficient hydrostatic pressure to hold back the formation during the displacement.

Weighted spacers to a balanced or near-balanced condition until the total hydrostatic pressure equals or nearly equals the formation or liner-top pressure reduces the pump pressure required to move the spacers around the hole. In addition, balanced or near-balanced weighted spacers will facilitate well control by maintaining constant pressure on the reservoir.

Spacer systems differ depending on whether the displacement involves oil-based mud (OBM), synthetic-based (SBM), or water-based mud (WBM). Displacements of OBM and SBM use solvent and surfactant chemistry as the primary cleaning agents, while WBM displacements use caustic solutions and water-wetting surfactants.

In either case, the spacers are designed for a specific function, such as:

- Physically move or dislodge the drilling mud.
- Clean the mud film from the tubulars and casing, leaving them water-wet.

The spacer must be compatible with the drilling mud being displaced. With the exception of openhole displacements, where it may be desirable to leave the mud filter cake intact, the spacers should remove all trace of the mud from the wellbore.

Tables 1 and 2 list the function and qualities of typical spacers used in a direct or indirect displacement.

Deepwater demands

Deepwater completions are either dry or wet tree (subsea), with the dry-tree completions usually conducted from a moored tension-leg platform (TLP) or spar-type platform. Dry-tree completions have production-sized casing run from the platform to the seafloor (Fig. 1).

Subsea completions involve large (about 20-in. ID) riser pipe that runs from the mud line to the offshore vessel from which operations are conducted (Fig. 2). This large riser pipe and the auxiliary lines that attach to the blowout preventers (BOPs) complicate the displacement process for subsea-completed wells.

Regardless of completion type, the low mud-line temperature in deepwater affects significantly both fluid selection

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TYPICAL SPACERS

Table 1

	Spacer type	Function	Qualities
Oil or synthetic-based	Base oil	Thin mud	
	Transition	Displace mud	More viscous and dense than, compatible with a drilling mud
	Cleaning	Clean pipe, water wet	Must be able to clean pipe at given contact time and rate
	Viscous tail	Separate spacers from brine	Made up with xanthan if possible
Water-based	Viscous lead	Displace mud	More viscous and dense than drilling mud
	Caustic	Breakdown remaining mud	May be split into segments separated by seawater pads
	Surfactant	Clean pipe, water wet	Freshwater if possible, low surfactant concentration
	Viscous tail	Separate spacers from brine	Made up with xanthan if possible

DISPLACEMENTS

Table 2

	Direct	Indirect	Balanced
Displacing fluid	Brine	Seawater/lease water	Brine
Spacers	Normal	Normal	Weighted
Active and reserve pit volume	Large	Minimal	Large
Zero discharge	Yes	No	Yes
Open hole	Yes	No	Yes
Exposed liner top	Yes	No	Yes
Pump pressure limitations	Yes	No	Yes
Open perforations	Yes	Possibly	Yes

In indirect displacment, lease water or seawater may be staged in the hole to displace a heavy water-based drilling fluid. A staged displacement displaces a portion of the hole volume at a time, leaving the remaining drilling fluid for a later stage or stages. This technique is not practical with oil-based or synthetic-based drilling fluids. Open perforations may be amenable to an indirect displacement if the exposed reservoir pore pressure is reduced to that of the water used.

and spacer chemistry performance. The job design, therefore, must consider how a wide temperature range that may vary by 200° F. affects both spacer size and cleaning efficiency.

In deep water, the drilling riser may have three and four times the capacity of the casing below the mud line. To attain minimum contact time, the riser annulus must have larger spacers than the same spacers used for cleaning the casing. Also, the riser spacers need much higher pump rates to achieve turbulent flow.

Cleaning the riser as well as the production casing, the choke and kill lines, the boost line, bleed-off lines, and the subsea BOP stack requires special attention (Fig. 3). The procedure should include fresh spacers to clean drilling mud and residual solids from the choke, kill, and boost lines. Failure to use fresh spacers risks circulating dirty or black water or whole mud into the surface system and filtration equipment.

The volume of viscous weighted transition spacer should equal 10% of the volume being displaced from the drill pipe and casing annulus, drill pipe and riser annulus, and other areas. The displacement design can base the size of the cleaning or wash spacer on the results from cleaning efficiency test described as follows.

To optimize the cleaning process, the subsea deepwater displacement should have three stages: casing and liner, riser, and auxiliary (choke, kill, and boost) lines.

Because it is always desirable to have pipe rotation during the displacement, pipe rams and annular preventers should remain open while the casing and liner are being displaced. This requires that the riser annulus accommodates the returns.

Once the spacers and displacing fluid have entered the riser, the next stage displaces the fluids in the riser with fluids pumped down the drill pipe and auxiliary lines. The last stage cleans the auxiliary lines, with rams and preventers closed.

True crystallization temperature (TCT) is rarely a problem under the dynamic conditions of a mud-to-brine displacement. The design should base its selection of the displacement fluids, however, including the completion brine, on the fluid's ability to keep salts in solution below the lowest temperature in the well at the mud line. Because pressure tends to increase the TCT of some salt brines, the design must consider pressure crystallization (PCT) effects.

Deepwater applications often include completion brines with a TCT of 11-15° F. lower than usual for a given temperature to compensate for pressure effects, such as that seen during a BOP test.[7]

Subsea openhole completions

Openhole completions are common in shallow-water (less than 1,000 ft) and recently have become more common in the deep water.

These completions require balanced fluid weight with reservoir pressure so that fluids will not enter the well because of underbalance or break down the formation because of overbalance.

A very narrow window between reservoir pore pressure and reservoir fracture pressure may exist in shallow gas openhole completions. Accordingly, the reservoir drill-in (RDF) and completion fluids must work within those limits.

Prior to drilling the pay sand, the drilling operation may use an RDF to displace the drilling mud after drilling out of the casing shoe. In this instance, an RDF will be used to drill the openhole section. This is followed usually by displacing the RDF from the openhole with a solid-free version of a base fluid identical to RDF. This guarantees compatibility with the formation and is intended to maintain the filter cake integrity and minimize fluid losses.

The operation must maintain compatibility between the drilling mud and RDF, the mud and completion brine, and the RDF and completion brine. Fluids circulated into the openhole also must be compatible with fluids already in place, formation fluids, and forma-

The cleaning spacer design test includes a preweighed capped carbon steel sleeve mounted on the spindle of a Fann 35 rheometer. The test's first step is to immerse the sleeve in drilling mud for 15 min at 3 rpm to form a consistent coating (left photo above). The next step removes the sleeve from the mud and allows the sleeve to drip for 1 min, after which the bottom cap is wiped clean and the sleeve weighed. The next part of the test involves remounting the sleeve on the spindle and immersing it in the cleaning solution at set rpm (100, 200, or 300) for 1, 2, 4, 6, and 10 min. After each immersion, the sleeve is removed and weighed. The test is complete either when the spindle is clean or at 10-min contact time even if it is not clean. The upper right photo shows the sleeve after a 6-min immersion in cleaning spacer solution at 100 rpm. The lower right photo is the same sleeve after a 10-min immersion (Fig. 4).

tion mineralogy.

Laboratory tests should confirm that the displacing fluids will not emulsify or sludge with the mud or RDF in the openhole or with the formation water or crude. To prevent swelling or dispersion, the design should select an RDF and completion brine based on shale stability and clay inhibition.

Furthermore, the potential for the formation of gas hydrates is a critical consideration when engineering a subsea openhole displacement. Mixing methane or other hydrocarbon gas with water under low temperature and high pressure during extended shut-in periods can initiate the formation of gas hydrate.

In openhole displacements, this condition may arise if there is a shutdown during displacement or if there are trapped fluids in a dead area, such as an isolated riser, choke, or kill line. When the well has an acute potential for gas-hydrate formation, brine selection is crucial and the displacement fluid must contain sufficient salt or other hydrate inhibitor.

Openhole displacements usually have two stages: displacing the drilling mud or RDF out of the openhole, and displacing the drilling mud or RDF out of the casing. In most cases, a completion brine will follow the casing displacement spacers. This requires balanced fluid density, pressure maintenance below fracture gradient during displacement, spacers that will not erode the filter cake in the openhole, and compatibility of spacers and completion fluid with either the drilling mud or RDF and formation fluids.

For subsea openhole completions, the well fluids must maintain a balanced pressure on the reservoir throughout the displacement. The hydrostatic density of the fluid column both during displacement and the fluid left in the hole after displacement needs to be sufficient to control formation pressure and prevent fluid ingress into the openhole.

This usually will require a direct displacement of the production casing or weighted spacers that contain solids or are heavy clear brine fluids

For risers isolated for separate cleaning, the operation must make sure that the hydrostatic pressure remaining on the openhole is sufficient to prevent the reservoir from releasing formation liquids or gases. Failure to do so can create conditions favorable to hydrate formation or result in other well control problems.

Another preference is keeping an active riser annulus during displacement of the casing above the openhole. This allows rotating the drill pipe during the displacement.

Spacer chemistry

One should not assume that a cleaning additive blended in seawater, drill water, or brine will clean mud from tubulars and casing. Cleaning efficiencies change with mud type, base brine, additive concentration, pump rate, and contact time.

In deepwater, temperature plays a vital role. A spacer design may not be as effective at the deepwater mud line temperature of 40° F. as at the bottomhole temperature of 200° F. or warmer.

In most cases involving removal of oil or synthetic-based fluids, the cleaning spacer should consist of separate and consecutive stages, comprising a solvent in seawater or brine and a surfactant in seawater or brine. Dispersions of 10-20% solvent in seawater or

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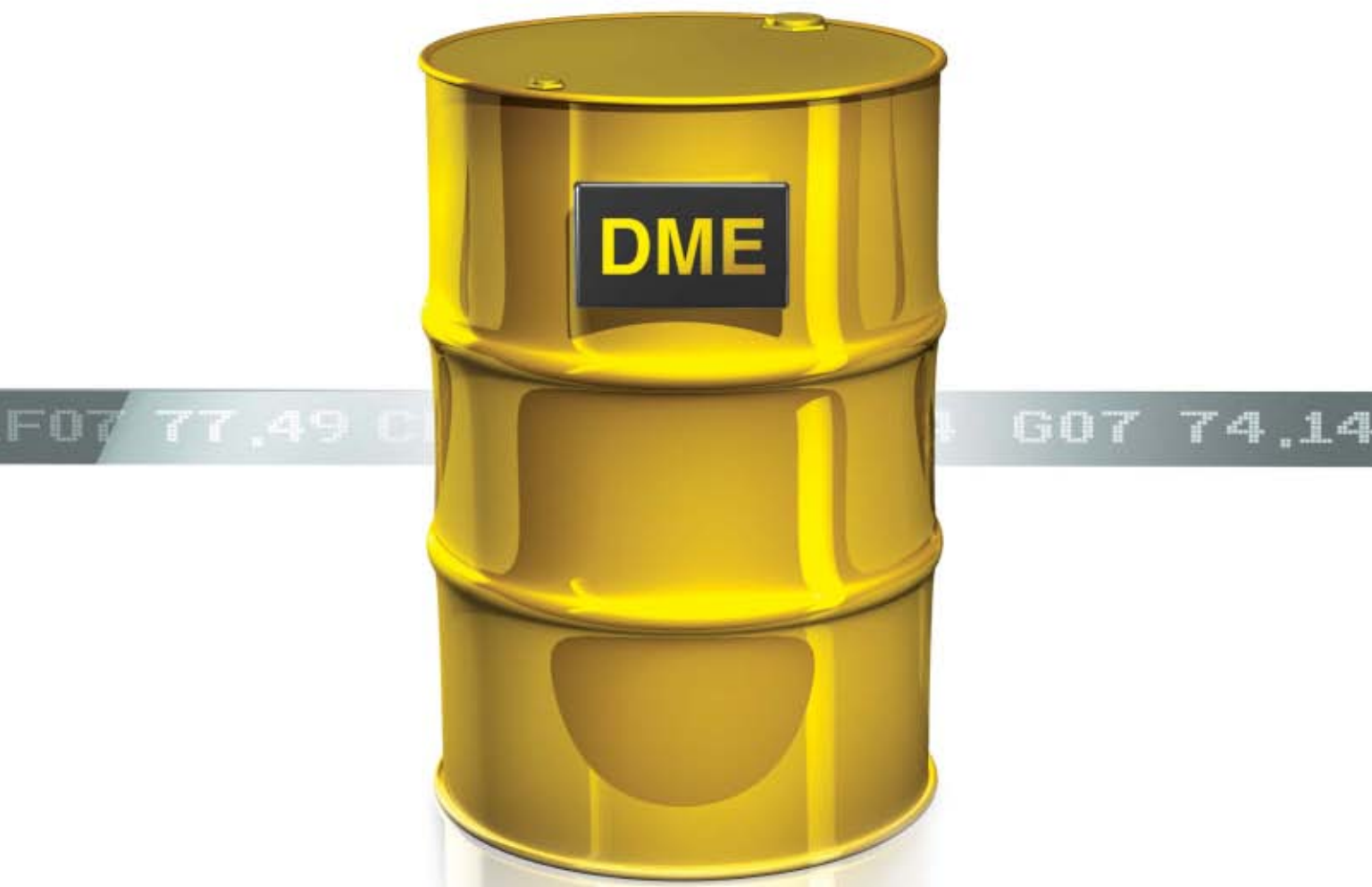

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brine are effective at removing mud solids and debris. A polishing solution of 3-10% surfactant is sufficient to remove oil-wet film and water-wet tubulars.

Fig. 4 displays laboratory tests that determine cleaning efficiency in OBM or SMB displacement spacers.

During direct displacements of high-weight mud, the cleaning spacer may require weighting to near mud weight, either to enable sufficient pump rate at acceptable pump pressure or lessen the negative differential pressure on a liner, perforations, or openhole. Because the cleaning spacer cannot include barite solids for weighting up, it has to use high-density brine.

The laboratory tests described previously have shown that surfactant-solvent combinations usually are more effective when blended in base brine containing free water rather than in salt-saturated solutions. On the other hand, it has also been noted that a surfactant added to saturated brine that has been cut back with water may increase viscosity when the spacer picks up drilling mud. This added viscosity acts to block further mud removal. Prior testing on the mud and surfactant or surfactant-solvent spacer can determine if the additive will have the desired effect.

The activity of spacer chemicals changes with temperature. The cleaning efficiency of solvents and surfactants may not be as great at 40° F. as at 150° F. Accordingly, the procedures should include testing the solvents, surfactants, and their blends against the mud and crude at lower temperatures to ensure cleaning efficiency in deepwater displacement applications.

Various tools provide a means for mechanically cleaning the casing. The top photo shows a casing brush-scraper combination. The middle photo is a closeup of a set of scrapers and two sets of brushes on one tool. The bottom photo shows a riser brush (Fig. 5).

Mechanical displacement aids

Typically, the cleanout string run to bottom prior to the displacement will include casing brushes and scrapers (Fig. 5). In holes deviated 30° or more from vertical, brushes and scrapers play an essential role in disturbing mud pockets that will form on the low-side of the casing. These tools can remove mechanically mud solids from the casing wall as a precursor to the chemical sweeps and washes that push the mud from the hole.

The usual string includes one scraper spaced out to land at the bottom of each string of casing or liner and one or several brushes spaced out in each size string, depending on the string length.

In a short-trip, the procedure involves pulling the pipe until the top brush is exposed at the surface; at that point, brushes spaced throughout the drillstring will have swept across each foot of casing as they come up the hole. The clean-up string run back to bottom completes the short-trip.

Often the job will also involve reciprocating the scrapers to remove cement or scale across intervals where packers will be set or perforations made.

In deepwater displacements, the procedure will incorporate riser brushes for sweeping the riser annulus and a jetting tool placed across the BOP stack for flushing mud, water, or brine at high flow rates into hard-to-access pockets of the stack body. The indirect method often includes jetting after the displacement to seawater.

Other mechanical aids used in the displacement string are bits and mills, junk baskets for carrying debris out of the hole, and magnets for capturing and transporting to surface large metal cuttings. ✦

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The authors

Syed Ali (syed@chevron.com) is a research consultant for Chevron Energy Technology Co., Houston. He specializes in sandstone acidizing, formation damage control, rock-fluid interaction, mineralogy, and oil field chemistry. Ali holds an MS from Ohio State University and a PhD from Rensselaer Polytechnic Institute, Troy, NY. He serves as an executive editor for SPE Production & Operations.

Michael T. Darring is Southern US Region technical service manager for completion fluids for M-I SWACO and is based in the New Orleans technical center. Darring has held operations and management positions in various fields of completion technology. Darring has a BA in philosophy from the University of Tennessee.

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CGES: Global crude supplies will continue to get heavier

According to a report from the Centre for Global Energy Studies (CGES), the global crude supply barrel got heavier during 2000-04. The July 5, 2006, report entitled "Global Oil Report: Market Watch—Trends in crude oil quality" said that increased amounts of heavier crudes would make their way to refiners in the coming years.

The crude supply barrel has changed substantially since 2000, according to a 2005 OPEC report.[1] That report concluded that there is currently a "mismatch between the installed refinery capacity and crude type." The CGES report examines in detail the changes that have occurred to the crude stream coming to market during the last 5 years.

Non-OPEC supply barrel

Medium and heavy crudes, which in 2000 accounted for 59% of non-OPEC oil supplies, made up 66% of the crude brought to the market by non-OPEC producers in 2004, according to the report (Fig. 1). The increase in heavy crude supplied to 17% from 15% of the total crude barrel is an increase of 23% in the actual volumes of heavy crude entering the market during 2000-04. In contrast, the volume of light crude produced by non-OPEC countries decreased 10%.

According to the report, the shift in crude gravity was due to:

- Growth in heavy, sour crude production that reflects increases in Canadian bitumen and output from Chad, Brazil, Ecuador, and Mexico.
- Growth of medium-API sour crude production that mainly reflects the increased output of Russian Urals (33° API with 1.3% sulfur).
- Other contributors to the growth in medium-API crude include Angola, Canada (syncrude), Equatorial Guinea, and Sudan, although all of this was actually low-sulfur crude.
- The net loss in light API, sweet crude is due to declines in OECD oil production mainly in the North Sea, Australia, Canada, and US, as well as in Colombia. The only two countries that showed a significant net increase in light crude production were Kazakhstan and Vietnam, but were predominantly sour crudes.

The report stated that the quality of non-OPEC crude has been falling since 2000. The average gravity of non-OPEC crude production slipped to less than 31.5° API in 2005 from around 33.2° API in 2000.

"New non-OPEC oil from countries like Russia, Kazakhstan, Equatorial Guinea, Sudan, Angola, and others has been inferior in quality to the oil lost from places like the North Sea, Australia, Canada, and the US," according to the report. "The picture is similar for North America, where the average quality of the crude oil produced has fallen from 28.4° API to 27.7° API between 2000 and 2005."

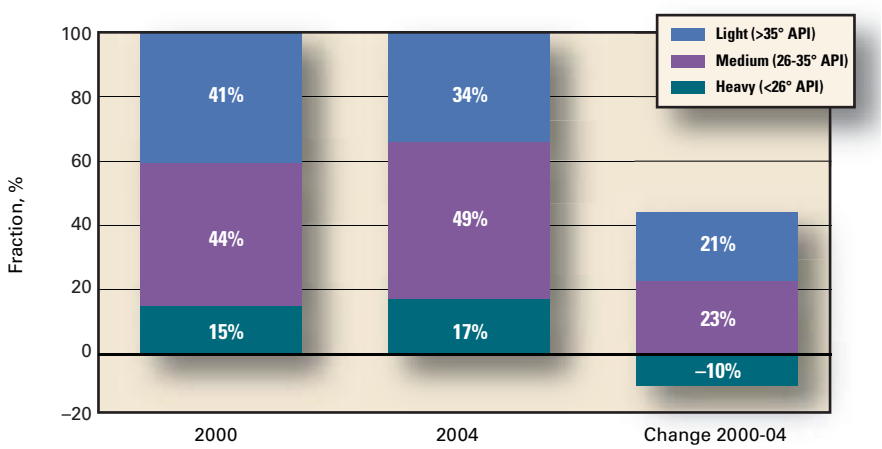
Although output of light West Texas Intermediate (WTI) has declined, incremental production has come from conventional sources in the Gulf of Mexico and from Canada's extra-heavy oil deposits, which are syncrude that has an API of between 31° and 33°, according to CGES.

OPEC supply barrel

During the 4-year period, the proportion of heavy crude produced by

NON-OPEC CRUDE SUPPLIES

Fig. 1



Sources: OPEC, BP PLC, CGES

OPEC member states dropped to 6% from 9%, while the share of light crude increased to 32% from 30% of supply in 2004 (Fig. 2).

In volume terms, OPEC's production of light crude increased by 0.9 million b/d and of medium gravity crude by 1 million b/d from 2000 to 2004, while production of heavy crude fell by close to 0.8 million b/d, according to the report.

The increase in OPEC's light oil production reflects rising output from Algeria and Libya. The decline in heavy oil production is due to a drop in output in Venezuela (Fig. 3).

CGES's analysis of OPEC's production figures indicates that these production patterns held through 2005.

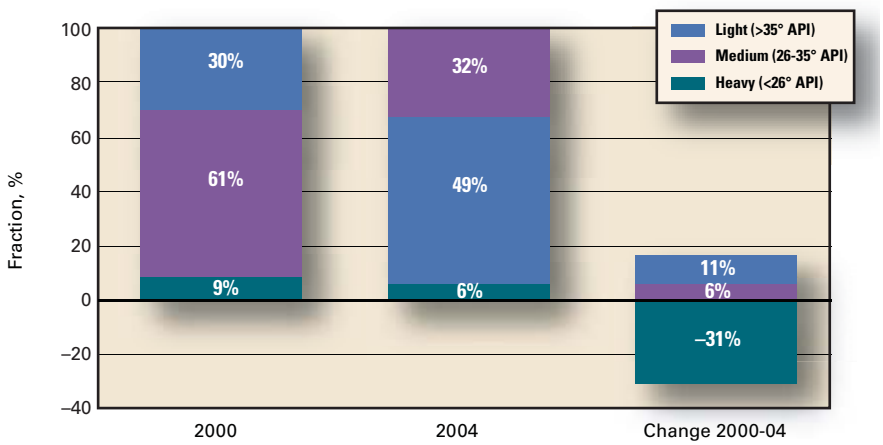
More recently, incremental OPEC output, which has averaged slightly more than 850,000 b/d/year during 2004-05, has been dominated by Saudi Arabia, which has boosted its oil production to around 9.5 million b/d. OPEC oil production in 2005 again consisted predominantly of light and medium grades, but the remaining spare production capacity, which is almost entirely concentrated in Saudi Arabia, is much heavier.

According to the report, until new capacity is brought on stream, which is taking place but relatively slowly, any incremental OPEC output will be predominantly heavy oil. The rise in the quality of OPEC supply is therefore insufficient to offset the declining quality of non-OPEC supplies.

Total OPEC and non-OPEC heavy-oil production for 2000-04 increased by 0.7 million b/d, output of medium grade crude increased nearly 5 million b/d, and the production of light crude declined 0.9 million b/d. This trend towards heavier crude oil production will continue in the short and medium term, according to CGES.

OPEC CRUDE SUPPLIES

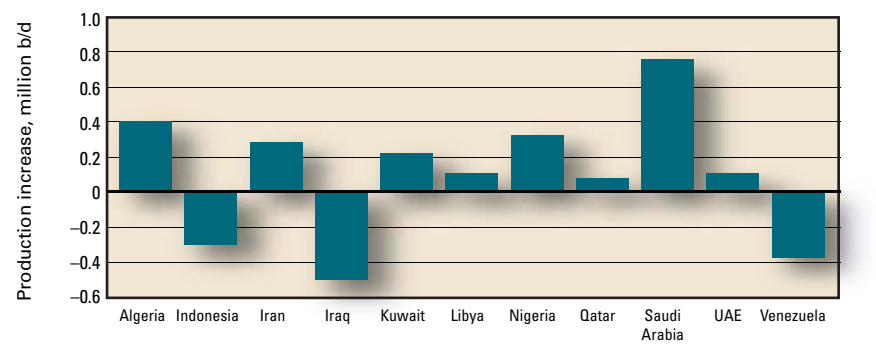
Fig. 2



Sources: OPEC, CGES

CHANGE IN OPEC PRODUCTION, 2000-04

Fig. 3



Source: CGES

Future supply barrel

Through yearend 2006, OPEC forecasts that light crude would account for 49% of the increase in its own oil production capacity, with medium grades making up 43% and heavy crude the remaining 8%. "This seems a positive step in view of what the market wants," according to the report. "But again it is important to take into account both the change occurring in the non-OPEC barrel over the same period and the relative amounts of oil brought to the market by the two groups of producers."

OPEC forecasts that light crude will account for just 16% of non-OPEC's capacity expansion 2005-06. Most of the growth, 62%, will come from medium crudes, while heavy oil will make up the remaining 22%, further changing the overall make-up of the non-OPEC supply barrel (Fig. 4). OPEC estimates its own crude oil capacity expansion 2005-06 at 2.1 million b/d, while predicting that non-OPEC oil production would increase 1.7 million b/d during the same time, a forecast that now looks overly optimistic.

The report states that—looking at the breakdown of OPEC's predicted oil-production capacity expansion by all producers over the short term—it is important to note that 65% of incremental production will come from medium and heavy crudes. In the medium term, medium crude will to continue to provide most of the non-OPEC production growth (Fig. 5), with the FSU (Russia, Kazakhstan, and Azerbaijan), West Africa (Angola, Equatorial Guinea, Chad, and Mauritania), Brazil, and Canadian syncrude all expected to contribute to non-OPEC output growth.

Offsetting some of these output increases is the decline in production of

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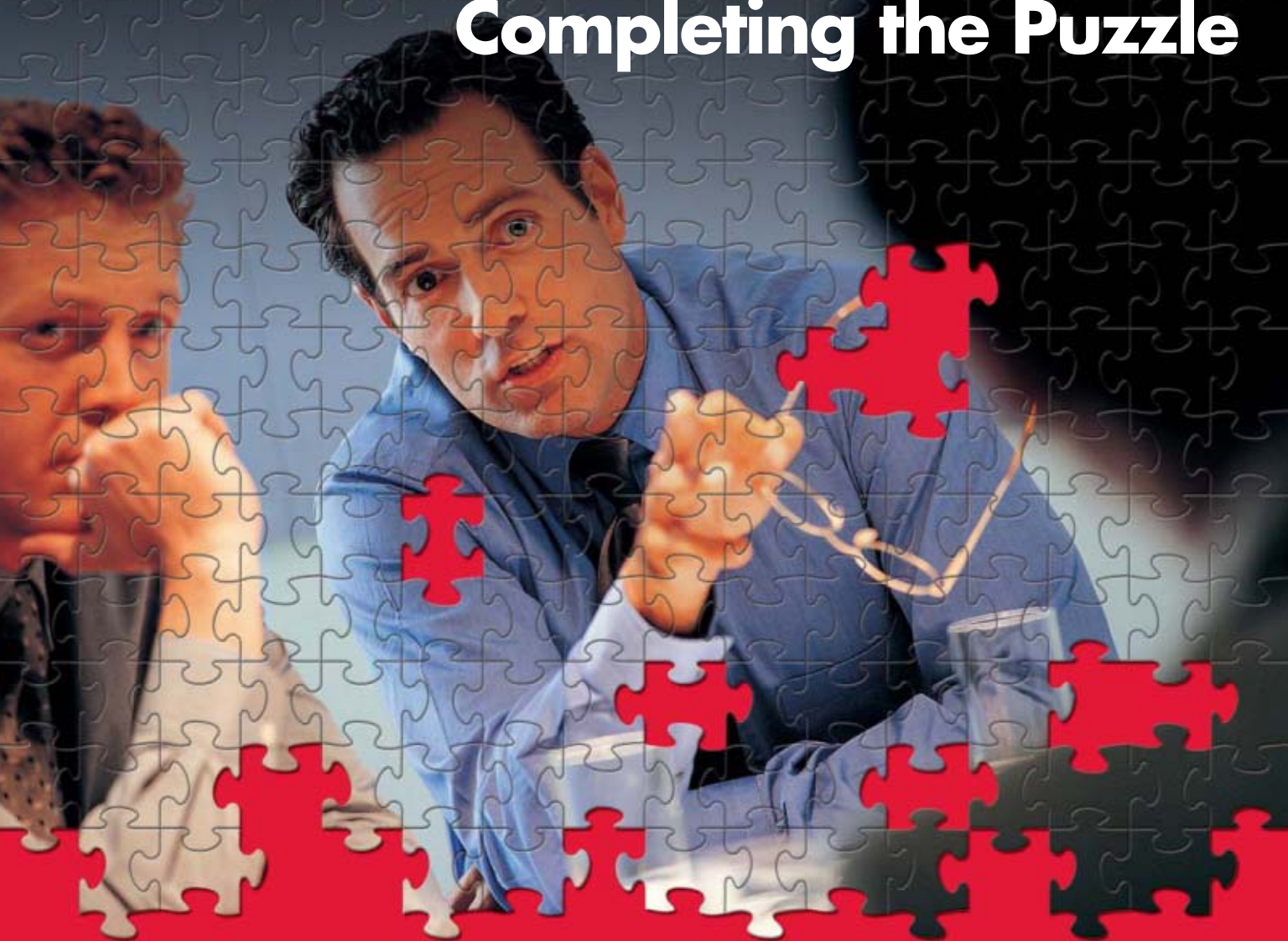

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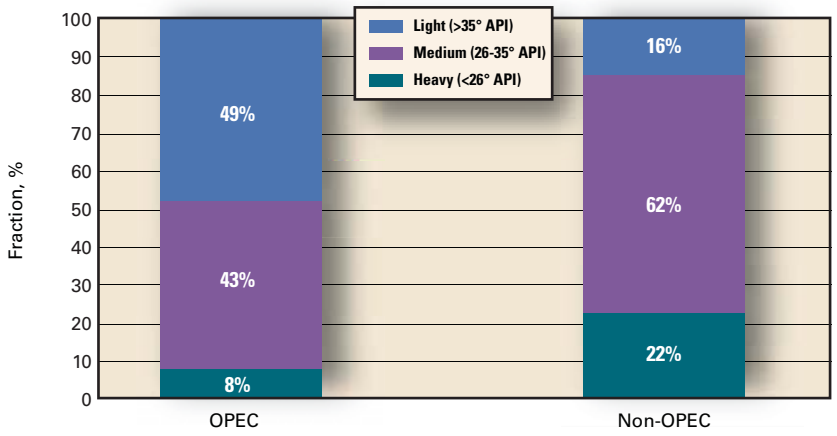
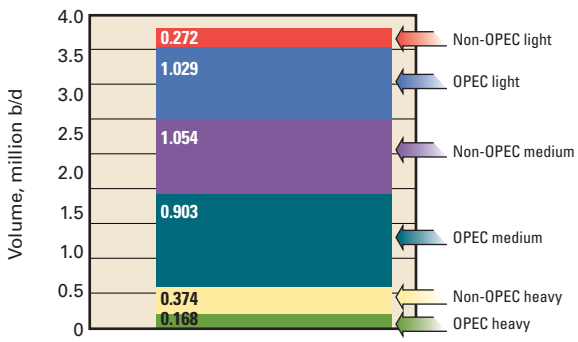
CRUDE SUPPLY EXPANSIONS, 2005-06

Fig. 4



2005-06 WORLDWIDE CRUDE SUPPLY EXPANSIONS

Fig. 5



Sources: OPEC, CGES

light, sweet crude from the North Sea and the Lower 48 states. North Sea oil production has been falling about 10%/year and the decline of this light, sweet crude will likely continue. OPEC's own medium-term production capacity expansion, however, will be overwhelmingly of medium and heavy, and predominantly sour, crudes. The most significant capacity expansion will come from the Middle East producers, led by Saudi Arabia.

Although Saudi Arabia is targeting lighter grades, additional oil from other regional producers, such as Kuwait and Iran, is likely to be significantly heavier, according to CGES. Iraq, however, will not add much to OPEC's oil production capacity during the next 2-3 years.

Any significant increase in the country's oil production will require foreign investment. This is unlikely to materialize on a large scale until the country is secure, the newly elected government is firmly established, a new hydrocarbons law has been adopted to manage the relationship between Iraq and foreign investors, and individual project negotiations have been completed. These necessary steps will likely take several years.

Despite these changes, it is clear that the overall weight of the global supply barrel will continue to increase over the coming years, whereas the world's demand barrel will continue to get lighter, according to the report. Refiners will, therefore, have to keep adjusting their upgrading capacity to be able to match the heavier supply barrel to the growing requirement for lighter products with less and less sulfur. ✦

Reference

1. "Evolving crude quality and implications for refineries," Monthly Oil Market Report, OPEC, August 2005.

PIPELINE FAILURE RATES—1

Method helps pool multisource data

Francisco Caleyo
Lester Alfonso
Juan Alcántara
José Manuel Hallen
ESIQIE-IPN
Mexico City

Francisco Fernández-Lagos
Hugo Chow
Pemex Exploración y Producción
Mexico City

The statistical uncertainty in the estimation of the average failure rate of a group of pipelines decreases as failures, km-years, or both increase. This fact has led to the tendency in pipeline reliability analyses to increase the number of km-years from which the failure data are pooled, reducing statistical uncertainty associated with estimating the failure rate.

This approach, however, is only valid if the uncertainty arising from the physical, environmental, and maintenance differences between pipeline systems is negligible.[1]

Oil and gas pipeline systems encompass many failure mechanisms, the most common being corrosion metal loss, third-party damage, geotechnical hazard, hydrogen-assisted and stress-corrosion cracking, and construction or material imperfections.[2] These failure mechanisms can lead to ultimate failure modes, such as rupture and leakage.

Tolerance uncertainty describes the statistical errors that arise from merging inhomogeneous pipeline failure datasets. Pipeline failure-rate estimation, however, has consistently ignored tolerance uncertainty. A reliability methodology that allows estimating the pipeline population-failure rate together with the statistical and tolerance uncertainties associated with the estimate would yield more accurate results. A key element of this methodology should be the ability to establish whether the pipeline systems are similar enough to allow pooling of failure data across systems.

This article proposes such a methodology. This methodology holds particular utility when, rather than relying on average values, the failure rate needs to be estimated accurately from data gathered for multiple pipeline systems showing significant physical, environmental, and maintenance differences. It allows for addressing failure processes with constant or varying intensity and testing whether the pipeline systems are similar enough so that pooling failure data across them can reduce the statistical uncertainty in the failure rate estimation.

Current pipeline reliability analyses tend to increase the number of km-years from which the failure data are gathered with the purpose of reducing statistical uncertainty. This might lead pipeline operators to establish improper maintenance priorities due to the large tolerance uncertainty associated with pooling failure data across dissimilar pipeline systems. This article intends to raise awareness of this problem and provide pipeline reliability analysts with the methods to address it properly.

Part 1, presented here, offers the new methodology for estimating failure rates of a pipeline population from historical failure data pooled across pipeline systems based on the statistical methods for the reliability of repairable systems. Pipelines are repairable systems since, upon failure, they can be restored to operation by some repair process other than total replacement.[3,4] Part 2 will outline and illustrate this methodology using real failure data compiled by the Office of Pipeline Data from oil and gas pipeline systems in southern Mexico and the US.

Basic definitions

This article treats pipelines as repairable systems. The term pipeline system refers to a group of pipelines that can be modeled by the same point stochastic process to describe the occurrence of failures in time. A pipeline system, therefore, is a repairable system with repairable subsystems (pipelines) that can all be described by the same process.

This allows assessment of tolerance uncertainty from system-to-system only when failure data are mixed to estimate a generic failure rate for the pipeline population. The totality of the pipeline systems used to carry out such estimation comprises a sample of the population under investigation. Fig. 1 illustrates some defining system variables

Based on presentation to the International Pipeline Conference, Calgary, Sept. 25-29, 2006.

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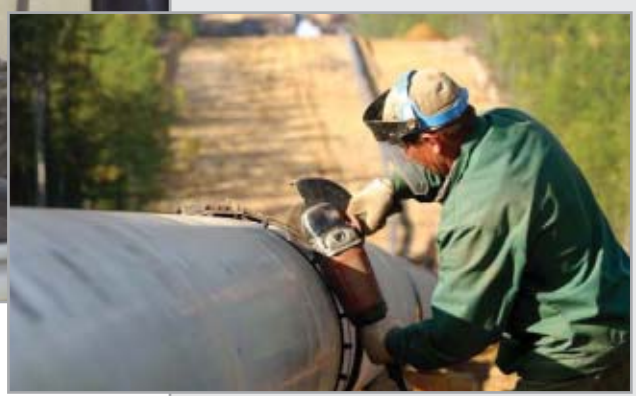

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EQUATIONS

$$\mu(t) = \frac{d}{dt}(E(N(t))) \quad (1)$$

Where:

$E(N(t))$ = the expectation of $N(t)$

$$\lambda(t) = \lim_{\Delta t \to 0} \frac{P(N(t, t+\Delta t] \geq 1}{\Delta t} \quad (2)$$

$$\bar{\bar{\lambda}}_{np} = \frac{N(T_{exp})}{L_{exp}\, T_{exp}} \quad (3)$$

$$\bar{\bar{\lambda}}_{np}(T_i) = \frac{N(T_i - 1) - N(T_i)}{L_{exp}} \quad (4)$$

Where:

$T_i \geq 1$ year refers to year i and the observation subinterval has been taken as 1 year to produce annualized failure rates. The units of both estimates are 1/km–year.

$$\bar{\bar{\lambda}}_{p} = \frac{\sum_{i=1}^{n_d} n_i}{\sum_{i=1}^{n_d} l_i t_i} \quad (5)$$

Where:

n_i = the number of failures in the i–th pipeline with length l_i (km) over observation time t_i (years).

$$N(T_{exp}) = \sum_{i=1}^{n_d} n_i \text{ and } L_{exp} = \sum_{i=1}^{n_d} l_i \quad (6)$$

$$\frac{\chi^2_{1-\alpha/2}(2N(T_{exp}))}{2L_{exp}\, T_{exp}} < \lambda < \frac{\chi^2_{\alpha/2}(2N(T_{exp}))}{2L_{exp}\, T_{exp}} w \quad (7)$$

Where:

$\chi^2_v(n)$ = the value of the chi–square with n degrees of freedom distribution that produces a probability v.

$$N(t) = (t/\theta)^{\beta} \quad (8a)$$

$$\lambda(t) = \left(\frac{\beta}{\theta}\right) \times \left(\frac{t}{\theta}\right)^{\beta - 1} \quad (8b)$$

Where:

θ and β = the scale and shape parameter respectively.

$$\hat{\beta} = \frac{N(T_{exp})}{N(T_{exp}) \ln(T_{exp}) - \sum_{i=1}^{N(T_{exp})} \ln(t)} \quad (9)$$

Where:

t_i = the time of the i–th failure

$N(T_{exp})$ = the total number of failures occurring in all pipelines in exposition time, T_{exp}.

$$\hat{\theta} = T_{exp} N(T_{exp})^{-1/\hat{\beta}} \quad (10)$$

$$\hat{\theta}(t) = \frac{\hat{\beta}}{L_{exp} \hat{\theta}^{\hat{\beta}}} t^{\hat{\beta} - 1} \quad (11)$$

$$\frac{\chi^2_{1-\alpha/2}(2N(T_{exp}))\hat{\beta}}{2N(T_{exp})} < \beta < \frac{\chi^2_{\alpha/2}(2N(T_{exp}))\hat{\beta}}{2N(T_{exp})} \quad (12)$$

$$\rho_1 \hat{\lambda}(t) < \lambda(t) < \rho_2 \hat{\lambda}(t) \quad (13)$$

$$\chi^2_{\alpha/2}(2N(T_{exp})) < \frac{2N(T_{exp})}{\hat{\beta}}$$

or

$$\frac{2N(T_{exp})}{\hat{\beta}} < \chi^2_{1-\alpha/2}(N(T_{exp})) \quad (14)$$

$$F = \frac{\hat{\bar{\lambda}}_1}{\hat{\bar{\lambda}}_2} \asymp F(2N_1, 2N_2) \quad (15)$$

Where:

N_1 and N_2 = the total number of failures in systems 1 and 2, respectively, during the observation period.

$$LR = -2N_T(T_{exp}) \ln\left[\frac{N_T(T_{exp})}{(T_{exp})\, L^T_{exp}}\right] + 2\sum_{i=1}^{k} N_i(T_{exp}) \ln\hat{\lambda} \quad (16)$$

Where:

$N_i(T_{exp})$ and $N_T(T_{exp})$ = the number of failures in the i–th system and in all systems over the observation period T_{exp}, respectively.

L^T_{exo} = the total length of these systems.

$$LRM = \frac{LR}{1 + \left[\sum_{i=1}^{k} N_i(T_{exp})^{-1} - N_T(T_{exp})^{-1}\right](6(k-1))^{-1}} \quad (17)$$

$$F = \frac{\hat{\beta}_2}{\hat{\beta}_1} \approx F(2N_1, 2N_2) \quad (18)$$

Where:

N_1 and N_2 = the total number of failures in systems 1 and 2, respectively, over observation period.

$$\hat{P} = 2P(n_1 \geq N_i(T_{exp}) \mid N_T(T_{exp}), S) = 2(1 - P(n_1 < N_i(T_{exp}), S))$$

$$P(n_1 < N_i(T_{exp}) \mid N_T(T_{exp}), S = \frac{1}{c}\sum_{n=0}^{n_1} \left\{ Bin(N_T(T_{exp}), n) \left[\frac{n1n(L^1_{exp} \mid L^2_{exp}) + }{N_T(T_{exp})\, 1n(T_{exp}\, L^2_{exp}) - S} \right]^{N_T(T_{exp})-1} \right\} \quad (19)$$

with:

$$c = \sum_{n=0}^{N_T(T_{exp})} \left\{ Bin(N_T(T_{exp}), n) \left[\frac{n\ln(L^1_{exp} \mid L^2_{exp}) + }{N_T(T_{exp}) \ln(T_{exp}\, L^2_{exp}) - S} \right]^{N_T(T_{exp})-1} \right\}$$

$$S = \sum_{i=1}^{N_T(T_{exp})} \ln(t_i - 0.5)$$

Where:

$Bin(\cdot, \cdot)$ = the binomial coefficient.

$$LRK = \frac{2\sum_{i=1}^{k} N_i(T_{exp}) \ln\hat{\beta}_i - 2N_T(T_{exp}) \ln\beta^*}{1 + \left[\sum_{i=1}^{k} N_i(T_{exp})^{-1} N_T(T_{exp})^{-1}\right](6(k-1))^{-1}} \quad (20)$$

$$\beta^* = \frac{N_T(T_{exp})}{\sum_{i=1}^{k} N_i(T_{exp})\, \hat{\beta}^{-1}} \quad (21)$$

$$\hat{d} = \sum_{i=1}^{k} (N_i(T_{exp}) - \bar{N}(T_{exp}))^2 / \bar{N}(T_{exp}) \quad (22)$$

Where:

$$\bar{N}(T_{exp}) = \frac{1}{k}\sum_{i=1}^{k} N_i(T_{exp})$$

for the US pipeline population.

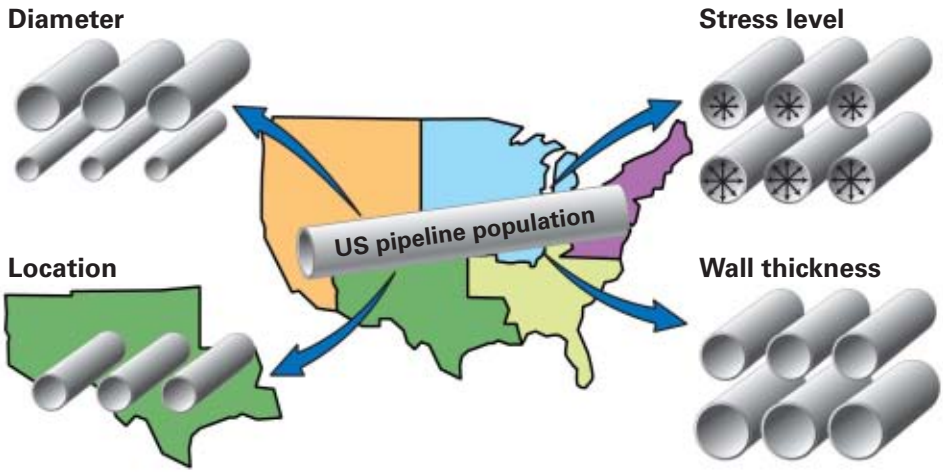
Equations 1 and 2 (see accompanying equation box) let $N(t)$ be a random variable that defines the number of failures in the interval $[0, t]$ in a pipeline system. The system rate of occurrence of failures at time (ROCOF), $\mu(t)$, and intensity function, $\lambda(t)$, are shown by Equations 1 and 2, respectively.

This paper uses the term failure rate in the ROCOF sense, provided that the ROCOF and the intensity function are considered equal and that both are measures of the reliability of repairable systems. The time subinterval, Δt, is taken as 1 year; referring to the annualized failure rate of the pipeline system.

Mechanisms that do not depend on time and show a constant failure rate can be modeled with a homogeneous Poisson process (HPP) with constant intensity λ. Cases in which the system deteriorates or improves its reliability with time should use the non-homogeneous Poisson process (NHPP). Fig. 2 shows the trend of $N(t)$ over service time for these reliability conditions.

DEFINING PIPELINE SYSTEMS

Fig. 1



Nonparametric estimate

Assume that a pipeline system has a total number of $T_{exp}L_{exp}$ km-years; T_{exp} and L_{exp} being the observation time interval (in years) and the total system length (in km), respectively. If the total number of failures is $N(T_{exp})$ over the observed interval (time truncated case), then Equation 3 expresses the nonparametric estimate of the system failure rate.

On the other hand, focusing on the time evolution of λ rather than its mean value over T_{exp} yields a simple nonparametric estimator of the system ROCOF (Equation 4).

Parametric estimate

If there are n_p pipelines in a system that can all be modeled by the same HPP, Equation 5 estimates the failure rate for the entire system.

In a time-truncated situation, when all pipelines have been observed over the same interval, $t^i = T_{exp}$, Equation 6 makes Equation 5 equal to Equation 3. It is important to note, however, that $\hat{\lambda}_{np}$ and $\hat{\lambda}_p$ represent two different ROCOFs. The first is an average value over a time interval of the system failure rate (which may not be constant), while the second is the estimate of an a priori assumed constant failure rate for a system that is believed to be the same at any point in time.

According to the HPP, the quantity $2\lambda T_{exp}$ has a chi-square distribution with $2N(T_{exp})$ degrees of freedom. Equation 7 provides a $100(1-\alpha)\%$ confidence interval for λ.

Equation 7 predicts that the statistical uncertainty associated with predicting λ under the HPP model decreases when the number of failures or the number of km-years, or both increase.

Power law

Equations 8a and 8b model the time evolution of the expected number of system failures and the ROCOF for the power law process.

The shape parameter β determines whether the system deteriorates ($\beta > 1$), improves ($\beta < 1$), or remains the same ($\beta = 1$) over time. Fig. 3 shows the failure intensity function for the systems considered in Fig. 2.

If there are n_p pipelines in a system which can be all modeled by the same power law process with parameters β and θ and all pipeline failure data are time truncated at the same time T_{exp}, Equation 9 shows the maximum likelihood estimate of β.

Equation 10 calculates the maximum likelihood estimate for parameter θ.

Equation 11 estimates the intensity function of the process in the pipeline system from the results of Equation 10.

The quantity $2N(T_{exp})\beta / \hat{\beta}$ has a chinsquare distribution with $2N(T_{exp})$ degrees of freedom, allowing Equation 12 to provide a $100(1-\alpha)\%$ confidence interval for β.

Equation 13 yields a $100(1-\alpha)\%$ confidence interval at time t regarding failure rate.[1]

Before computing the pipeline system's failure rate, it is important to check whether the system behaves, with respect to the evolution of the number of failures with time, as a homogeneous or a non-homogeneous Poisson process.

Truncated data require the statistic $2N(T_{exp})/\hat{\beta}$ be used to test for the HPP. The value of $\hat{\beta}$ is computed with Equation 9. The null hypothesis states that the process is an HPP, against the alternative that the true failure process is a power-law process. Either of the expressions in Equation 14 lead to rejection of the null hypothesis.

This test behaves optimally if the alternative is that the failure process is a power law process with intensity function given by Equations 8a and 8b.[3 4]

Pooling data

When failure data are available from more than one pipeline system, the pooling of these data across systems must occur with caution. Several tests can help determine if the systems are dissimilar enough that the process parameters for each system should be estimated independently or if they are similar enough that their failure data can be merged.

The HPP assumption commonly uses the Fisher (F) test to determine similarity between failure datasets prior to merging. If the failure data of two pipeline systems are to be aggregated and the systems are assumed to be modeled by an HPP with identical failure

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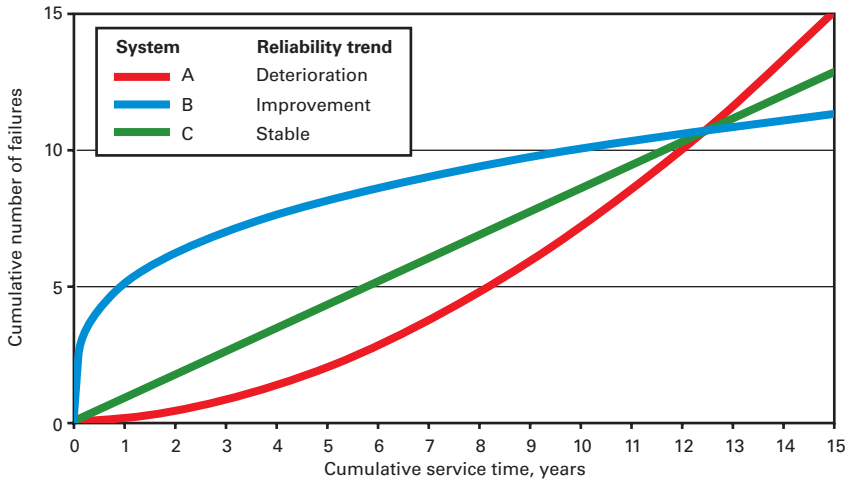
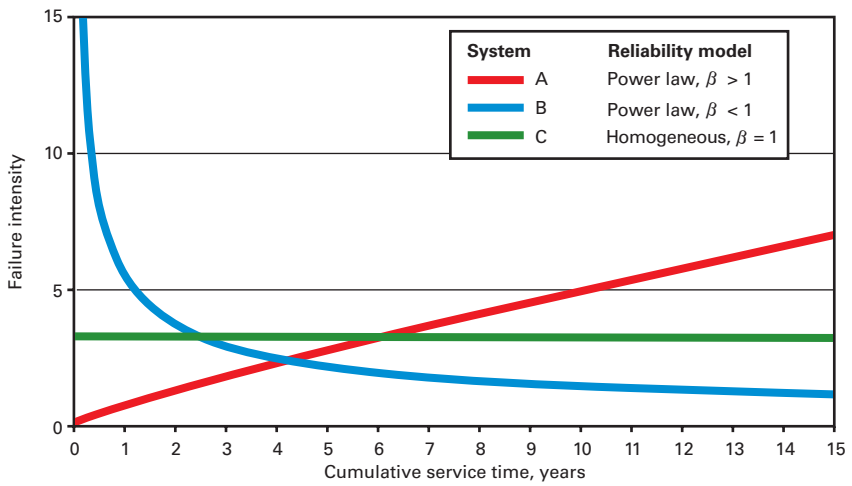
RELIABILITY TRENDS

Fig. 2



RELIABILITY MODELS

Fig. 3



rate, and the data are either failure or time-truncated, the null hypothesis that the λ's are equal (H_0: $\lambda_1 = \lambda_2$) can be tested against the two-sided alternative hypothesis H_a: $\lambda_1 \neq \lambda_2$.

Equation 15 holds when the null hypothesis is true.

Accordingly, rejection of the hypothesis that both systems have identical failure rates occurs at chosen significance level, α, if $F > F_{a/2}(2N_1, 2N_2)$ or $F < F_{1-\alpha/2}(2N_1, 2N_2)$.

The opposite situation, where there is no evidence to reject the null hypothesis, allows for pooling of the failure datasets of the two systems. In this case, Equation 3 estimates the failure rate associated with the mixed data sets, while Equation 7 provides the estimate's confidence bounds.

If the failure data of k pipeline systems need to be aggregated and the systems are assumed to be modeled by an HPP with identical failure rate, investigating whether the failure data from these systems can be mixed requires testing the null hypothesis H_0: $\lambda_1 = \lambda_2 = \lambda_3 = \ldots \lambda_k$ against the alternative that at least one of the λ is different.

For both the failure and time-truncated cases, distribution of the following statistics, based on a likelihood ratio (LR), takes a roughly χ^2 distribution with (k – 1) degrees of freedom (Equation 16).

The LR statistic provides a good approximation to the χ^2 distribution for moderate to large N_i (T_{exp}). For small values of N_i (T_{exp}), the modification of this statistic provided by Equation 17 might increase the accuracy of the χ^2 approximation.[3]

If the statistic LR (or LRM) is greater than the critical value χ^2_α (k –1) the null hypothesis that all systems have identical failure rates is rejected at the chosen significance level, α. In the opposite case, values of LR (or LRM) less than χ^2_α (k –1) allow aggregating the failure data of the k system into a generic database to estimate failure rates with reduced statistical uncertainty.

As in the two-system case, Equations 3 and 7 estimate the failure rate and the confidence bound of the estimate, respectively.

According to the power-law process assumption, merging failure data of two pipeline systems involves two steps. The first is testing whether the shape parameters (β's) estimated for both systems are identical and the second is testing if the failure rates of the systems are also identical.

The Fisher test compares the null hypothesis, H_0: $\beta_1 = \beta_2$, with the two-sided alternative hypothesis, H_a: $\beta_1 \neq \beta_2$. An accurate Equation 18 proves the null hypotheses true for the time-truncated case.

Either $F < F_{1-\alpha/2}(2N_1, 2N_2)$ or $F > F_{\alpha/2}(2N_1, 2N_2)$ leads to a rejection of thehypothesis that the β's estimated for both systems are identical.

The lack of a reason to reject the hypothesis that the estimated β's are identical provides the basis for investigating whether the failure rates for the two systems are similar: testing the null hypothesis, H_0: $\lambda_1 = \lambda_2$, against the alternative hypothesis H_a: $\lambda_1 > \lambda_2$. This process uses the approach proposed by Lee to test for equal failure rates (once the β's have been proved to be identical).[5]

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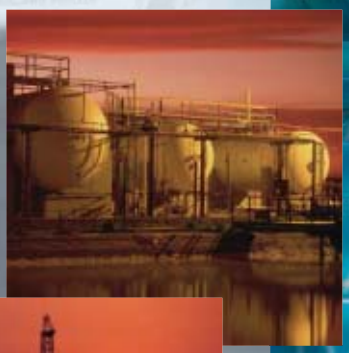

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This approach gives the system with the longer observation period the number 1.[5] The probability that the system experiences $N_1(T_{exp}) - 1$ failures or less determines the probability that system 1 experiences $N_1(T_{exp})$ or more failures over the observation period T_{exp}. The total number of failures in the two systems, N_T, and the sum of the logarithm of the failure times, S, condition these probabilities (Equation 19).[5]

Equation 19 says the larger the $\hat{P}$ value, the smaller the significant level with which the null hypothesis $H_0: \lambda_1 = \lambda_2$ can be rejected. If the hypothesis is not rejected, the intensity function of the two systems corresponds to the same power law, allowing the data gathered for both systems to be unified and modeled through a unique non-homogeneous Poisson process with a power-law intensity function.

The k pipelines case investigates the null hypothesis $H_0: \beta_1 = \beta_2 = \ldots = \beta_k$ against the alternative hypothesis that at least two of the coefficients are different.[3] Equation 20 provides a likelihood ratio statistic which can perform this investigation as a χ^2 distribution with $(k - 1)$ degrees of freedom.

Equation 9 calculates the estimates $\hat{\beta}_i$, where $N_T(T_{exp}) = \sum_{i=1}^{k} N_i(T_{exp})$ is the total number of failures for the k systems over the observation time and the coefficients β_i^* are the weighted harmonic mean of the $\hat{\beta}_i$ (Equation 21).

The chosen significance level α when $LRK > \chi^2_\alpha (k - 1)$ allows for the rejection of the hypothesis that the coefficients β_i are equal.

Rejecting the null hypothesis prohibits the failure data collected for the k systems from being merged. If there is no evidence to reject the null hypothesis, one can investigate if the failure rate λ_i of the k systems is similar. Testing the null hypothesis $H_0: \lambda_1 = \lambda_2 = \ldots = \lambda_k$ against the alternative hypothesis that at least two of the systems show different failure rates tests the equality of the λ_i. Equation 22 can perform this test.[5]

Equation 22 shows an χ^2 distribution with $(k - 1)$ degrees of freedom when the total number of failures in the k systems over the observation time is large $(N(T_{exp}) \geq 30)$. Once computed, the hypothesis that $\lambda_1 = \lambda_2 = \ldots = \lambda_k$ can be rejected at a significant level, α, when $\hat{d} > \chi^2_\alpha (k - 1)$.

Not rejecting the hypothesis that the β_i and λ_i's are similar for the k systems allows the failure data to be pooled across these systems to produce a generic failure rate with a reduced statistical uncertainty.

Acknowledgments

The authors thank Hugo Huescas for gathering the failure data used in this work. They are also grateful to Petróleos Mexicanos (Pemex) for permission to publish these results. ✦

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The authors

Francisco Caleyo (fcaleyo@gmail.com) is an associate professor at Instituto Politécnico Nacional de México (IPN). He heads a research team involved with the application of structural reliability analysis on onshore and offshore pipelines at the Centro de Investigación y Desarrollo de Integridad Mecánica (CIDIM) of the IPN. He holds a BSc in physics and an MSc in materials science from Universidad de La Habana and a PhD in materials science from Universidad Autónoma del Estado de México.

Lester Alfonso (lesterson@yahoo.com) is an assistant professor of Universidad Autónoma de la Ciudad de México. As a research professor at the CIDIM of the IPN, he develops numerical methods aimed at analyzing pipeline reliability and risk. He holds a BSc and an MSc in mathematical physics from Moscow State University and a PhD in atmospheric sciences from Universidad Nacional Autónoma de México.

Juan Alcántara is a member of the CIDIM of the IPN. He holds a BSc in physical metallurgy from IPN and is currently pursuing an MSc at the IPN in topics related to pipeline integrity and reliability analysis.

José Manuel Hallen (j_hallen@yahoo.com) is a full professor at the IPN and heads the CIDIM, which has service contracts with Pemex to conduct mechanical integrity and risk analyses of onshore and offshore pipelines. He holds a BSc and an MSc in physical metallurgy from IPN and a PhD in physical metallurgy from the University of Montreal.

Francisco Fernández-Lagos is a senior pipeline integrity specialist with more than 20-years' experience at Pemex. He currently works as pipeline integrity manager at the Gerencia de la Coordinación Técnica Operativa (GCTO) of Pemex. He holds a BSE in electrical control from Universidad Veracruzana and an MSc in pipeline management engineering from Universidad de las Americas.

Hugo Chow (hchowe@pep.pemex.com) is a senior pipeline integrity specialist with more than 20-years experience at Pemex. He currently works as pipeline integrity vice-manager at GCTO. He holds a BSE in electrical control from Instituto Tecnololgico de Ciudad Madero and an MSc in pipeline management engineering from Universidad de las Americas.

Equipment/Software/Literature

New fouling control technology aids refinery operations

New Milestone heater fouling control technology helps increase refinery profitability by significantly reducing delayed coker heater tube fouling rates.

The technology is a multicomponent fouling control solution designed to interrupt the key fouling mechanisms identified for specific coker heater operations and feedstock types.

Milestone technology programs can improve refinery profitability by:

- Increasing delayed coker unit throughput where throughput is limited by heater capacity.
- Allowing upstream crude units to process higher rates of lower-cost heavy crude oils.
- Reducing coil decoking costs.
- Reducing heater fuel consumption.

The firm says its fouling control approach has been proved effective in a joint Iindustry project pilot scale delayed coker testing program. Recent applications of MILESTONE technology in several commercial delayed cokers have significantly extended heater run lengths and increased unit throughputs, while reducing the frequency and cost of coil decoking procedures, the company says.

Source: **Baker Petrolite Div., Baker Hughes Inc.**, 12645 West Airport Blvd., Sugar Land, TX 77478.

New diode array process spectrophotometer

The new Model OMA-406 process analyzer fits in a standard 19 in. rack and is functionally identical to the company's OMA-300, which is typically housed in an explosionproof enclosure.

The analyzer contains no moving parts and is designed to address on-line applications that require fast, reliable, and maintenance-free monitoring of concentrations, including single and multicomponents.

Source: **Applied Analytics Inc.**, 2 Clock Tower Pl., Suite 535, Maynard, MA 01754.

New land wireline units available

A new generation of land wireline

units is on the market. The first one, built for use in Saudi Arabia's Damam oil field, is a double drum unit consisting of three compartments—winch, operator cabin, and workshop—mounted on a MAN 4x4 18GVW chassis.

The slick-line winch unit utilizes closed loop hydraulics, giving a combination of good acceleration and deceleration for jarring operations, and the ability to run smoothly at low constant speeds for memory logging applications.

Source: **AlMansoori Specialized Engineering**, Box 3374, Abu Dhabi, United Arab Emirates.

Services/Suppliers

Microsoft

Redmond, Wash., has announced the appointment of John Fikany as vice-president of the company's US manufacturing industries. Fikany is responsible for developing and leading strategy and execution for the entire US manufacturing operations. Microsoft's Houston-based Worldwide Oil and Gas Unit falls within this group, along with other vertical markets.

Microsoft, founded in 1975, is the leading provider of software, services, and solutions for individuals and businesses worldwide.

Fugro NV

Leidschendam, The Netherlands, has acquired Rovtech Ltd., Aberdeen, and will rename the company Fugro-Rovtech Ltd. and integrate its operations into Fugro Survey Ltd.'s facilities in Aberdeen. Jim Sommerville has been appointed managing director of Fugro-Rovtech, and Andrew Beveridge of Rovtech will take on the role of business development director. Phil Meaden is being promoted to Sommerville's former position as managing director of Fugro Survey Ltd.

Rovtech Ltd. provides remotely operated vehicle (ROV) services to the oil and gas industry, specializing in the inspection-repair-maintenance (IRM) and rig support sector.

Fugro Survey Ltd. is Fugro's European and Africa regional center of excellence for ROV construction support, international drill support, and subsea engineering services.

Fugro NV, founded in 1962, provides services in three areas: geotechnical, survey, and geoscience.

Petris Technology Inc. and Epis

Houston, have established a strategic alliance that will market Petris products and services in China.

Epis provides information solution products and services for oil and gas E&P decision making, integrating leading geoscience and IT technologies into its unique products and services. Epis has a strong customer network and service capabilities in China.

Petris Technology Inc. has expertise in data management, application hosting, and geospatial information systems.

Flowserve Corp.

Dallas, has announced the opening of a quick response center (QRC) in Moerdijk, Netherlands to provide mechanical seal manufacturing, repair, failure analysis, and inventory backup for Flowserve customers in the Netherlands and throughout northern Europe. Flowserve has opened or upgraded 16 QRCs around the world in the past 18 months.

Flowserve is a leading manufacturer of pumps, valves, seals and components to the process industries.

Assessing the Financial

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CONFERENCE MANAGEMENT CONTACTS

Conference Manager
Victoria Knowles
Tel: + 44 (0) 1992 656 653
Fax: + 44 (0) 1992 656 735
Email: iofconference@pennwell.com

Exhibit Sponsorship Sales Manager
Dawn Peek (in the US)
Tel: +1 713 963 6213
Fax: +1 713 963 6201
Email: iofsales@pennwell.com

Exhibit Sponsorship Sales Manager
Jonathan Franklin (in the UK)
Tel: +44 (0) 1992 656 658
Fax: +44 (0) 1992 656 700
Email: jfranklin@pennwell.com

Independent operators are playing a vital role in oil and gas exploration and production, and their increased participation in the international E&P arena has created information needs particular to that group.

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If you are involved in international exploration and production, you need to know the latest information on both these technical challenges and want to know about the financial opportunities. The Independent Operators Forum brings the best minds in the business together for two days of strategic information and real-life solutions. Make your plans now to be there.

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API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	9-15 2006	[1]9-8 2006	9-15 2006	[1]9-8 2006	9-15 2006	[1]9-8 2006	9-16 2005
	1,000 b/d						
Total motor gasoline	212	313	8	27	220	340	505
Mo. gas. blending comp.	406	620	30	54	436	674	218
Distillate[2]	344	438	85	124	429	562	132
Residual	399	363	62	16	461	379	492
Jet fuel-kerosine	116	79	107	122	223	201	115
LPG	430	418	1	1	431	419	243
Unfinished oils	466	418	83	48	549	466	531
Other	325	551	—	—	325	551	494
Total products	**2,698**	**3,200**	**376**	**392**	**3,074**	**3,592**	**2,730**
Canadian crude	1,793	1,391	375	202	2,168	1,593	1,715
Other foreign	7,953	8,343	1,200	1,158	9,153	9,501	6,966
Total crude	**9,746**	**9,734**	**1,575**	**1,360**	**11,321**	**11,094**	**8,681**
Total imports	**12,444**	**12,9034**	**1,951**	**1,752**	**14,395**	**14,686**	**11,411**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*9-15-06	*9-16-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	68.29	79.45	–11.17	–14.1
Brent crude	61.83	61.02	0.81	1.3
Crack spread	6.46	18.43	–11.98	–65.0
FUTURES MARKET PRICES				
One month				
Product value	69.97	78.65	–8.68	–11.0
Light sweet crude	63.98	63.86	0.12	0.2
Crack spread	5.99	14.79	–8.80	–59.5
Six month				
Product value	76.96	78.18	–1.22	–1.6
Light sweet crude	68.08	66.02	2.06	3.1
Crack spread	8.88	12.16	–3.27	–26.9

*Average for week ending
Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[2]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	14,933	56,938	27,341	10,155	65,688	18,168	9,392
PAD II	68,104	53,124	17,171	7,612	29,411	2,516	14,215
PAD III	171,522	68,069	29,148	12,189	36,779	16,650	47,163
PAD IV	12,892	5,713	1,632	623	3,185	522	2,594
PAD V	[1]53,759	29,842	20,006	9,527	12,504	5,791	21,075
Sept. 15, 2006	**[1]321,210**	**213,686**	**95,298**	**40,106**	**147,567**	**43,647**	**94,439**
Sept. 8, 2006[3]	**325,282**	**213,237**	**95,090**	**39,915**	**143,661**	**43,745**	**95,526**
Sept. 16, 2005	**305,076**	**200,563**	**71,176**	**38,952**	**133,056**	**33,048**	**86,364**

[1]Includes 4.840 million bbl of Alaskan crude in transit by water. [2]Included in total motor gasoline. [3]Revised.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

API REFINERY REPORT—SEPT. 15, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	2,694	1,510	1,523	1,618	94.1	1,771	87	430	115
App. Dist. 1	99	87	90	95	94.7	0	0	28	1
Dist. 1 total	**2,793**	**1,597**	**1,613**	**1,713**	**94.2**	**1,771**	**87**	**458**	**116**
Ind., Ill., Ky.	2,246	2,226	2,231	2,355	94.7	1,140	157	604	27
Minn., Wis., Dak.	365	354	355	442	80.3	254	34	104	7
Okla., Kan., Mo.	967	762	766	786	97.5	498	33	269	8
Dist. 2 total	**3,578**	**3,342**	**3,352**	**3,583**	**93.6**	**1,892**	**224**	**977**	**42**
Inland Texas	930	630	637	647	98.5	478	24	209	7
Texas Gulf Coast	4,067	3,503	3,633	4,031	90.1	1,352	335	988	131
La. Gulf Coast	3,278	3,229	3,262	3,264	99.9	1,341	347	969	127
N. La. and Ark.	224	195	196	215	91.2	103	13	36	4
New Mexico	170	93	111	113	98.2	110	2	37	0
Dist. 3 total	**8,669**	**7,650**	**7,839**	**8,270**	**94.8**	**3,384**	**721**	**2,239**	**269**
Dist. 4 total	**644**	**514**	**553**	**596**	**92.8**	**256**	**31**	**175**	**15**
Dist. 5 total	**2,936**	**2,635**	**2,829**	**3,173**	**89.2**	**1,720**	**384**	**565**	**158**
Sept. 15, 2006	**18,620**	**15,738**	**16,186**	**17,335**	**93.4**	**9,023**	**1,447**	**4,414**	**600**
Sept. 8, 2006*	**16,692**	**16,060**	**16,485**	**17,335**	**95.1**	**9,055**	**1,466**	**4,541**	**657**
Sept. 16, 2005	**17,333**	**15,001**	**15,466**	**17,115**	**90.4**	**8,707**	**1,603**	**3,884**	**649**

*Revised.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

Statistics

OGJ GASOLINE PRICES

	Price ex tax 9-13-06	Pump price* 9-13-06	Pump price 9-14-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	214.6	258.1	284.8
Baltimore	224.9	266.8	284.6
Boston	225.9	267.8	309.1
Buffalo	212.9	280.8	304.3
Miami	228.2	278.5	298.5
Newark	235.4	268.3	304.5
New York	217.6	285.5	310.3
Norfolk	207.8	245.8	294.1
Philadelphia	226.8	277.5	321.3
Pittsburgh	217.6	268.3	285.1
Wash., DC	243.2	281.6	308.9
PAD I avg.	223.2	270.8	300.5
Chicago	245.6	300.7	308.0
Cleveland	190.2	236.6	283.8
Des Moines	186.4	226.5	263.0
Detroit	194.9	247.8	272.2
Indianapolis	188.7	237.7	278.9
Kansas City	198.7	234.7	269.4
Louisville	194.5	231.4	274.9
Memphis	209.1	248.9	280.2
Milwaukee	216.4	267.7	287.9
Minn.-St. Paul	204.3	244.7	267.6
Oklahoma City	196.8	232.2	266.6
Omaha	187.9	233.3	281.2
St. Louis	203.3	239.3	279.8
Tulsa	203.2	238.6	265.6
Wichita	193.6	237.0	274.9
PAD II avg.	200.9	243.8	276.9
Albuquerque	224.7	261.1	288.4
Birmingham	201.4	240.1	287.8
Dallas-Fort Worth	198.5	236.9	283.8
Houston	201.2	239.6	285.8
Little Rock	202.5	242.7	279.6
New Orleans	226.3	264.7	NA
San Antonio	214.1	252.5	274.1
PAD III avg.	209.8	248.2	283.2
Cheyenne	246.5	278.9	286.9
Denver	245.6	286.0	297.9
Salt Lake City	247.5	290.4	288.6
PAD IV avg.	246.5	285.1	291.1
Los Angeles	228.1	288.7	305.9
Phoenix	218.8	256.2	301.4
Portland	242.7	286.0	283.7
San Diego	231.5	292.1	309.2
San Francisco	244.9	305.5	309.0
Seattle	244.9	294.3	293.2
PAD V avg.	235.1	287.1	300.4
Week's avg.	**216.4**	**260.8**	**281.8**
Aug. avg.	**252.4**	**296.7**	**250.2**
July avg.	**250.8**	**295.2**	**223.0**
2006 to date	**223.5**	**267.0**	—
2005 to date	**174.7**	**216.7**	—

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

REFINED PRODUCT PRICES

	9-8-06 ¢/gal		9-8-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	162.48	New York Harbor	175.35
Gulf Coast	161.10	Gulf Coast	179.60
Los Angeles	174.00	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	159.77	ARA	188.33
Singapore	160.12	Singapore	194.36
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	164.75	New York Harbor	102.98
Gulf Coast	161.75	Gulf Coast	113.76
Los Angeles	181.00	Los Angeles	120.61
		ARA	109.30
		Singapore	110.06

Source: DOE Weekly Petroleum Status Report.
Data available in Oil & Gas Journal Energy Database.

BAKER HUGHES RIG COUNT

	9-15-06	9-16-05
Alabama	4	4
Alaska	5	6
Arkansas	28	12
California	29	27
Land	25	23
Offshore	4	4
Colorado	94	79
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	10	8
Kentucky	9	7
Louisiana	202	185
N. Land	57	53
S. Inland waters	19	20
S. Land	45	37
Offshore	81	75
Maryland	0	0
Michigan	2	3
Mississippi	14	10
Montana	17	22
Nebraska	0	0
New Mexico	96	89
New York	7	5
North Dakota	38	28
Ohio	9	9
Oklahoma	193	154
Pennsylvania	14	15
South Dakota	3	4
Texas	780	627
Offshore	9	9
Inland waters	2	1
Dist. 1	23	12
Dist. 2	26	40
Dist. 3	58	98
Dist. 4	94	65
Dist. 5	141	81
Dist. 6	111	85
Dist. 7B	44	11
Dist. 7C	37	38
Dist. 8	94	75
Dist. 8A	26	22
Dist. 9	37	26
Dist. 10	78	64
Utah	44	27
West Virginia	24	25
Wyoming	109	83
Others—HI-1; ID-1; NV-1; TN-1; VA-1; WA-1	6	5
Total US	**1,737**	**1,436**
Total Canada	**502**	**443**
Grand total	**2,239**	**1,879**
Oil rigs	310	202
Gas rigs	1,422	1,230
Total offshore	95	89
Total cum. avg. YTD	**1,618**	**1,345**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in Oil & Gas Journal Energy Database.

SMITH RIG COUNT

Proposed depth, ft	Rig count	9-15-06 Percent footage*	Rig count	9-16-05 Percent footage*
0-2,500	44	—	32	—
2,501-5,000	77	37.6	59	37.2
5,001-7,500	234	23.5	157	19.7
7,501-10,000	395	5.8	324	2.7
10,001-12,500	399	2.2	320	1.2
12,501-15,000	290	0.3	289	—
15,001-17,500	110	—	117	—
17,501-20,000	73	—	51	—
20,001-over	32	—	19	—
Total	**1,654**	**7.0**	**1,368**	**4.8**
INLAND	41		42	
LAND	1,548		1,259	
OFFSHORE	65		67	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in Oil & Gas Journal Energy Database.

OGJ PRODUCTION REPORT

	[1]9-15-06	[2]9-16-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	736	823
California	673	694
Colorado	57	50
Florida	6	6
Illinois	28	31
Kansas	89	93
Louisiana	1,319	750
Michigan	14	17
Mississippi	48	41
Montana	89	95
New Mexico	157	159
North Dakota	103	99
Oklahoma	170	169
Texas	1,323	1,222
Utah	43	45
Wyoming	140	140
All others	69	75
Total	**5,083**	**4,530**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

US CRUDE PRICES

$/bbl*	9-15-06
Alaska-North Slope 27°	66.71
South Louisiana Sweet	59.00
California-Kern River 13°	51.70
Lost Hills 30°	59.05
Wyoming Sweet	63.58
East Texas Sweet	61.43
West Texas Sour 34°	51.25
West Texas Intermediate	60.00
Oklahoma Sweet	60.00
Texas Upper Gulf Coast	66.75
Michigan Sour	53.00
Kansas Common	59.00
North Dakota Sweet	52.50

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

Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

WORLD CRUDE PRICES

$/bbl[1]	9-8-06
United Kingdom-Brent 38°	65.64
Russia-Urals 32°	61.55
Saudi Light 34°	62.34
Dubai Fateh 32°	64.45
Algeria Saharan 44°	67.66
Nigeria-Bonny Light 37°	68.46
Indonesia-Minas 34°	66.47
Venezuela-Tia Juana Light 31°	61.61
Mexico-Isthmus 33°	61.50
OPEC basket	64.64
Total OPEC[2]	63.38
Total non-OPEC[2]	61.10
Total world[2]	62.02
US imports[3]	60.49

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in Oil & Gas Journal Energy Database.

US NATURAL GAS STORAGE[1]

	9-8-06	9-1-06	Change
	Bcf		
Producing region	886	853	33
Consuming region east	1,781	1,716	65
Consuming region west	417	407	10
Total US	**3,084**	**2,976**	**108**
	June 06	**June 05**	**Change, %**
Total US[2]	**2,617**	**2,197**	**19.1**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in Oil & Gas Journal Energy Database

World oil balance

	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.	2005 2nd qtr.	2005 1st qtr.	2004 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	20.76	21.07	21.09	20.88	20.98	21.33
Canada	2.18	2.23	2.24	2.24	2.36	2.35
Mexico	2.08	2.10	2.06	2.11	2.04	2.01
Japan	5.96	5.46	5.03	4.94	6.00	5.45
South Korea	2.28	2.23	2.01	2.07	2.40	2.27
France	2.10	1.96	2.00	1.93	2.11	2.00
Italy	1.86	1.78	1.68	1.69	1.77	1.91
United Kingdom	1.85	1.81	1.81	1.77	1.83	1.80
Germany	2.56	2.63	2.75	2.55	2.54	2.74
Other OECD Europe	7.37	7.45	7.31	7.21	7.33	7.53
Australia & New Zealand	1.07	1.10	1.04	1.06	1.04	1.05
Total OECD	**50.07**	**49.82**	**49.02**	**48.45**	**50.40**	**50.44**
NON-OECD						
China	7.15	7.14	6.93	6.89	6.62	6.42
FSU	4.40	4.60	4.04	3.81	4.30	4.53
Non-OECD Europe	0.74	0.69	0.64	0.69	0.74	0.69
Other Asia	8.39	9.06	8.43	8.71	8.34	8.78
Other non-OECD	14.42	14.14	15.14	14.91	14.84	14.62
Total non-OECD	**35.10**	**35.63**	**35.18**	**35.01**	**34.84**	**35.04**
TOTAL DEMAND	**85.17**	**85.45**	**84.20**	**83.46**	**85.24**	**85.48**
SUPPLY						
OECD						
US	8.18	7.56	7.93	8.80	8.72	8.69
Canada	3.22	3.28	3.02	3.06	3.01	3.13
Mexico	3.80	3.75	3.72	3.89	3.77	3.79
North Sea	5.13	5.05	4.95	5.22	5.46	5.54
Other OECD	1.44	1.51	1.55	1.57	1.49	1.44
Total OECD	**21.77**	**21.15**	**21.17**	**22.54**	**22.45**	**22.59**
NON-OECD						
FSU	11.97	12.09	11.72	11.62	11.53	11.58
China	3.83	3.75	3.80	3.76	3.73	3.69
Other non-OECD	12.98	13.26	13.03	12.59	12.41	12.46
Total non-OECD, non-OPEC	**28.78**	**29.10**	**28.55**	**27.97**	**27.67**	**27.73**
OPEC	**33.84**	**34.23**	**34.48**	**34.18**	**33.99**	**34.62**
TOTAL SUPPLY	**84.39**	**84.48**	**84.20**	**84.69**	**84.11**	**84.94**
Stock change	**–0.78**	**–0.97**	**—**	**1.23**	**–1.13**	**–0.54**

Source: DOE International Petroleum Monthly.
Data available in Oil & Gas Journal Energy Database.

US petroleum imports from source country

	June 2006	May 2006	Average YTD 2006	Average YTD 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	740	643	583	455	128	28.1
Kuwait	201	226	167	194	–27	–13.9
Nigeria	1,094	1,189	1,188	1,127	61	5.4
Saudi Arabia	1,522	1,492	1,464	1,581	–117	–7.4
Venezuela	1,306	1,470	1,453	1,548	–131	–8.3
Other OPEC	786	762	648	622	26	4.2
Total OPEC	**5,649**	**5,782**	**5,503**	**5,563**	**–60**	**–1.1**
Angola	565	391	467	438	29	6.6
Canada	2,258	2,313	2,273	2,128	145	6.8
Mexico	1,855	1,710	1,797	1,657	140	8.4
Norway	140	199	193	248	–55	–22.2
United Kingdom	355	349	286	371	–85	–22.9
Virgin Islands	273	373	297	327	–30	–9.2
Other non-OPEC	3,049	3,106	2,772	2,636	136	5.2
Total non-OPEC	**8,495**	**8,441**	**8,085**	**7,805**	**280**	**3.6**
Total imports	**14,144**	**14,223**	**13,588**	**13,368**	**220**	**1.6**

Source: DOE Monthly Energy Review.
Data available in Oil & Gas Journal Energy Database.

OECD total net oil imports

	May 2006	Apr. 2006	Mar. 2006	May 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,303	–1,171	–1,250	–1,052	–251	23.9
US	12,862	11,951	11,711	12,094	768	6.4
Mexico	–1,761	–1,682	–1,822	–1,860	99	–5.3
France	1,762	1,772	2,106	1,912	–150	–7.8
Germany	2,358	2,349	2,370	2,385	–27	–1.1
Italy	1,379	1,436	1,647	1,505	–126	–8.4
Netherlands	868	934	851	1,168	–300	–25.7
Spain	1,457	1,558	1,644	1,493	–36	–2.4
Other importers	3,725	3,666	3,852	3,718	7	0.2
Norway	–2,326	–2,511	–2,741	–2,976	650	–21.8
United Kingdom	240	122	109	–187	427	–228.3
Total OECD Europe	**9,463**	**9,326**	**9,838**	**9,018**	**445**	**4.9**
Japan	4,970	5,123	6,405	5,200	–230	–4.4
South Korea	2,374	2,271	2,028	2,324	50	2.2
Other OECD	1,117	938	964	764	353	46.2
Total OECD	**27,722**	**26,756**	**27,874**	**26,488**	**1,234**	**4.7**

Source: DOE International Petroleum Monthly
Data available in Oil & Gas Journal Energy Database.

OECD* total gross imports from OPEC

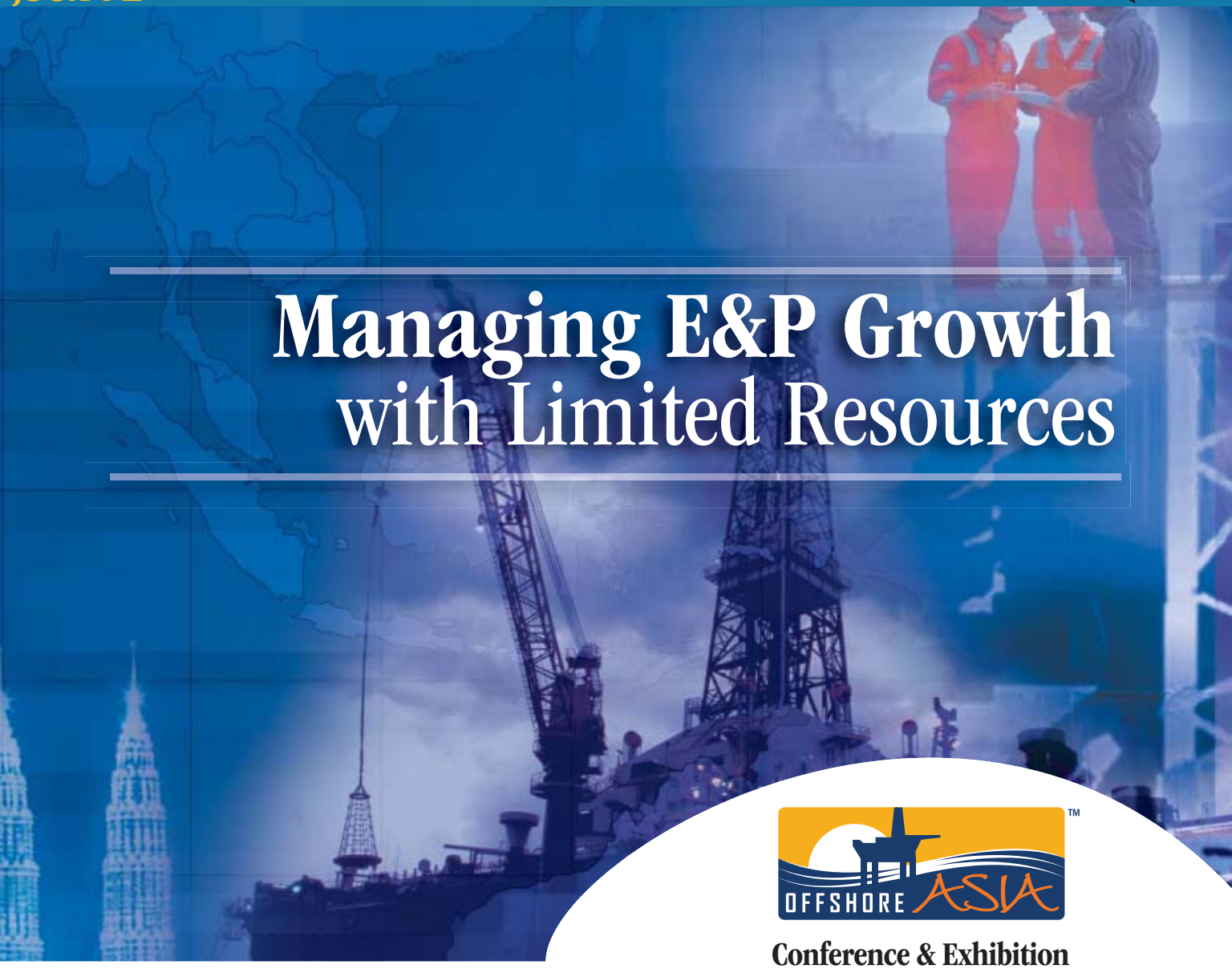
	May 2006	Apr. 2006	Mar. 2006	May 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	272	356	375	366	–94	–25.7
US	5,782	5,477	5,138	5,637	145	2.6
Mexico	10	—	16	—	10	—
France	779	782	725	783	–4	–0.5
Germany	494	504	415	587	–93	–15.8
Italy	985	1,071	1,153	1,288	–303	–23.5
Netherlands	517	540	710	614	–97	–15.8
Spain	674	783	822	764	–90	–11.8
Other importers	1,093	1,265	1,147	1,098	–5	–0.5
United Kingdom	267	188	114	143	124	86.7
Total OECD Europe	**4,809**	**5,133**	**5,086**	**5,277**	**–468**	**–8.9**
Japan	4,277	4,799	5,204	4,615	–338	–7.3
South Korea	2,469	2,294	2,038	2,406	63	2.6
Other OECD	745	544	613	829	–84	–10.1
Total OECD	**18,364**	**18,603**	**18,470**	**19,130**	**–766**	**–4.0**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly.
Data available in Oil & Gas Journal Energy Database.

Oil stocks in OECD countries*

	May 2006	Apr. 2006	Mar. 2006	May 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	194	196	196	197	–3	–1.5
Germany	280	282	280	280	—	—
Italy	130	132	132	132	–2	–1.5
United Kingdom	105	103	98	107	–2	–1.9
Other OECD Europe	654	648	650	642	12	1.9
Total OECD Europe	**1,363**	**1,361**	**1,356**	**1,358**	**5**	**0.4**
Canada	169	173	170	164	5	3.0
US	1,724	1,701	1,692	1,724	—	—
Japan	634	618	620	624	10	1.6
South Korea	152	144	137	151	1	0.7
Other OECD	106	107	102	104	2	1.9
Total OECD	**4,148**	**4,104**	**4,077**	**4,125**	**23**	**0.6**

*End of period.
Source: DOE International Petroleum Monthly Report.
Data available in Oil & Gas Journal Energy Database.



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Dr. K. Aminian
Chair, Faculty Search Committee
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Reserves numbers aren't oil's only market perplexity

Numbers about the oil and gas market aren't always what they seem to be.

It's forever disturbing, for example, to see elaborate arithmetic performed with reserves data.

Nobody can measure oil and gas reserves. The numbers are estimates based on interpretation—often quite a lot of interpretation—of sparse data about indirect indicators like well and seismic information.

The Editor's Perspective

by Bob Tippee, Editor

Yet people who don't know better see numbers and assume they represent measurements, as if from some geophysical dipstick. Reserves aren't measurable and probably won't be anytime soon.

Even market factors that are, unlike reserves, at least theoretically measurable can be just as difficult in the vast, complex, and politically influenced oil and gas business. In its Oil Market Report this month, the International Energy Agency discusses vagaries of numbers representing global oil supply and demand, which of course play no small role in determining oil prices.

IEA calls attention to a category in its monthly oil-balance table called "miscellaneous to balance."

This is the rubber ruler of petroleum economics, an important tenet of which is that supply and demand always balance, net of inventory changes, at some price. The numbers, though, never add up.

The problem isn't the theory but rather the myriad measurements in the equation. Some of them turn out to be nearly as reliant as reserves are on estimation and interpretation. Into this category fall such vital numbers as Chinese demand and inventories outside industrialized countries.

IEA addressed the difficulty in its report because the miscellaneous number reached a hefty 1.3 million b/d in the second quarter.

In addition to the timing disparities and fuzzy-number areas that always bedevil oil balances, IEA said, the growth category of ethanol and biodiesel demand has become a challenge. And many countries still won't publish important data.

Adjusting for estimated errors in the uncertain categories brings the miscellaneous fudge factor down to 300,000-400,000 b/d. That, IEA says, allows analysis to focus on fundamental issues: economic growth, tight diesel and jet-fuel markets, hurricane threats, and geopolitical and project-completion risks.

Just don't forget that the adjustments, no matter how carefully estimated they might be, still can be wrong.

(Online Sept. 15, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Natural gas futures price hits 2-year low

Natural gas futures fell below $5/MMbtu Sept. 14 to the lowest level in 2 years on the New York market after the US Energy Information Administration reported a large leap in US gas storage.

EIA reported the injection of 108 bcf of gas into US underground storage during the week ended Sept. 8 (OGJ Online, Sept. 14, 2006). That was the first triple-digit increase since June 3, 2005, up substantially from 71 bcf the previous week and 89 bcf during the same period a year ago. Gas injections normally increase during the week of the US Labor Day holiday—this year on Sept. 4—when power plants' demand for gas is curtailed because of closed offices and factories.

That brought total US gas storage above 3 tcf, up 339 bcf from the same period last year and 341 bcf above the 5-year average. It also was the earliest time by 2 weeks that US gas storage passed the 3 tcf mark, said analysts at Enerfax Daily. "Mild weather since the start of August decreased power plant demand for natural gas and let storage caverns fill quickly," they said.

In a separate report, analysts in the Houston office of Raymond James & Associates Inc., said, "It now appears as if we are going to test full storage, which means more volatility and the chance of gas-on-gas competition likely. This will lower prices in certain regions until producers start shutting in when no more injections in the system are possible."

Raymond James analysts said, "Historically, we have never seen higher than 3.4 tcf in storage, and we estimate that the most that can go in is approximately 3.5 tcf. If storage continues this build and we start the year with unprecedented levels, this may have a meaningful impact on 'resetting' forces in 2007.

The October gas contract fell 55.7¢ to $4.89/MMbtu Sept. 14 on the New York Mercantile Exchange, but regained 9¢ in the next session.

OPEC outlook

As expected, ministers of the Organization of the Petroleum Exporting Countries made no changes in their official production quota during a brief meeting Sept. 11 in Vienna. But that lack of action did not signal "simple maintenance of the status quo," said Paul Horsnell at Barclays Capital Inc., London.

Statements issued by OPEC at the end of previous meetings "explicitly expressed a commitment to the 28 million b/d target ceiling or clearly stated that ministers had chosen to maintain the status quo," Horsnell noted. But there was no such message in September. Instead, Horsnell perceived "a signal that [OPEC] output will fall further if needed, without necessarily having to make explicit short-term changes in the target ceiling." Horsnell said, "Indeed, combine the lack of commitment to the ceiling with the observations made in the communiqué first that supply exceeds demand, and second that OPEC will balance supply and demand, and there is the strong implication that actual output cuts are a base case unless prices rebound.

"The line is being drawn not very far below current price levels, if not at current price levels. While prices in the $70s were not going to be proactively defended, the $60s are a different proposition," Horsnell said.

The primary topic at the meeting "was clearly the determination of a price floor, below which OPEC should cut its production," said Frederic Lasserre, head of commodities research at the Societe Generale (SG) corporate investment-banking group. He said, "The organization is more worried by the short-term prospects than by the medium-term ones. For instance, the Saudi oil minister confirms 2007 oil demand prospects remain very positive despite the expected slowdown in the US and world economic growth while the OPEC president had to remind [members] the organization does not have any official floor to defend."

Lasserre said, "Since OPEC has officially abandoned any official price band, the debate on the floor has been useless as the market has been more or less a one-way market. Over the last 2 years, the key concern was more the price level [that] would damage the world economy. From time to time, isolated comments from some members indicated that this floor was more or less 'around $50/bbl' (based on the OPEC basket which is trading now at a discount of $2.70/bbl to Brent ICE). At that time, SG agreed this level would be appropriate to both finance future production without damaging demand."

OPEC said it would reassess market conditions at its next meeting Dec. 14 in Nigeria. Both the International Energy Agency in Paris and the US Department of Energy reduced their forecasts of world demand for crude this year in separate reports Sept. 12.

(Online Sept. 18, 2006; author's e-mail: samf@ogjonline.com)

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ENERGY OF TODAY

ENERGY FOR TOMORROW

An in-depth overview of Egypt's Petroleum Sector

This special has been produced by Star Communications for distribution with OIL&GAS JOURNAL

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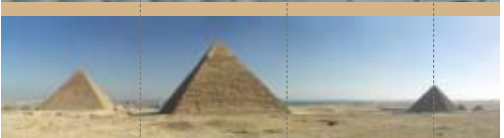

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All production and editing was done by Star Communications. For more information: www.star-communications.us

Writing: John L. Kennedy, 21st Century Energy Advisors, Inc.

Journalism: Jacques Fernández de Santos

Production Development: Susan Brophy

Design & Layout: Dispar Comunicación

Special thanks to Daniel Bernard of Oil and Gas Journal and to the staff of the magazine for their support and cooperation.

Interview with

H. E. Mr. Sameh Fahmy
Minister of Petroleum of Egypt

Q: Egypt is a significant oil and gas producer in the Middle East and Africa, and is fast exceeding its own expectations for reserves. What can you tell us about the real estimates of reserves?

A: The country's oil production has tapered off over the past two decades despite the challenges facing crude oil production and also as a result of the natural decline in production from the mature fields discovered in the 60's and 70's. The Ministry of Petroleum succeeded in maintaining its production levels with a minimum decline rate over the last five years and we currently sit at a little under 700,000 bpd of oil and condensate production.

Today, proven oil and condensate reserves stand at 3.7 billion barrels. Proven gas reserves reached 67 trillion cubic feet (tcf) at the closing of our last calendar year. There also exist an additional 100-120 tcf of potential reserves (according to the studies of international companies operating in Egypt that is compatible with a recent study done by a major reputable international consultant). This study focused on petroleum potential and the future expectations for international offshore reserves. The study reached the distinctive conclusion that Egypt occupies the 2nd place in the total estimates of gas reserves in deep-water, offshore worldwide.

Q: Demand for petroleum products has been relatively flat since 1999 (largely due to the increased use of natural gas). What are Egypt's expectations in terms of exploration?

A: Intensive exploration and production activities are on-going, at about over 30% of Egypt's total area. There are 58 international and private companies currently operating through more than 102 concession agreements including major international companies such as BP, BG, ENI, Shell, Apache and Petronas, amongst others.

During the last two years about 63 agreements and amendments were signed with financial commitments reaching $2,188,130 billion and with the drilling of more than 258 wells. This significant number of agreements reflects the willingness of IOC to invest in Egypt for its significant potential in the oil and gas sector and for the discoveries achieved in the last few years (especially in the Mediterranean, Nile Delta and Western desert). Exploration activities are currently directed for new frontier areas in the Red Sea, Upper Egypt and Western Desert and offshore in the Western portion of the Mediterranean deep-water area.

In addition to the above, a new holding company called "GANOPE" was formed in 2003 following the Ministry of Petroleum's strategy to enhance exploration activities in the Upper Egypt area and has since succeeded by offering three rounds of bidding. It has also announced the fourth round of bidding and has made great progress in attracting companies to explore within its vast territory. It has awarded seven blocks in the Upper Egypt and the Red Sea area and the first exploratory well will be drilled before the end of this year.

Q: What are the output perspectives in Egypt's four traditional areas; the Gulf of Suez (about 50%), the Western Desert, the Eastern Desert and the Sinai Peninsula?

A: Of the country's most known producing regions, the Gulf of Suez, is synonymous with being mainly an oil rich area, and despite the fact that production in the area is on the decline, international and national oil companies have not yet given up hope on

making further oil discoveries. For example, in 2003 the largest oil discovery was made to date with proven oil reserves about 80 mmbbls and an expected rate of 45,000 bpd after field development. Additionally in 2004, there was another major discovery in the offshore area by the National Company with proven reserves up to 60 mmbbls oil, (currently the field was producing about 15,000 bpd with the potential to produce 30,000 bpd with full field development.)

Q: Offshore oil production possibilities in the Mediterranean are beginning to be explored; can you please expand on this?

A: Due to extensive exploration activities all over the country, especially in the deep and ultra-deep water of the Mediterranean (as well as onshore the Nile Delta and Western Desert last year) several gas discoveries were achieved. We expect to increase these discoveries as we are offering additional bidding rounds every year through several entities: EGPC, EGAS and GANOPE. Furthermore, offshore Mediterranean is achieving a phenomena record of successful drilling. Recently, oil was discovered in the Mediterranean and Nile delta (which have always been considered gas producing areas. These discoveries will open more opportunities for finding more oil reserves in the deeper targets.

Q: The government has plans to increase production of lighter products, petrochemicals, and higher octane gasoline by expanding and upgrading existing facilities?

A: Upgrading refining efficiency, improving profitability, and meeting the worldwide demand are some of our main policies. In addition, all of our plants must meet the required regulations set out by the international community.

While aiming to improve the overall quality of our products we must address environmental issues by developing ways to reduce pollution, while increasing production of middle distillates with higher added values.

Promoting this goal we now possess one of the most sophisticated and advanced refineries in the Middle East (MIDOR). It is a state of the art refinery with a capacity of five million tons per year to produce state-of-the-art petroleum products that comply with European standards and also satisfy local demands. Once achieved, we can also export the surplus to international markets. In 2005, the company successfully exported 1.65 million tons of high-octane gasoline and jet fuel with a total value of about one billion dollars (US). Our list of exporters include:

H. E. Mr. Sameh Fahmy, egyptian Minister of Petroleum

England, United States, Canada, France, Spain, Italy, India, Singapore, Jordan, Saudi Arabia, and UAE.

In addition, we have two major companies that are devoted to the production of high quality refined products. First being, Alexandria National Refining and Petrochemical Company; ANRPC that produces unleaded high-octane gasoline and Alexandria Mineral Oil company AMOC that converts heavy distillates to gas oil and naphtha production.

Q: The Ministry is considering one project with a capacity of 200,000 to 300,000 bbl/d, to be co-located with a major petrochemicals complex. If built, it would be primarily an export oriented facility?

A: This comprehensive ambitious complex is under study to produce highquality, clean-burning transport fuels and petrochemical intermediates that meet the strictest European standards.

It is set to be one of the top 20 complexes in the world. It consists of eight main projects namely; a sophisticated refinery for the production of high quality gas-oil, unleaded gasoline, naphtha and kerosene. In addition, there are another five projects that would produce ethylene and polyethylene, propylene and poly-propylene, styrene and aromatics. There is also a project for power and steam generation and another for transportation and storage utilities. Estimated total investment of the projects is approximately 9.5 billion $US with a capacity of 350,000 bbl/d. This huge complex is expected to create about 100,000 job opportunities during its construction and implementation phases, which is considered in itself an added economic value and the implementation of the complex will take around five years.

Q: What will be the political and economic criteria for conceding exploration blocks in the near future?

A: The Ministry of Petroleum restructured the oil sector establishing new specialized entities for oil, gas and petrochemicals (EGAS, ECHEM and GANOPE in addition to EGPC) to speed up the decision-making process and focus on growing activities in the gas and petrochemical sectors, as well as further extend the oil and gas activities in Upper Egypt. They participate in joint-venture partnerships with international oil companies operating in Egypt. The state-owned entities are in charge of offering acreage for tender in international bidding rounds and recently, several bidding rounds were announced offering a multitude of opportunities for E & P companies.

As in the past, the petroleum sector still plays an important role in the country's economy. We succeeded in attracting $10 billion of FDI in the past five years compared with $5.6 billion during 1996-2000, and $3.5 billion during 1991-1995. The petroleum sector has set an economic model for investment and the main point of our strategy is to increase our petroleum product's exports, reduce the burden on the state's budget, and attract more private and Arab international investments. Our projections for the next five years are to attract approximately 20 billion US dollars of international and national investments, with $16 billion as FDI, 50% of which will be invested in upstream activities.

Egypt's petroleum future:

Critical assets and well-defined plans will add value to large resources

To keep pace with the relentless growth in global energy demand in the decades ahead, it will be necessary to find, develop and use more oil and gas more efficiently, and with less impact on the environment.

Meeting tomorrow's energy demand will require a complex array of talents and assets. Adequate oil and gas resources coupled with convenient access to both raw materials and markets will be critical advantages in tomorrow's competitive global energy marketplace.

Just as important, the leaders that emerge to take up the challenge will be those nations and corporations that encourage innovation, offer attractive investment opportunities and strive to improve living standards for all citizens.

For decades, Egypt has taken advantage of its strategic location to build an important link in the chain that connects large oil reserves with markets around the world. In the last decade, it has begun to implement a long term strategy to add value to its own considerable natural gas resources by building a strong export prominence and a world-class petrochemical industry.

Egypt's participation in the critical transportation infrastructure built around the Suez Canal and the Suez Mediterranean (Sumed) pipeline is one of the country's most important physical assets. Egypt's late President Saddat saw the pipeline as a strategic project and together with the Canal, the two now transfer around 98% of Arabian Gulf crude oil to the Mediterranean.

In addition to its ongoing role as a leading global oil transportation hub, Egypt also has:

- An aggressive exploration effort underway to further define its natural gas resource, much of which lies in deep water
- A Master Plan to develop its petrochemical industry and expand natural gas and liquefied natural gas (LNG) exports
- A reputation as a politically stable, investment-friendly country with a long history of partnering with international companies of all types
- A focus on environmental responsibility that embraces both operations within Egypt and the products it produces for consumers around the world

SUMED pipeline is one of the country's most important physical assets.

Adding to the resource

In fiscal year 2004/2005, Egypt's oil production averaged 641,000 barrels per day (b/d) of crude and condensate; gas production averaged about 3.8 billion cubic feet per day (cu ft/day). At year end, remaining oil reserves were estimated at 3.669 billion barrels (bbl) and natural gas reserves stood at over 66 trillion cubic feet (tcf).

"These discoveries in the Mediterranean and Nile Delta open more opportunities for finding more oil reserves in the deeper targets." Petroleum Minister Sameh Fahmy

In addition to proven gas reserves, much of the country's future will be driven by an estimated 100-120 tcf of gas yet to be discovered.

During the last fiscal year, 77 exploration wells resulted in 38 oil and five gas discoveries that added 196 million bbl of oil and 0.8 tcf of gas to Egypt's reserves base. Production wells drilled or re-completed totaled 230, most of which were completed in the Western Desert.

Also during the year, 23 agreements were signed and amended that include financial obligations totaling $899 million and the commitment to drill 96 wells.

The continued search for new reserves by both Egyptian and international companies in recent years has helped slow the inevitable decline in oil production from fields discovered in the 1960s and 1970s.

In 2003, for example, the biggest oil discovery in 14 years added reserves of about 80 million bbl. When developed, the field is expected to produce 45,000 b/d, according to Minister of Petroleum H.E. Eng. Sameh Fahmy. In 2004, another big oil discovery offshore proved reserves of 60 million bbl. After full development, the field could produce 30,000 b/d.

In early 2006, five new oil discoveries were made in the Gulf of Suez and the Western Desert. The Gulf of Suez accounts for about half of Egypt's production, the rest is from its three other key areas: The Western Desert, the Eastern Desert and the Sinai Peninsula.

"The Gulf of Suez is likely to continue to be the main oil producing region," said Petroleum Minister Fahmy.

But aggressive exploration in the Western Desert has resulted in significant oil and gas discoveries in recent years. The search also has been intense in the deep water of the Mediterranean, and onshore in the Nile Delta and Western Desert, resulting in several gas discoveries. Recently, oil discoveries have been made in the Mediterranean and Nile Delta, areas traditionally considered gas-prone.

President Hosny Mubarak and Minister of Petroleum Sameh Fahmy indicate towards a model of the Idku terminal during a press conference.

"These discoveries open more opportunities to find additional oil reserves in the deeper targets," said Petroleum Minister Fahmy.

Egyptian General Petroleum Corp. (EGPC), in its strategy to achieve the goals of the Ministry of Petroleum to increase the country's petroleum wealth, will:

- Tender new open areas in different sedimentary basins with international bid rounds
- Improve and upgrade the petroleum agreement process to lure more investment
- Apply the latest exploration and exploitation technologies
- Use exploration theories to reduce risk and increase success

Downstream development

Crude oil and natural gas reserves are fundamental to Egypt's energy future. But adding value to those raw materials by producing products for a broad range of markets is the key to economic growth and stability.

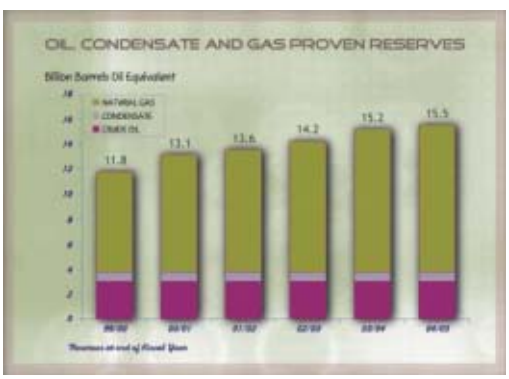
Being competitive in tomorrow's refined product market will require a lighter product slate, improved plant efficiency and lower cost, and those are key objectives of expansion and upgrading projects underway and planned for Egypt's refineries.

"We devote our attention to addressing environmental issues by developing ways to reduce pollution, increasing the production of middle distillates with higher added values, and improving product quality," said Petroleum Minister Fahmy.

Egypt's state-of-the art Middle East Oil Refinery (Midor), for example, can produce 5 million metric tons per year of petroleum products that meet European standards.

Other companies also produce high quality refined products. Alexandria National Refining and Petrochemical Co. (Anrpc) makes unleaded high octane gasoline and Alexandria Mineral Oil Co. (AMOC) converts heavy distillates to gas oil and produces naphtha.

Along with the inexorable growth in demand for refined products, global economic expansion and a rising world population will drive increased demand for petrochemical products. Egypt's Master Plan to become a leading petrochemical manufacturer is designed to take full advantage of that opportunity.



"Egypt's abundant natural gas resources and its ability to move downstream to produce higher added-value products will have a positive impact on the country's economy," said Ms. Sanaa A. Moneim El Banna, Chairperson, Egyptian Petrochemicals Holding Co. (Echem).

As petrochemical feedstock costs rise, proximity to gas supply becomes an important competitive advantage. Areas such as the northeastern coast of Egypt that have relatively low-cost feedstock represent an attractive investment opportunity, said Ms. Moneim El Banna.

Partners and investment welcome

Participation of a broad cross section of international and private companies in exploration and production activities that span 30% of Egypt is just one indication of the opportunities available in the country.

About 58 firms, including BP, BG Group, Eni, Shell, Apache, Petronas and others are currently operating under 102 concession agreements. In the last two years, 63 agreements and amendments were signed that involved financial obligations totaling $2.188 billion and commitments to drill a total of 258 wells.

Since its creation in 2003 to enhance exploration in Upper Egypt, Ganoub El Wadi Petroleum Holding Co. (Ganope) has held three bid rounds and announced a fourth. The company has awarded seven blocks in Upper Egypt and the Red Sea and the first exploratory well will be drilled before the end of this year.

"The company has made great progress in attracting companies to explore within its vast territory," said Petroleum Minister Fahmy.

Before Ganope was established, only 6% of Egypt's working area was covered by exploration and production (E&P) agreements; now 26% is under production sharing agreements (PSA).

More than 25 new concessions are planned for 2007.

"Our plan is to issue at least one international bid round per year," said Eng. Hassan M. Akl, Ganope Chairman. With seven agreements in place; he expects to have 15 by the end of 2006 and 25 agreements by 2008.

Technical competence

Technology is increasingly critical to competitive success throughout the petroleum value chain. In response to that trend, Egypt is becoming an important exporter of expertise, building projects in Saudi Arabia, Syria, Sudan, Jordan and elsewhere.

"Having access to technology means working closely with technology owners, including international companies," according to EGAS experts. "We often begin with a number of foreign experts, then build our capability to the point where Egyptians dominate operations."

Other Egyptian companies also follow this process, including Engineering for the Petroleum and Process Industries (Enppi), Egyptian Drilling Co., Petroleum Maritime Services (PMS) and Petroleum Projects and Technical Consultation Co. (Petrojet).

Petrojet began working overseas three years ago, and now gets 40% of its revenues from outside Egypt, said Eng. Hany Dahy, Chairman.

By the end of 2006, Enppi's business abroad will account for 30% of revenue, said Eng. Fakhry Eid, Chairman.

"We are planning to reach 50% abroad in the future," he said. "Our vision is to make Enppi one of the top 10 engineering/procurement/construction (EPC) contractors in the Middle East/North Africa region."

Suez Canal and Sumed:

New transportation services keep Egypt at center of global oil trade

When the idea of linking the Mediterranean Sea and the Red Sea with a navigable waterway first occurred to the Pharaohs, the commercial world was a far smaller place. As trade expanded over the centuries, so did the value of a route that would connect Europe, the Middle East, Africa and Asia that did not require a long trip around the southern tip of Africa.

Turning that ancient idea into today's reality took centuries and claimed many lives before Egypt's Suez Canal was finally inaugurated in 1869. But it now is one of the world's most strategic trade routes, shortening the distance between most of the world's markets.

At the heart of international trade and commerce, Egypt today can competitively supply a market of one billion people.

As important as the Canal became to moving goods from source to consumer, however, the growing importance to the world of Middle Eastern oil called for additional capacity and a different kind of transportation facility.

That need was met by the 320-km Suez Mediterranean (Sumed) pipeline system linking Ain Sukhna on the Gulf of Suez to Sidi Kerir on the Mediterranean. Sumed's twin parallel 42-in. pipelines, with a design capacity of 117 million tons/year, has been in operation since 1977 as a companion to the Suez Canal for transporting oil from the Arabian Gulf region to the Mediterranean.

Through 2004, it had transported more than 16 billion bbl.

A regional alliance, Sumed is owned by EGPC, 50%; Saudi Arabian Oil Co., 15%; three Kuwait firms, 15%; the International Petroleum Investment Co. IPIC (Abu Dhabi), 15%; and Qatar Petroleum Corp., 5%.

The pipeline system is part of the local and international long-term political vision that has remained unchanged since the presidency of Gamal Abdel-Nasser.

Suez Canal: Improvement continues

The Pharaohs dug a canal linking the Mediterranean and the Red Sea through the eastern branch of the Nile Delta but it remained neglected. The Greeks, then the Romans dug it several times, but it was again neglected. Dug once again at the time of the Arab conquest of Egypt, the Canal existed for a time, but was later filled up.

The enduring idea was finally set on the path to reality in 1854 when French engineer Ferdinand De-lesseps signed an agreement with the Egyptian Government to dig the Canal. Digging began in 1859, coincidentally the year that the first commercial oil well was drilled in the US. For 10 years, more than 2.4 million Egyptian workers worked on the Canal; more than 125,000 lost their lives.

In 1869, the Suez Canal was finally opened for navigation. In July 1956, Egypt nationalized the Canal after it had been an international company for 87 years.

With a total length of 192 km, Suez remains the world's longest canal without locks. Today, it transports 14% of total world trade, 26% of oil exports and 41% of the total volume of goods and cargo that reach Arabian Gulf ports. It can handle about 25,000 vessels annually.

About 3,300 oil tankers passed through the Suez Canal in 2004, a 20% increase in tanker traffic from 2003. Total northbound and southbound oil shipments increased from 1.4 to 1.7 million b/d between 2003 and 2004. Transit in the Canal employs a convoy system. The northbound convoy consists of two groups and southbound traffic includes two convoys.

There are no length restrictions for ships traversing the Canal. Currently, the Canal can accommodate 'Suezmax' class tankers with drafts to 62 ft and 200,000 dead-weight-ton (dwt) maximum cargos. Depending on the type of vessel and its load, speed is limited to 11-16 km/hr; an average transit time is about 14 hours.

A state of the art facility has emerged at Port Said East as a trans-shipment centre for the Eastern Mediterranean and the Northern entrance to the Suez Canal.

In 2001, the Suez Canal Authority (SCA) launched a 5-year program to reduce average tanker transit times to 11 hours. The SCA also is moving ahead with a 10-year project to widen and deepen the Canal. By 2010, it will be able to accommodate very large crude carrier (VLCC) and ultra large crude carrier (ULCC) class tankers with oil cargos of up to 350,000 dwt.

Sumed: Stable, economical, flexible

The Sumed system includes the terminal at Ain Sukhna where up to four tankers of any size can discharge their cargo simultaneously. At the other end of the pipeline, Sidi Kerir terminal can load five tankers of up to 400,000 dwt at the same time. Large tank farms at each terminal provide spare storage capacity and pipeline operating flexibility that helps meet customers' varied requirements.

Original capacity of the Sumed system was about 1.6 million b/d. It has grown to about 2.4 million b/d currently and is operating at about 96% of design capacity, said Eng. Moustafa Gomaa, Chairman of Arab Petroleum Pipelines Co. Future capacity increases will depend on crude oil market conditions, he said.

As political tensions grow, Egypt's access to the Mediterranean for Middle East oil becomes increasingly valuable.

"This is especially true since Sidi Kerir has become one of the important storage areas in the Mediterranean," said Eng. Gomaa. "As we keep the Sumed pipeline the safest route to the Mediterranean, it also provides continuous stability for oil flow from the Arabian Gulf countries to Europe."

From the Mediterranean, oil can reach southern Europe in three days and northern Europe in seven days. The pipeline system can help deliver Arabian Gulf crude to European refineries 15-22 days earlier than a tanker making the journey around Africa's Cape of Good Hope.

"Regardless of the situation, Sumed has proved that it is the most economical way to move crude from the Arabian Gulf to Europe," said Eng. Gomaa.

In 2004, about 65% of deliveries to Ain Sukhna came from Saudi Arabia, 24% from Iran, 6% from Egypt, 4% from Kuwait. About 35% of the crude lifted from Sidi Kerir during the year went to the eastern Mediterranean, 26% to the western Mediterranean, 34% to northwest Europe and 5% to the US.

Adequate storage and pumping capacity are keys to the flexibility of the Sumed system.

"As we keep the Sumed pipeline the safest route to the Mediterranean, Sumed also provides continuous stability for oil flow from the Arabian Gulf countries to Europe." Eng. Mr. Mostafa Gomaa, Chairman of Sumed Arab Pipeline

Fifteen double deck floating roof storage tanks at Ain Sukhna terminal have a total capacity of 1.5 million cubic meters (cu m). Two pumping stations—one for each pipeline— can each pump at rates to 9,300 cu m/hour. A boosting station at Dahshour is equipped with six pumps.

Sidi Kerir has 24 floating roof tanks with a total capacity of 2.6 million cu m. Five pump stations load crude, each connected to one group of tanks. The de-ballasting plant at the terminal treats ballast water, delivering clean water with less than 10 parts per million (ppm) dissolved solids into the Mediterranean.

Operating in batch mode, the Sumed system is controlled and monitored by a sophisticated integrated supervisory control and data acquisition (Scada) system at the dispatching center at Ain Sukhna. Backup control at Dahshour provides redundancy and

Satellite image of Suez Canal

local control centers are part of the system.

"Our main objective is to assure the customers of Sumed that their products are in safe hands," said Eng. Gomaa. "We strive to do this in the most economical, and with minimum environmental impact."

More than just a transporter

Oil transportation is not the only service Sumed provides. It also helps companies market their crude from Sidi Kerir, which can serve as a stable strategic focal point for sale of oil on a free-on-board (FOB) basis. Shippers discharging a VLCC or ULCC at Ain Sukhna terminal, for example, can tailor liftings from Sidi Kerir in the volumes and types needed by their refineries, FOB customers, or to meet destination port limitations.

This 'cargo tailoring' lowers freight costs and provides flexibility.

Other related services include:

- Stock transfer of crude oil while in Sumed custody
- Cargo topping, a process that avoids dead freight by advancing the balance when a customer's crude type in Sumed custody is less than the tanker size
- Crude oil swap to clear small amounts of a customer's remaining inventory
- Methods to facilitate financial transactions

Innovation has helped the system keep pace with larger vessels and volumes and shifting supplies and markets. Sumed is cooperating with the Suez Canal Authority, for example, on a system of lightering called drop and pick, which was established in 1997. The process makes it possible for a VLCC to be partially unloaded at Sumed's terminal at Ain-Sukhna so the tanker can pass through the Canal safely and reload at Sidi Kerir terminal.

Making it possible for VLCCs to use the Canal, although they cannot transit it fully loaded because of the draft limitation, allows the Sumed/Canal partnership to serve the east coast of North America, as well as other markets.

"This technique has increased our capacity and we hope more users will take advantage of this option," said Eng. Gomaa.

Another project was launched recently to receive Mediterranean and Black Sea crudes at Sidi Kerir terminal for storage and reloading. Growth of Mediterranean, Russian and Caspian exports prompted Sumed to modify two single buoy mooring (SBM) facilities to be able to receive crude at Sidi Kerir and reload it again.

Workers oversee security of plant.

Movement of ships in the Damietta complex.

Storage at Side Kerir provides a buffer to Mediterranean refineries, minimizing their need to invest in storage or maintain large inventories. VLCC cargoes can be accumulated to save freight for the long-haul US-bound cargoes. And Mediterranean crude can be combined with Arabian Gulf crude transported through the pipeline.

Three new tanks with a total capacity of 1.2 million bbl were added to enhance the flexibility of this 'back loading' option.

Another change under consideration is the ability to pump crude from North to South to handle potential exports from the CIS and North Africa to Asia.

"The Sumed pipeline is also very important to the Midor refinery," said Mr. Mahmoud Nazeem, Midor Chairman. Midor currently has an agreement with Saudi Arabia under which almost half of the refinery's crude diet is met with the Saudi crude. That oil must be transported from the receiving port on the Red Sea to Sidi Kerir on the Mediterranean where the other terminal of the refinery's crude supply pipeline is located. Sumed has installed special import facilities at Sidi Kerir to receive Mediterranean crude for Midor.

A community partner

Since it began, part of Sumed's net profit has gone to community development, including the support of many universities and health care facilities in both Suez and Alexandria.

It introduced an up-to-date ultrasonic scanning medical device in the Alexandrian government hospitals, and has financed many facilities for the handicapped in Egypt. The company also focuses on the development of its employees by offering training courses and a health care program for employees and their families.

Environmental protection has also been an ongoing effort. In the mid 1970s, Sumed spent $40 million to build its plant to treat ballast water from tankers. Sumed management continues to be committed to preventing pollution. Along with the ballast water treatment facility, a key part of that effort is the system's sophisticated continuous monitoring capability that provides early warning of any incident. Strategically placed pollution fighting equipment uses the latest technology.

"We also are working under the umbrella of the Ministry of Petroleum and Alexandria University to support research in the industry and to forge a solid link between the university and the industry," said Eng. Gomaa.

Other key pipeline projects

Critical to Egypt's oil and gas strategy are natural gas exports, both by pipeline and as LNG.

The first phase of the Arab Natural Gas Transmission Pipeline, a regional system to serve neighboring countries, was inaugurated in mid 2003. A second phase came on stream at the end of last year. Further expansion is planned to connect Syria and Lebanon, as well as the European gas network through Turkey.

In early 2006, Egyptian Petroleum Minister Fahmy and Turkish Minister of Energy, Helmi Guler, agreed to establish an Egyptian-Turkish company to extend the Arab Gas Pipeline to the Syrian-Turkish border and market gas to Europe.

The first phase of the Arab Natural Gas Transmission Pipeline system, mostly onshore, was completed in 18 months. It connects Al Arish, Egypt to Aqaba in southern Jordan via Taba with a 350-km 36-in. pipeline. The second phase of the system, the Jordanian Gas Transmission Pipeline, extends from Aqaba north 370 km to Rehab, Jordan, also with a 36-in. line.

Egypt's vision for making natural gas an increasingly important component of the country's energy consumption also requires expansion of the domestic distribution system. According to Ganope Chairman Eng. Akl, the national gas grid will be extended from Bani-Swef to the south, and up to Aswan in stages that will add 738 km of pipelines.

"This will create a real industrial revival in all fields, which will have a positive impact on the development of Upper Egypt," said Eng. Akl.

An extension of the petroleum products pipeline from Sohag to Qena then to Aswan is also planned.

All these planned projects will bring direct and indirect job opportunities, environmental improvement, and attractive Upper Egypt projects for investors.

The Egyptian workforce plays a key role in the petrochemical sector.

> **"Our target is to be one of the top five contracting companies around the world in the coming decade."**
>
> Eng. Mr. Hany Dahy, Petrojet Chairman

Pipeline construction expertise

Petrojet, the leading integrated pipeline construction firm in Egypt, has constructed the entire Egyptian national grid of pipelines (oil, gas and products), a total length of more than 17,000 km.

The company executed the first portion of the Egyptian natural gas export pipeline system to Aqaba, as well as the second portion of the pipeline. That 393-km segment of 36-in. was successfully completed 15 months ahead of schedule.

Another significant major project was successfully finished late last year in Libya, said Eng. Dahy, Petrojet Chairman. The 30-in. pipeline, about 725 km long, extends from the Sharara area in the very south of Libya to Mellita in the north. The project was executed by Petrojet on an EPC basis after wining the tender in a fierce international competition.

The project involved construction and schedule challenges. The route traversed very remote areas with soft sand dunes, then it crossed the Hamada plateau with its very hard igneous rocks and altitude differences of as much as 800 m.

A similar pipeline of the same length, diameter required about three years to complete, but this Petrojet project was finished in 10 months, considered a world record, according to Eng. Dahy.

Since its formation in 1975 as a joint stock company capable of competing with foreign contractors in petroleum, Petrojet's goal has been to become a world class player in its field. That vision is built on using state of art technologies, ensuring operational excellence and cost efficiency, and complying with international health safety and environmental standards.

In Egypt, Petrojet is already the foremost oil, gas and petrochemical projects contractor. "Our target is to be one of the top five contracting companies around the world in the coming decade," said Eng. Dahy.

Enppi also was involved in the Arab pipeline system segment from Aqaba to the Jordanian /Syrian border as well as the segment connecting El-Arish to Taba. Phase II of the pipeline system is completed to the Syrian border and the compression station was scheduled to be finished by mid 2006, according to Eng. Eid, Enppi Chairman.

Enppi's other major projects in Egypt include expanding production of ethane and propane, as well as the linear alkaline benzene project to be executed by a consortium that includes Enppi and Petrojet.

During its 28 years, Enppi has completed over 500 major projects. It is the only national company working as an EPC primary contractor on a turnkey basis for oil, gas, petrochemicals and infrastructure either in Egypt or in the Middle East. The company has acquired three major projects this year from Saudi Aramco, Venezuela's PDVSA, and Syria's HPC.

About 97% of Ennpi's shares are held by EGPC. Petrojet holds 2% of the shares, and the Petroleum Housing Fund, 1%.

Egypt's natural gas future:

A world class resource will fuel expanded local use and LNG exports

Egypt's natural gas resource is vital to the country's energy future.

At home, natural gas is steadily replacing oil for commercial, industrial and residential use to the long term benefit of the environment. Beyond Egypt, the world's appetite for clean burning fuel offers great potential to serve a range of markets with both pipeline and LNG exports.

And natural gas is a critical element in Egypt's unfolding Master Plan for a world class petrochemical industry.

To fully exploit these opportunities, the Egyptian Ministry of Petroleum's policy will balance medium term export commitments, local needs and long term strategic requirements.

The country already is on the road to its gas future. During fiscal year 2003/2004, natural gas production reached 1.3 tcf. Electricity generation accounted for about two-thirds of total consumption and the number of residential, commercial and industrial gas users reached 2 million. Egypt also is a leader in natural gas-fueled vehicles with more than 54,000 such vehicles on the road at the end of the year and 83 fueling and conversion stations in place.

Because its emerging natural gas industry is so critical to Egypt's future and implementing its comprehensive gas strategy will be complex, the Petroleum Ministry established the Egyptian Natural Gas Holding Co. (EGAS) to guide activities along the entire chain of natural gas operations.

To execute the country's gas utilization plan over the next two decades, EGAS plans to:

- Increase reserves at an average annual rate of 4/6 tcf
- Meet total demand that is expected to grow at an average annual rate of 4%
- Develop an infrastructure that covers the entire country
- Create a comprehensive plan for expanding the use of compressed natural gas (CNG) in vehicles

Size of the resource

Fundamental to the success of the strategy is a significant proven natural gas resource and the potential for more discoveries, including those in the deep water of the Mediterranean. At the end of fiscal year 2004/2005, Egyptian gas reserves of 67 tcf accounted for more than three-fourths of Egypt's proven hydrocarbon reserves. The bulk of those gas reserves are in the Nile Delta area and in the Mediterranean.

In addition, potential reserves are estimated at 100-120 tcf. One of the most promising sources of gas is the deep water of the Mediterranean, which will be a focus of exploration and development. A recent study ranked Egypt second in the world in potential deep water gas potential.

From 2001 to 2004, two international bid rounds were held and 41 discoveries added about 15 tcf of gas and 127 million bbl of condensate to proven reserves. Petroleum Minister Fahmy signed the first two EGAS concession agreements in the Mediterranean Sea during the period, one for the Tina area and one for the Baltim area. Another international bid including 12 exploration blocks in the Nile Delta, North Sinai onshore and Mediterranean Sea closed in July 2006.

Major discoveries during 2003/2004 fiscal year included Kasr-2 which added 1.8 tcf of reserves and three programs that added 1 tcf each—Raven, Tarot, and Kg 45.

Arab Gas Pipeline, Jordan.

Export facilities: Up and running

Exporting natural gas is a cornerstone of Egypt's oil and gas development strategy, according to Petroleum Minister Fahmy. And gas export operations are off to a fast start. Both the pipeline export of natural gas and LNG exports began almost simultaneously from different locations.

The Arab Natural Gas Transmission Pipeline, a regional system to serve neighboring countries, now extends to Rehab, Jordan and agreements have recently been put in place to expand it to the Syrian-Turkish border, making it possible to market gas to Europe.

At the same time, three LNG trains began shipments within little more than a year. Two or three more LNG trains could be built at either of the existing plants—Damietta or Idku—over the next five years, depending on exploration success, according to Hesham Mekawi, Chairman, BP Egypt.

A final element of the natural gas value chain is natural gas liquids. NGLs extracted at a processing plant put on stream in 2004 provide liquefied petroleum gases (LPG) and condensate for the local market, propane for export and ethane for the production of ethylene and polyethylene.

In 2003/2004, production of LPG, propane and ethane totaled more than 1 million tons; condensate production was about 1 million bbl.

A final element of the natural gas value chain is natural gas liquids. NGLs extracted at a processing plant provide liquefied petroleum gases (LPG).

Already in sixth place

LNG export will be an important driver of Egypt's economic growth and a reliable source of natural gas for world markets far into the future. The country now has two plants on stream and a vision for aggressive expansion. Within four years after EGAS was established, the country became the 6th largest LNG producer in the world.

Damietta, the largest LNG plant with a design capacity of 7.56 billion cu m/year, was put on stream in December 2004 after a record of only 52 months from inception to first shipment. LNG from Damietta is sent to the Spanish market by Union Fenosa, 80% owner of The Egyptian-Spanish Natural Gas Co. (Segas), which operates the facility; and to Mediterranean and US markets by EGAS, 10% owner of Segas.

Two liquefaction trains of the Idku LNG project east of Alexandria, each with a design capacity of 3.6 million tons/year, were put on stream in 2005. Construction of both trains was completed ahead of schedule, Train 1 by three months and Train 2 by nine months.

Beheira Natural Gas Liquefaction Co. owns the first train, output from which will be taken by Gaz de France under a 20-year agreement. Though output from Train 1 has been sold to Gaz de France, BG Group will purchase from Gaz de France about two cargoes of LNG per month between July 2005 and the end of 2006.

BG Group lifted its first LNG cargo from Idku LNG Train 1 on 29 May 2005, some three months ahead of schedule. This was the first of three pre-commissioning cargoes from Train 1.

Idku Natural Gas Liquefaction Co. owns Train 2, which will supply BG Group with LNG for export to the Lake Charles terminal in the US, and to Italy. For about the first three years of LNG production, BG Group intends to send the entire output to Lake Charles. A portion of Train 2 output will then be supplied to the Brindisi LNG import terminal in Italy which BG Group is developing.

Train 2, Idku Natural Gas Liquefaction Co.

Gas fields in the West Delta Deep Marine area of the Mediterranean will be further developed to feed the Idku LNG complex.

Idku uses the proven Phillips liquefaction technology. Total project cost of Trains 1 and 2 was about $1.9 billion. Project financing of $949 million was secured for Train 1 in April 2004 and $880 million was secured for Train 2 in July 2005. The latter includes $320 million to repay the Train 1 owner for Train 2's share of the common facilities.

There is sufficient space at the Idku site for four more LNG trains. BG Group, for example, is seeking reserves that would support a third train through its own exploration program and in partnership with third parties, according to the company.

"We have more than one window to monetize gas reserves." Eng. Mr. Ismail H. Karara, Gasco Chairman

The project's commercial structure has been designed to allow future expansion without the need to involve all existing partners and it is possible that third parties could supply gas to future trains. The Egyptian LNG Co. owns both the Egyptian LNG site and common facilities. Its sister company, Egyptian Operating Company for Natural Gas Liquefaction Projects (Opco), operates all trains.

EGAS role

EGAS was established in 2001 to realize the Ministry of Petroleum's strategy to restructure the petroleum sector in Egypt according to the vision of HE the Minister of Petroleum.

With responsibility for all natural gas activities including exploration, production, transmission, distribution, marketing and export, EGAS will:

- Encourage investments in natural gas activities
- Prepare action plans for natural gas industry and related projects
- Develop techno-economic studies for gas projects
- Manage sales gas transmission & distribution systems and coordinate all related activities
- Develop LNG projects on its own or with national and international partners
- Participate in exploration, development and production from gas discoveries
- Develop the natural gas industry database
- Study and define optimum locations for gas projects

A special focus is to apply advanced exploration techniques and concepts in the search for the potential 120 tcf of undiscovered gas reserves thought to exist. EGAS also will work to expand gas export pipelines to link with the European Gas Pipeline system and implement additional LNG trains.

Leveraging opportunity

Success in all this will require a dedication to regional and international cooperation.

EGAS has a number of exploration concessions with international companies in the Mediterranean and in the Nile Delta onshore. In the near future, EGAS will have approximately 25 concession agreements in place.

The latest bid round, including 12 blocks, nine of them offshore and three onshore, has generated great interest among international companies.

There is more than one way to monetize the reserves found. In addition to exports by both pipeline and LNG, the local market has been expanding in the last five years to accommodate new fertilizer manufacturing, petrochemical and methanol plants.

Egypt has extensive infrastructure and a national pipeline grid that is continuously upgraded to accommodate new production. Most important is Egypt's business expertise, its modern petroleum sector, and its reputation for political stability. Some international companies have been operating in Egypt for more than 40 years.

"We have never been to arbitration, and all our differences with our partners have been amicably resolved." states EGAS insiders.

Throughout the entire oil and gas value chain, the Egyptian petroleum sector has been attracting foreign direct investments of $2-3 billion per year. With the current plan to extend the national gas grid as far as Aswan by 2011, there will be opportunities for investments in pipelines and downstream facilities, as well as new opportunities for exploration.

And Egypt's strategic position makes it possible to serve European, US and even Far East LNG markets at a very competitive cost, he said. The opportunity for more LNG projects exists. There is plenty of room to expand and add many more trains.

LNG Tanks, Western Desert Gas Complex.

The largest LNG plant, Damietta.

Gas Center in Alexandria.

Idku LNG plant.

Serving domestic markets

Gasco has an important role to play in promoting the utilization of gas in Egypt through its presence at every point of the Egyptian gas chain, said Eng. Ismail Karara, Chairman. The company is owned 70% by EGPC, 15% by Petrojet and 15% by EGAS.

Since its establishment in 1997, the company has been responsible for the management, operation, maintenance, development and upgrading of the national gas grid. A pioneer in transmission, distribution, processing and marketing, Gasco has always been a link between natural gas producers and consumers.

That connection now has extended to consumers in neighboring countries. Gasco supplies gas to the Arab Natural Gas Pipeline and transmits natural gas to the Damietta LNG plant where it is exported to Europe.

"In political terms, the Arab Natural Gas Pipeline system helps consolidate Arab integration," said Eng. Karara.

With about 2 million household, commercial and industrial consumers now connected, the plan is to bring that total to 6 million consumers within the coming six years, he said.

Gasco also plays a leading role in gas processing, recovering LPG for local use, an ethane/propane mixture for petrochemical feedstock, and commercial propane for export. As gas processing moved to the forefront of Gasco strategy, the company integrated the operation of the Western Desert Gas complex and the Ameryia LPG recovery plant.

Gasco currently has several projects underway to enhance productivity. One of the projects will boost production of the ethane/propane mix from the Western Desert Gas Complex and Ameryia plant. Scheduled for completion within 30 months at an approximate cost of $200 million, it will almost double production.

Several projects are also in progress to expand the national gas grid. The El Tina-Abu Sultan pipeline will satisfy the demand in Suez, and north of the Gulf of Suez, the Dahshour-Koraimat pipeline will cope with increased demand resulting from expansion of the Koraimat power station. South Valley Pipeline will feed the south of the country, and feasibility studies have been conducted to evaluate a plan to supply natural gas to Sharm El Sheikh and Hurghada.

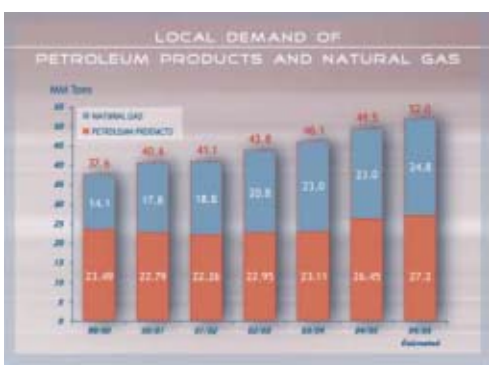
Using technology

Gasco also operates Egypt's National Advanced Control Center (NATA) that provides control for the national gas grid. NATA monitors and regulates the gas flow using a sophisticated communication network that collects data from all pipelines, delivery points, distribution centers and consumption stations in each geographic center and sends them through a

Simian Sienna Gas plant. The bulk of egyptian gas reserves are in the Nile Delta area and in the Mediterranean.

subsidiary control center to the principal control center.

Conceived by the Ministry of Petroleum, NATA covers a system that includes 150 gas production sites and delivery points and 4,700 km of pipelines with a transmission and distribution capacity of 135 million standard cubic feet per day (MMscfd).



Gasco's On Line Inspection technology is another part of the diverse effort that maintains the reliability of the gas grid. The technology recently was used to rehabilitate Egypt's oldest natural gas pipeline.

First installed in 1975 to move gas from the Abu Madi field to a power plant and fertilizer plant at Talkha, the 12-in. 40-km line was not properly coated when installed and large sections had corroded.

Reducing the operating pressure from 70 to 40 bar (atmospheres) would reduce capacity by 65%. Instead a rehab plan was devised to deal with more than 700 defects and faults ranging from superficial to dangerous and return the line to safe operation at 70 bar.

The rehabilitation plan called for the pipe surface at seven sites to be sandblasted, cleaned and recoated. For other defects, the pipe wall was reinforced without shutting down the pipeline system. A patch was welded into the line to repair 16 other defects, again without the need to shut down the line. But to repair some very severe flaws, the line had to be shut down and sections of pipe replaced.

Key international gas partners

In addition to LNG, BG Group's activities in Egypt span the gas chain from exploration, through development and production, including:

- Operatorship of two gas-producing areas offshore the Nile Delta, the Rosetta Concession and the West Delta Deep Marine (WDDM) Concession
- Production of 345 MMscfd of gas from the Rosetta concession for the domestic market
- Production of gas from the Scarab Saffron fields in WDDM, including 475 MMscfd for the domestic market, and 225 MMscfd for five years through the Damietta LNG plant
- Production of gas from the Simian Sienna fields in WDDM that supplies Idku LNG Train 1 with 565 MMscfd
- Development of the Sapphire field in WDDM to supply Idku LNG Train 2
- A major shareholding in the Idku LNG project
- A shareholding in the Nile Valley Gas Co., which has the distribution franchise for Upper Egypt

BG Group undertakes upstream development and production activities in Egypt through joint operating companies. In the case of Rosetta, this is the Rashid Petroleum Co. (Rashpetco); in the WDDM, it is the Burullus Gas Co. These companies are 50% owned by EGPC. BG Group and its partners in each concession hold the remaining 50%.

With its various partners, BP has, over the past few years, discovered 8 tcf of gas. All of the produced gas is sold into Egypt's domestic market. BP expects its aggressive exploration strategy to form the foundation for significant LNG business.

"With about 2 million household, commercial and industrial consumers now connected, the plan is to bring that total to 6 million consumers within the coming 6 years." Eng. Mr. Ismail H. Karara, Gasco Chairman

In early 2006, Egypt and Greece signed a memo of understanding for oil and gas exploration that also calls for discussing the best economic means to export gas to Greece either through LNG, CNG or pipelines. Greece would become a transit point in moving gas on to Europe. Formation of a joint work group made up of the two countries' experts will be the first phase of the cooperation.

Greece already has begun to study a plan to transfer CNG to the Greek islands of Crete and Rhodes in cooperation with Egypt. By the end of 2006, the natural gas pipeline between Turkey and Greece will be completed along with a study of a gas pipeline between Greece and Italy.

The two pipelines will enable gas movement from Italy to Turkey and it will play a major role in getting Egyptian natural gas to other new markets.

Building Egypt's downstream:

Master petrochemical plan, refinery expansion will make a world leader

Economic growth and growing populations will keep global demand for transportation fuels and petrochemical products growing at a brisk pace for the foreseeable future. Meeting that demand will require large investments in additional refining and manufacturing capacity.

To be competitive, that capacity should be located where it is convenient to both feedstock and markets. And it should be capable of producing the high quality, lighter products that world markets increasingly demand.

Egypt's significant petroleum resources—especially its gas reserves—and its strategic location make it an attractive place to invest in new capacity. The country's long term economic and political stability serve to reduce the risk of investment and add another measure of competitive advantage.

With these assets—and its technical expertise—Egypt has a unique opportunity to take a leadership position in meeting tomorrow's demand for high quality petroleum and petrochemical products.

To ensure that full advantage is taken of the potential that tomorrow's markets promise, the Government of Egypt and the Ministry of Petroleum have formulated plans and begun to take action to convert that opportunity into growth for Egypt and products for world markets.

Among those plans and actions are a world-class grassroots refinery, upgrades to existing refineries and a comprehensive petrochemical industry Master Plan.

Refining

As the world's spare refining capacity continues to shrink, Egypt's position as a venue for investment in the expansion of existing plants and new facilities becomes increasingly attractive.

Meeting the global need for more refining capacity will focus on sophisticated 'complex' capacity to produce the light sweet petroleum products that markets now demand. A more complex refinery also is able to produce more light transportation fuels from cheaper heavy oil, providing a competitive advantage when high crude prices combine with ever more stringent air quality regulations.

Kerosene storage tanks. Midor refinery produces LPG, 95 (RON) gasoline, jet fuel and diesel.

Last year, Egypt's refineries produced about 30.4 million tons of products. Domestic demand for petroleum products in fiscal year 2004/2005 was almost 26.5 million tons and is expected to exceed 27 million tons in the current fiscal year.

Also last year, EGPC began a program to upgrade the capacity of existing plants to 31.4 million metric tons annually, an increase of 1% from the previous year. The company also estimates capacity of existing refineries could be boosted further, perhaps to 35 million tons/year.

The upgrading plan will increase kerosene and jet fuel production by 5% over the previous year and gasoline output by 3%. Production of high value solvents will increase by 10%.

At end of the 2004/2005 year, a variety of upgrading projects were in progress under a detailed plan to maintain capacity, remove bottlenecks and fulfill health, safety and environmental requirements.

Key upgrading projects among Egypt's refineries included:

- Upgrading a lube oil complex to maintain efficiency and increase production
- Rehabilitation of furnaces to maintain production capacity
- Installing six boilers at three different plants to meet operating steam demands
- Replacing current solvents at three locations to increase lube oil production capacity and meet international specifications
- Building a hypochlorite sodium unit to treat and filter process water
- Installing a hydrogen compressor to meet hydrogen demands

Midor: State of the art

Among Egypt's nine refineries, the Middle East Oil Refinery (Midor) is one of the most important, said Mr. Nazeem.

Midor is a grass roots refinery with a design capacity of 100,000 barrels per stream day (b/sd) built around eight licensed units. With high conversion capability based on

Midor is a grass roots refinery with a design capacity of 100,000 barrels per stream day (b/sd) built around eight licensed units.

hydrocracking and delayed coking technologies, it is designed to produce LPG, 95 Research Octane Number (RON) gasoline, and jet fuel and diesel that meet Y2005 European specifications.

"Those products represent more than 85% "white" products recovery," said Mr. Nazeem.

Also under study is a capacity increase. "The refinery business has seen the strongest refining margins ever in the last two years and most forecasts indicate a continuation of this trend," said Mr. Nazeem. An ongoing study to evaluate the most economic expansion scheme indicates that throughput could easily be increased by 20%, he said.

"Among Egypt's 9 refineries, the Middle East Oil Refinery Midor is one of the most important."

Mr. Mahmoud Nazeem, Midor Chairman

In periods of high oil prices, hydroskimming refineries are the most adversely affected because they convert almost half of the crude barrel into fuel oil. For a complex refinery like Midor, however, crude oil price has much less impact. Rather, it is the ratio of products prices to feedstock (crude) prices that has the largest influence on refinery margin.

To remain competitive, refineries such as Midor must be constantly updated as new technology becomes available. Installation of an advanced process control system is being considered, and other investments in operating and management technology are under study.

"We are always keen to update the tools and software to ensure the best technology is being applied," said Mr. Nazeem.

Serving the global market

The lack of spare refining capacity has recently made it difficult to meet international product demand. But that market challenge is another opportunity for Egypt's refining industry, especially for Midor.

The refinery is fulfilling its share of internal demand, said Mr. Nazeem. LPG and diesel are the most crucial products required for domestic consumption and the refinery is dedicating all of its production of those two products to the local market. "Products for the local market meet a very strategic governmental requirement, and the products exported are the ones significantly increasing the value added to the crude processed through the refinery," said Mr. Nazeem.

The refinery is exporting all of its 95-octane motor gasoline and jet fuel production; product exports account for about 45% of the refinery's total production.

As far as feedstock goes, more heavy ends remain after distillation of heavier crude than is the case with lighter crude. But heavy crude is much cheaper than light crude. For a complex refinery like Midor, the ability to process heavy crude is an advantage because the bottom of the barrel can be converted to high value products.

"That's why we always try to maximize the heavy part of our crude diet as long as we remain within the refinery's design limits," said Mr. Nazeem. Midor is directly linked to the Sumed pipeline, giving the refinery access to a range of crudes.

Grassroots project

Also in response to the world's need for more refining capacity, Egypt's Ministry of Petroleum is considering a grassroots refinery that would be co-located with a major petrochemical complex and have a capacity of 200,000 to 300,000 b/d. The estimated total cost is about $9.5 billion.

According to Petroleum Minister Fahmy, the ambitious project now under study would produce high quality, clean burning transport fuels and petrochemical intermediates meeting the strictest European specifications.

"It is set to be one of the top 20 complexes in the world," he said.

The complex would include these main elements:

- A sophisticated refinery to produce high quality gas oil, unleaded gasoline, naphtha and kerosene
- Units to produce ethylene and polyethylene, propylene and polypropylene, styrene and aromatics

- A power and steam generation facility;
- Transportation and storage utilities.

This huge complex would offer about 100,000 job opportunities during its 5-year construction and implementation phases, according to Petroleum Minister Fahmy.

The Ministry of Petroleum plans to establish a private holding company to implement the complex, and make it a key element in the development of Egypt's downstream petroleum capability.

Also in response to growing demand, Ganope established a new petroleum products marketing company, Nile Petroleum Trading Co., which plans to build 25 integrated fuel and services stations in the next five years along the new main roads that connect the Nile side with Oasis and Red Sea areas to support the development of Upper Egypt.

Since it was established to fuel the development of that region, Ganope has boosted the number of its LPG filling stations by 55% and increased its LPG distribution units by 31% to help meet increasing demand, said Eng. Akl, Ganope Chairman.

"An ambitious refinery project now under study would be one of the top 20 complexes in the world." Petroleum Minister Sameh Fahmy

"And studies for new refinery and petrochemical projects are ready to be implemented when warranted by new oil and gas discoveries in Upper Egypt." said Eng. Akl.

Construction expertise

"Petrojet has helped execute a number of large modern refineries, including the Assiut refinery and Midor," said Eng. Dahy.

Established in 1975 to handle the construction of oil, gas and petrochemicals related projects, over the past five years, it has extended its operations outside Egypt with a presence in Libya, Jordan, Sudan, Yemen and Saudi Arabia. New bases are planned in U.A.E. and Qatar.

Petrojet also has executed a number of large gas processing and gas liquefaction plants. It is currently building oil, gas, chemical and petrochemical plants, and has signed contracts recently in Saudi Arabia and Qatar. In petrochemicals, Petrojet currently has a significant role in three projects, one for propylene, one for linear alkyl benzene and a third for a fertilizer plant in Damietta.

Also expected are new LPG and LNG projects as well as new gas transmission pipelines throughout Egypt.

Petrojet also has specialized capabilities including the fabrication of equipment used in refineries, gas plants and industrial plants.

One of the main objectives of the Ministry of Petroleum is to endorse the role and involvement of national companies in national plan projects. "Our plans definitely match and complement the Ministry's plans," said Eng. Dahy.

Petrochemical manufacturing

The market for petrochemical products is closely tied to both economic and population trends. Those trends can be cyclical, and the cost of petrochemical feedstock can be even more volatile, making strategic plan that is complete, yet flexible a key to success.

Though feedstock also includes lighter crude oil products, natural gas is increasingly at the heart of the global petrochemical industry's ability to produce building blocks for everything from plastics to medicine to computers, and materials for products that span from surgical gloves to fertilizer to auto parts.

Petrochemistry has an essential role in offering future generations a more sustainable world through developing new technologies, new materials and new solutions to age-old world problems, according to the European Chemical Industry Council (Cefic).

Because petrochemistry underpins a host of other essential industries, it is an 'enabling' industry, according to Cefic. Since it drives innovation in industries such as healthcare, telecommunications, construction and transport, it is central to the pursuit of a sustainable society.

Like refiners, petrochemical producers must keep pace with changing—and increasing—regulatory requirements. For example, new European Union legislation requires industry to register all existing and future new substances with a new European Chemicals Agency. The Registration, Evaluation and Authorisation of Chemicals (REACH) legislation will take effect in mid 2007. About 30,000 existing substances must be registered within the first 11 years during the phase-in period.

The regulation will affect all substances produced or imported in quantities of 1 ton/year or more.

A long-term strategic plan

Egypt's petrochemical sector dates to the 1950s when its polyamide unit to produce Nylon-6 became one of the first such production units in world. In the 1970s, fertilizer began to be manufactured from natural gas.

Then over the next two decades, polyvinyl chloride (PVC), polyester, linear alkyl benzene, ethylene, polyethylene and polypropylene were added to Egypt's petrochemical product slate.

With the rapid growth of the country's natural gas reserves, a strategic location, and a fast-growing global demand for a wide range of petrochemicals, Egypt now has a special opportunity to take its petrochemical industry to the next level.

To fully exploit that opportunity, the Egyptian Government has crafted a strategic Master Plan to guide development of the country's petrochemical manufacturing industry. Implementation of the plan will cost an estimated $10 billion over 20 years and create 14 petrochemical complexes producing 15 million tons of products annually.

Though the plan is continuously updated to reflect changes in local and international markets, as now envisioned, it would involve an estimated 24 projects and 50 production units.

Almost 30 million sq m of land in seven areas has been designated for possible petrochemical projects in Alexandria, Beheira,

Petrochemistry has an essential role in offering future generations a more sustainable world.

Almost 30 million sq m of land in seven areas has been designated for possible petrochemical projects. Amonia/Urea Complex in Damietta.

Kafr El Sheikh, Dahkalia, Damietta, Ismailia and Suez. Sites feature access to roads, utilities and local labor and feedstock.

The National Petrochemicals Plan is one of the largest long term strategic development plans in Egypt.

Egypt's current production of polyethylene, polypropylene and polyvinyl chloride meets a portion of local demand and abundant feedstock will help the industry expand. After completing the Master Plan, the 15 million tons/year of petrochemical products expected to be produced will be worth $7 billion. Imports worth $3 billion will be displaced and exports worth $4 billion generated.

In developing its petrochemical industry, Egypt benefits from its location at the cross roads between three continents and its proximity to these markets. But with a population of more than 70 million, growing domestic demand also adds to the attractiveness of Egypt as a place to invest in petrochemical capacity.

Egypt has a bright petrochemical future for many of the same reasons it has opportunities in other segments of the petroleum industry. It offers:

A reliable infrastructure with constant expansion;

- Committed available feedstock at competitive prices throughout project life
- Stable political, economic and legal environments
- An Investment Encouragement Law that includes guarantees and incentives
- Logistical advantage due to its proximity to European, Arab and African markets
- Availability of specialized technical expertise with relatively low labor cost
- Growing market demand

Executing the plan

Egypt's petrochemicals development plan will be implemented through the Egyptian Petrochemicals Holding Co. (Echem).

LPG Tower.

"The goal in creating Echem in 2002 was to establish a strong entity capable of carrying out the petrochemical Master Plan, and encourage and promote investment in the petrochemical industry," said Petroleum Minister Fahmy.

In managing and marketing Egypt's emerging petrochemicals industry, special attention will be paid to development of the private sector with emphasis on joint ventures and mixed capital companies. Echem will promote the plan to local and international investors and assist and support those investors—technically, financially and commercially—in planning, building and operating projects.

"As it pursues its vision to become a major manufacturer and marketer of petrochemical products, Echem will develop a competitive industry based on local human and natural resources using state-of-the-art technology," said Ms. Moneim El Banna, Echem Chairperson.

Echem's mission to establish and promote an advanced petrochemical industry will maximize the value added to the country's petroleum resources and support the national economy, she said.

The Master Plan for Egypt's petrochemical industry calls for a disciplined approach to each project that involves two phases—project development and implementation.

Project development begins with an in-house feasibility study that looks at technology, markets, sites and feedstock. A budget is also outlined and the environmental impact of the project is assessed. This step involves identifying groups of products and selection of the best combination of products along the product chain. Project objectives are assessed and a preliminary technical/economic picture created.

During this phase, the project is promoted to potential investors and a memorandum of understanding (MOU) is executed.

During the implementation phase, a "bankable" feasibility study is conducted and

the sponsor group of investors, technology providers and financiers is formed. Front end studies proceed and major agreements are signed for feedstock, product sale, land and consulting services. An EPC contract is also signed and financing is closed. In this execution phase, an important goal is to apply innovative contracts and financing schemes.

Finally, during start up and operation, Echem will evaluate performance tests and support ongoing operations.

Selecting projects

Echem developed an investment methodology to be followed in selecting and prioritizing projects over the period of the Master Plan. The approach is based on models designed to attract foreign direct investment through equity participation by international organizations, or to provide financing through local and foreign institutions. The process involves:

- Detailed feasibility studies conducted by independent consultants to maximize safety of investment, generate credibility with interested parties and facilitate financing
- Providing appropriate project sites that are suitable for future expansion and are convenient to utilities, feedstock and export facilities
- Guaranteed feedstock at competitive prices and long-term off-take agreements to guarantee loan payback
- Providing diversified financing resources
- Participating as an equity partner
- Applying a profitable exit strategy

Echem also is focused on research and development, according to Ms. Moneim El Banna. That effort will develop a new technological base, provide easier implementation of foreign expertise and develop local technological capabilities. Among its R&D activities, Echem will design and operate pilot plants for research purposes.

Echem also plans a new headquarters to cope with the larger staff and workload that will be required by Master Plan projects. It has acquired four acres at New Cairo and hired Enppi and Petrojet to select the architectural design by competition and build the new headquarters.

Monitoring and development

Another of Echem's goals is to develop the performance of operating petrochemical companies including Egyptian Petroleum Co. (EPC), Sidi Kerir Petrochemicals (Sidpec), and the linear alkyd benzene (LAB) unit of Ameryia Petroleum Refining Co. (APRC).

EPC, established in 1987, produces petrochemical intermediates including PVC, caustic soda, and chlorine gas. During fiscal 2004/2005, it produced 66,000 tons of PVC and exported 27,000 tons of caustic soda. Echem implemented a bankable feasibility study to evaluate the expansion of EPC's PVC capacity to 240,000 tons/year.

The Sidpec ethylene and polyethylene plant went on stream in 2001 using local natural gas as feedstock. The first olefins producer in Egypt, it replaced ethylene imports that were required for EPC facilities.

"Echem aims to produce the petrochemical products needed to meet the growing regional and local demand, creating new job opportunities." Eng. Ms. Sanaa A. Moneim El Banna, Echem Chairperson

Echem acquired 20% of Sidpec from EGPC in May 2005.

APRC's linear alkyl benzene unit produces LAB for the detergents industry. The company's capacity of 50,000 tons/year meets about 75% of local demand. Periodic market surveys keep track of LAB demand that will be met with the new 100,000 tons/year facility now being built.

In 2004/2005, petrochemicals imports reached 1 million tons valued at $1 billion. Echem expects projects in Phase I of the Master Plan to provide about 3.5 million tons of petrochemicals annually for export that will be worth about $1.8 billion.

EPC produces petrochemical intermediates.

Nafta secondary product. Sidpec plant.

HSE: Top priority

The common thread running through all facets of the Master Plan and its implementation is a commitment to protecting the environment and safeguarding the health and safety of employees, contractors and other involved parties.

Because their diversified operations pose a range of environmental challenges to Echem companies, a top priority has been to develop policies and guidelines that lead to solutions. Echem's Environmental Management System (HSE-MS) is designed to meet the requirements of local laws and international standards, and to be able to adapt to regulatory changes and the needs of new projects.

Important HSE programs at Echem have trained specialists and liaison officers on change management, HSE-MS, internal audit and trained 90% of Echem's employees on in-house fire protection systems. The effort also has prepared all company disciplines for ISO certification and integrated HSE requirements and applications into new projects. The company also monitors the performance of operating companies with monthly visits and meetings.

In addition to completing the first revision of HSE-MS, it helped EPC and Sidpec obtain HSE international accreditation for ISO 14001 and OHSAS 18001.

Key projects

A number of petrochemical projects are in various stages of development in Egypt, with completion dates stretching to 2009. Together, the following projects represent a total investment of more than $4.3 billion:

- A methanol plant at Damietta to cost $650 million will produce 1,260,000 tons/year after it starts up in the fourth quarter of 2009
- Ammonia/urea will also be produced at Damietta in a 1.2 million tons/year, $800 million facility, also scheduled for startup in the fourth quarter 2009
- At Port Said, a $520 million facility to produce 350,000 tons/year of propylene and polypropylene will start up at mid 2008
- Polystyrene production at a $150 million plant set to start up in third quarter 2008 at Alexandria will be 200,000 tons/year
- Also at Alexandria, the EPC contract for a $450 million linear alkyl benzene plant with an output of 100,000 tons/year was awarded in December 2005
- A $70 million acrylic fiber plant completed in early 2006 at Alexandria is designed to produce 18,000 tons/year
- Polyvinyl chloride production at a $35 million plant at Alexandria that will start up in 2008 will be 150,000 tons/year

The Sidpec ethylene and polyethylene plant went on stream in 2001.

• After it starts up near the end of 2009, a $1.7 billion polyethylene plant at Coastal Road will be able to produce 750,000-1 million tons/year

In addition to the petrochemical projects now being developed, opportunities for technologies like methanol-to-olefins will also be explored, said Mr. Karara, Gasco Chairman. And a number of fertilizer plants are also possible.

"Obviously, there will be growing demand for gas and petrochemicals in the local markets, and we have to balance all our needs," he said.

Gas is becoming more and more important in feeding petrochemical projects. "All these projects depend on gas," said Eng. Eid, "in addition to our gas projects such as gas fractionation and gas liquefaction."

Ethylene, propylene leader

One of Egypt's most important petrochemical companies is Sidpec. Organized in 1997 under the country's law of investment, Sidpec's main products are ethylene and propylene.

It currently produces about 300,000 tons of ethylene and 225,000 tons of high and low density polyethylene annually. It also has two small plants to produce 50,000 tons of LPG per year and another that produces 10,000 tons of butane.

Sidpec cites several factors that are important to its success, including the availability of natural gas resources in Egypt and a location between Gasco and the Egyptian Power Co. that allows integration of utilities and logistics. It also relies on highly trained personnel and uses the latest technology to comply with environmental regulations.

Working with different providers of proven technology has also been important to Sidpec's success, according to Mr. Mohamed Nour El-Din, Chairman.

"Inovene technology for polyethylene was unknown in our area, but we started working with ABB Lummus and now our product 'Egyptene' is very well known, not only in Egypt but in more than 50 countries around the world," said Mr. Nour El-Din.

The Egyptene polymer portfolio includes linear low density polyethylene (LLDPE) and high density polyethylene (HDPE).

Sidpec also supplies LPG to sister company Gasco. And Sidpec provides about 40,000-45,000 tons/year to the EPC for use in the production of PVC. The remainder of Sidpec's LPG output is used in its plant for the production of polyethylene.

About half of Sidpec's 225,000 tons/year of polyethylene output is exported. Since the production allocated to domestic market does not fully meet demand, the company is considering an expansion that would make it capable of meeting all local demand while maintaining its export volumes.

"Continuing to produce the same volume for export is important in maintaining our reputation in the international market," said Mr. Nour El-Din. In addition to quantity, quality is of critical importance in acquiring and keeping export markets.

"It's very important because we export more than 50% of our products," he said.

"In addition to the petrochemical projects now being developed, opportunities for technologies like methanol-to-olefins will also be explored."

Eng. Mr. Ismail H. Karara, Gasco Chairman

"If we are not environment friendly, we won't be successful."

Beginning at home

Mr. Nour El-Din is also Chairman of a committee comprised of all the industrial companies located in Sidpec's area that deals with the benefits of the member companies and the surrounding environment.

For example, medical insurance and medical treatment are provided for the people in the area, an especially poor region. Funds are available for schooling and for social services. A medical and educational conference for children is also currently planned.

"We and all the companies in this committee are trying to improve the living conditions in the area," said Mr. Nour El-Din. "This committee is not only for the petroleum sector companies but for other companies as well."

Egypt's deepwater potential:

Deep offshore growth promises daunting challenges, but great rewards

Deep and ultra-deep waters around the world offer impressive potential as a source of oil and gas.

In a 2004 study of deep water petroleum potential, Wood Mackenzie Group concluded that total resources expected to be discovered in the world's deep waters total 260 billion bbl of oil equivalent (boe). About 50 billion bbl of crude and 28 billion bbl of gas equivalent have been discovered to date; yet-to-find reserves of about 180 billion boe include 114 billion bbl of oil and 68 billion bbl of gas equivalent.

In 2004, oil and gas production from deep water accounted for about 5% of the world's total, a share that is expected to reach 9% by 2010, according to Wood Mackenzie.

The challenges—technical and economic—are daunting. But the rewards are enormous. For one thing, the volume of oil or gas discovered by each deep water well is five times the reserves added by a similar well on shore or in shallow water, said the study.

An enviable position

Though still in the early stages of evaluating options and implementing plans, Egypt is poised to realize the potential of its deep water areas. Independent studies indicate gas production from deep offshore could play a major role in Egypt's petroleum and petrochemical future.

The Wood Mackenzie study estimated future exploration in the deep water of the Mediterranean will add 70 tcf of gas reserves and 3 billion bbl of oil reserves to Egypt's hydrocarbon storehouse. The study ranked Egypt's deep water gas potential second in the world after the US Gulf of Mexico. If 70 tcf is indeed added, Egypt would have 18% of international deep water gas reserves.

The country's exploration success coupled with the large size of discoveries promise to make the cost per equivalent barrel of its yet-to-be-discovered reserves among the lowest, said the study.

Offshore Rosetta Gas Field.

To conduct the deep water study, Wood Mackenzie analyzed the potential of about 110 deep water reservoirs (below 400 m) in 30 sedimentary basins and river deltas in 18 countries.

A recent example of the promise of Egypt's deep water regions is a discovery in the Mediterranean Deep Marine Area. Petroleum Minister Fahmy announced the discovery by Rashpetco in the West Delta Deep Marine (WDDM) concession 120 km offshore at a depth of 750 m. The well encountered natural gas zones as well as intervals containing large amounts of hydrocarbon liquids. Studies are underway to estimate reserves.

Just beginning

In addition to Egypt's current proved gas reserves of 67 tcf, the consensus of international companies and consultants is that undiscovered gas resource is between 80 and 120 tcf.

"We trust we have not explored the whole economic zone in the Mediterranean yet," said Mr. Karara. "And the extensive exploration campaign for deeper targets has not started in the Mediterranean."

Most of the production now coming from the Mediterranean is from shallow structures. But recent discoveries by British Petroleum in north Alexandria and by Italy's ENI in Port Fouad indicate deeper structures are present.

"It is evident that deeper structures will play an increasing role in future supply," said Mr. Karara. "This makes Egypt a very good place for exploration for the next two or three decades."

Future concessions will be for both onshore and offshore areas. But companies are particularly interested in offshore Mediterranean and onshore in the Nile Delta and northern parts of Sinai Peninsula, said Mr. Karara. Companies have already begun very aggressive exploration campaigns and are expected to continue despite the current challenge of securing the offshore rigs.

EGAS's current pipeline network puts it in good position to begin to handle new production. The network currently transports about 6,000 MMscfd from current EGPC concessions. "We expect EGAS to start production from new concessions in the very near future after drilling begins this year," said Mr. Karara.

With the expectation that much greater demand for deepwater facilities is on the horizon, Petrojet has begun to modify its platform designs and tool up its workshops to provide equipment for more severe operating conditions, according to Eng. Dahy, Chairman.

The conventional platforms that the company has been building are designed for water depths to 150 m. Last year the company fabricated and assembled a new record of 17,000 tons of offshore platforms in its Maadia yard in Alexandria. It has another yard at Zeit Bay north of Hurghada to serve Red Sea projects.

Offshore and sub sea capability

According to Eng. Eid, offshore projects—especially those in Mediterranean waters to 2,000 m—are the future of Egypt. Platforms

Offshore Abu Quir Field. Offshore projects—especially those in Mediterranean waters to 2,000 m—are the future of Egypt.

can be installed economically in water depths to 100 m, and from 100 to 600 m, sub sea completions are an option. But beyond 600 m, high gas pressures call for more advanced technologies.

"Enppi has a long history of international cooperation," said Eng. Eid. "During the last 30 years we have worked with almost every international company, depending on the project we were engaged in."

As offshore exploration and development in Egypt expand, so does the need for an expanding array of marine services.

Petroleum Marine Services (PMS), an EGPC company founded in 2001, has expanded its capabilities and grown from a domestic pipe-laying and platform installation contractor—work it has done since 1980 as part of EGPC—into a competitive player that can provide a diverse range of offshore, sub sea and marine services.

"We are specialized in all aspects of offshore construction and installation from the engineering phase to final installation and pre-commissioning," said a company official.

To comply with its vision to serve both local and international markets, PMS has been qualified by most of the international bodies whose certification is required for offshore work.

The first international PMS project, a successful job in Saudi Arabia, helped to establish the company's reputation for quality work and innovation. Its unique approach to the installation of the Duba unloading facilities project for Saudi Aramco received industry attention and the appreciation of the client.

"It was a key project for the image and future of the company," said a spokesman.

PMS is open to joint venture agreements with international companies to provide the needed technology and capacity to cope with new discoveries.

Diverse vessel fleet

PMS has a large fleet of marine vessels including two derrick lay barges, a derrick/hook up barge, two materials barges, two supply vessels, four tugs, three launches and a diving support vessel.

In mid 2004 PMS purchased the PMS Mayo, a dynamically positioned diving support vessel equipped for saturation diving in water depths to 300 m. With two diving bells and 16 divers working at same time, it can work around the clock. PMS Mayo is one of the largest such vessels in the world.

PMS also has expanded its ROV and geophysical survey businesses. And it is performing intervention work, an important service in Egypt today, and one that will be increasingly important as deep water development and production expand.

The company is working in the Scarab/Saffron and Simian/Saffair fields where water depths are about 1000 m. These operations use an ROV rather than saturation diving, but both can be supported by the dynamically positioned vessel.

A full service provider

Developing Egypt's undiscovered oil and gas reserves will require a broad range of technologies and services. Over more than two decades, Pico Energy has developed into a service leader, providing comprehensive upstream and downstream services and products.

At first, Pico operated under licenses, but added new services until now it works through strategic alliances with two major oilfield service companies, Halliburton Energy Services and Weatherford International. It also offers its own services and operates a machine shop. Pico Petroleum Services today is ISO certified and its workshops are American Petroleum Institute (API) approved.

"Deeper structures will play an increasing role in future supply. This makes Egypt a very good place for exploration for the next two or three decades." Petroleum Minister Sameh Fahmy

These alliances bring a number of benefits to Pico, including the ability to standardize its services to better serve its multinational customers.

"Technological transfers are very important to us," said Mr. Sherif Abdel Wadood, Managing Director of Pico Group. "Blending foreign technical know how, local knowledge and local content is essential."

An example of Pico's innovative approach is its risk sharing and payment terms that matched cash flow requirements for Centurion Energy's work in its El Manzala concession. And recently, it implemented a lump sum contract approach with Offshore Shukheir Oil Co. that allowed the operator to complete drilling ahead of schedule and reduce well costs.

On the way to Egypt's petroleum future:

Leverage location, encourage investment, reduce environmental impact

Its Ministry of Petroleum has built a strategy that gives Egypt control of its bright oil and gas future. And the country's unique assets-location, hydrocarbon resources, people, and expertise-make it an attractive place to invest.

As it becomes an increasingly important partner in the world's largest industry, Egypt's petroleum sector has a broad range of opportunities to add value to the country's resources and enhance the quality of life of its citizens.

Taking full advantage of these opportunities will require capital, expansion, innovation, and the help of international investors and partners. And it must all be done in the context of reducing the environmental impact of both petroleum production and consumption.

A key goal: Attract investment

The Ministry of Petroleum's restructuring of the oil sector will speed up the decision-making process and focus on growing activities in gas and petrochemicals, said Petroleum Minister Fahmy. These companies participate in joint venture partnerships with international oil companies.

As in the past, oil and gas still play an important role in the country's economy. With a well defined economic model for investment, about $10 billion of foreign direct investment was attracted in the past five years, compared with $5.6 billion during 1996-2000, and $3.5 billion during 1991-1995.

The Petroleum Ministry expects the country will attract approximately $20 billion of international and national investments over the coming five years, $16 billion of which will be foreign direct investment. The Ministry expects half of the foreign investment to be directed to upstream projects.

"The main thrust of our strategy is to increase petroleum products exports, reduce the investment burden on the state budget and attract more private and Arab international investments," said Petroleum Minister Fahmy.

Illuminated tower creates night scenes.

Ambitious plans for gas, petrochemicals

The world's growing preference for natural gas will drive much of Egypt's petroleum future. The country's reserves, its LNG experience, its petrochemical Master Plan, and its access to markets all combine to make it a significant force in the global gas business.

Proved and yet-to-be-discovered gas reserves together provide Egypt the potential to become one of the leading gas producers and exporters in the world, while also providing feedstock for a world class petrochemicals industry.

"And there still are excellent opportunities for exploration to add more gas reserves and increase production," said Mr. Ismail. "There will be a variety of new investment opportunities along the entire value chain."

"Echem's mandate is to deliver an ambitious 20-year investment plan involving new petrochemical projects valued at $10 billion," said Ms. Moneim El Banna.

Though the plan was prepared after an international market overview that considered many factors, it is important to remember that the plan is dynamic."Echem is the catalyst that will create many opportunities for serious and interested entities," she said.

Sumed: Prepared for growth

The petrochemical Master Plan and refining capacity expansion that the government is implementing will be closely related to the Sumed pipeline.

"We will build new pipelines with the capacities and lengths needed," said Eng. Gomaa. "The extensions depend mainly on the availability of new projects." Expansions are expected in the Suez area or in areas very close to Sidi Kerir.

"We look forward to being one of the most important suppliers of crude oil for new refineries," he said. Sumed now supplies the Midor refinery, and wants to supply new refineries, including the 350,000 b/d grassroots plant being considered for Kafr El Sheikh. Sumed management also is considering a product handling facility at Sidi Kerir terminal.

All of this is in addition to Sumed's storage role that makes it a crucial hub for crude oil in the Mediterranean.

Fundamental responsibilities

Resource utilization and business expansion are critical elements in economic growth. To ensure that growth has a positive impact on society and the lives of individual citizens, however, business goals must be balanced with social responsibilities.

While it does pose risks, the petroleum sector can be one of the most effective industries in bringing positive change to the lives of people in the communities in which it operates.

In Suez, for example, two large refineries provide many jobs and support social services. In Damietta and Beheira, LNG projects have generated new industries and companies, and made infrastructure development possible. And in Alexandria, a petroleum industry center, large projects and ongoing operations continue to lower unemployment and contribute to the development of adjacent areas.

"It's not only the industry's expansion that is important to us; the environment is also very important," said Mr. Nour El-Din. "Keeping the environment clean is a must."

And in the end, a company's success is determined by its people. Little progress can be made unless development of the health, skills, knowledge, responsibility and enthusiasm of employees is a top priority.

Egypt General Data & Economic Information

- **Official Name:** Arab Republic of Egypt
- **Capital:** Cairo
- **System of Government:** Multi-party Republic
- **President:** Hosni Mubarak (Since 1981)
- **Prime Minister:** Ahmed Nazif (Since 2004)
- **Languages:** The official language is Arabic which is spoken by the majority of the population, although other important minority languages include Coptic, Nubian and Berber.
- **Location & Geography:** Egypt is located in the north-eastern corner of Africa.
- **Climate:** The larger part of Egypt has a desert climate which is hot and arid. There are two seasons.
- **Land Area:** 384,344 sq mi (995,451 sq km); total area: 386,662 sq mi (1,001,450 sq km)
- **Population(2006 est.):** 78,887,007
- **Currency:** The official currency is the Egyptian Pound (EP).
- **GDP/PPP (2005 est.):** $339.2 billion; per capita $4,400.
- **Real Growth Rate:** 4.7% GDP Inflation: 4.3%. Unemployment: 10%
- **Industries:** textiles, food processing, tourism, petrochemicals, chemicals, pharmaceuticals, hydrocarbons, construction, cement, metals, light manufactures.
- **Natural Resources:** petroleum, natural gas, iron ore, phosphates, manganese, limestone, gypsum, talc, asbestos, lead, zinc.
- **Exports:** $14.33 billion f.o.b. (2005 est.): crude oil and petroleum products, cotton, textiles, metal products, chemicals.
- **Imports:** $24.1 billion f.o.b. (2005 est.): machinery and equipment, foodstuffs, chemicals, wood products, fuels.
- **Major Trading Partners:** Italy, U.S., Syria, Germany, Spain, France, China, UK, Saudi Arabia (2005).

Source: Altapedia, Governments on the www, Columbia Encyclopaedia

Energy Overview

Energy Minister: Sameh Fahmy (Minister of Petroleum)
Proven Oil Reserves (1/1/05E): 3.7 billion barrels
Oil Production (2004E): 698,000 barrels per day (bbl/d), of which 594,000 bbl/d is crude oil
Oil Consumption (2004E): 564,000 bbl/d
Net Oil Exports (2004E): 134,000 bbl/d
Crude Refining Capacity (1/1/05E): 726,250 bbl/d
Natural Gas Reserves (1/1/05E): 67.0 trillion cubic feet (Tcf) (based on data released by Egypt's Ministry of Petroleum)
Source: EIA - Country Analysis Briefs on Egypt.

Acknowledgements

We would like to thank the following people and organizations for their assistance, support and profound insight into the production of this endeavour. It was a great pleasure working on a project that has such a promising future. We thank all of the people for such a warm and hospitable welcome while we were in Egypt preparing the editorial. We look forward to next year's edition and we hope that the information has been valuable to our vast list of readers throughout the energy sector.

First and foremost we thank Ministry of Petroleum, the Honourable **Mr. Sameh Fahmy** whose energy vision has allowed such important communication of the sector to the international community.

The Undersecretary of the Minister, **Mr. Shamel Hamdy** and to the Head of the Central Dept. of the Ministry for Media **Mr. Hamdi Abdel Aziz.**

And of course a special thanks to **Gasco** and all the Public Companies without whose collaboration and interviews it would have been impossible to have the editorial base for the report.

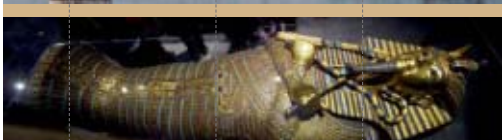
Special thanks to the Chairman of Gasco, Mr. Ismail H. Karara.

Sidpec
Special thanks to one of the emerging petrochemical companies and to its Chairman, Mr. Mohamed Nour El-Din.

Pico Energy Group
Special thanks to one of the most important and international private groups of Egypt. The statements of its Managing Director, Mr. Sherif Abdel Wadood have been extremely enriching for the editorial.

EGYPTIAN MINISTRY OF PETROLEUM

Egyptian Natural Gas Co.
GASCO



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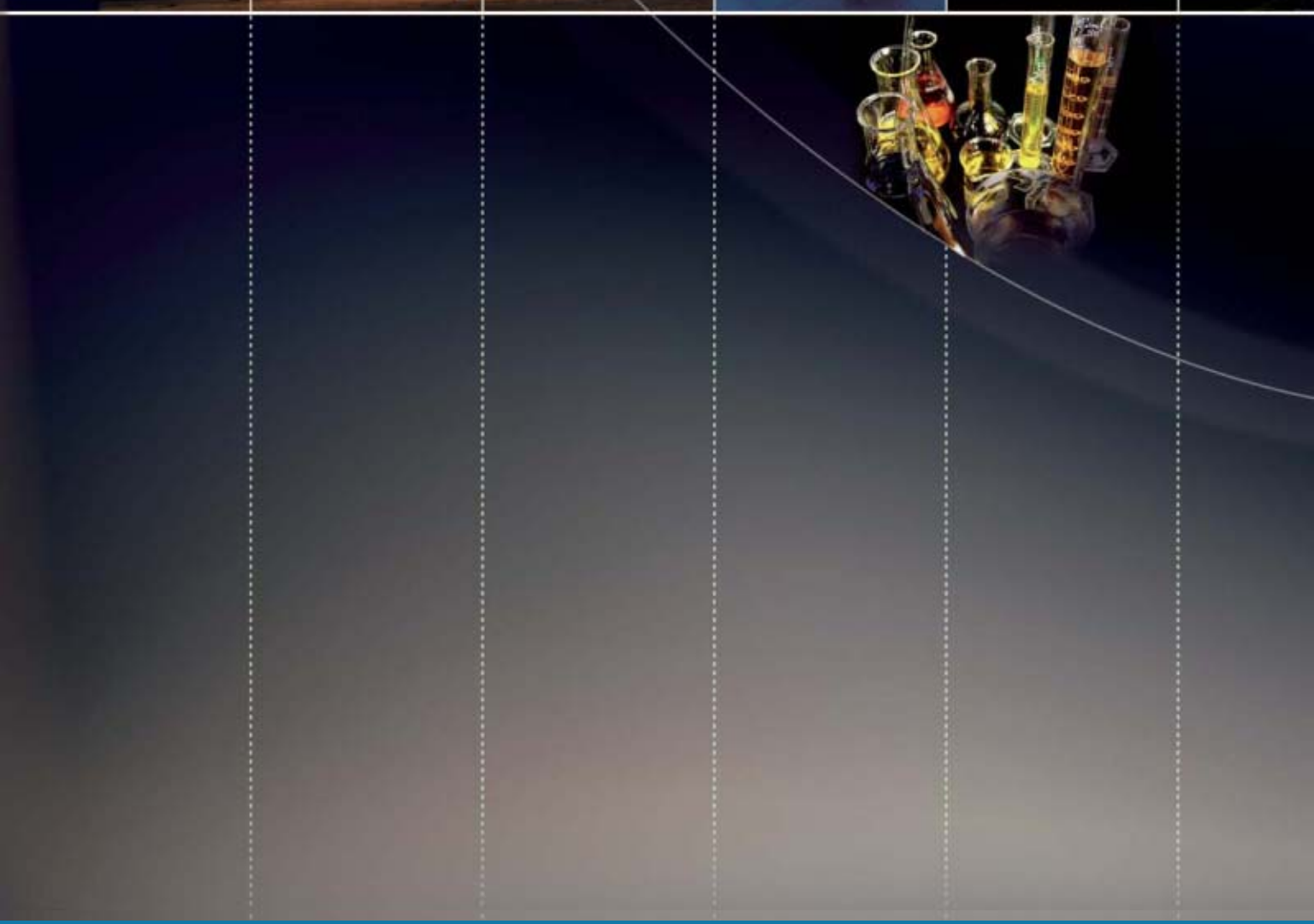
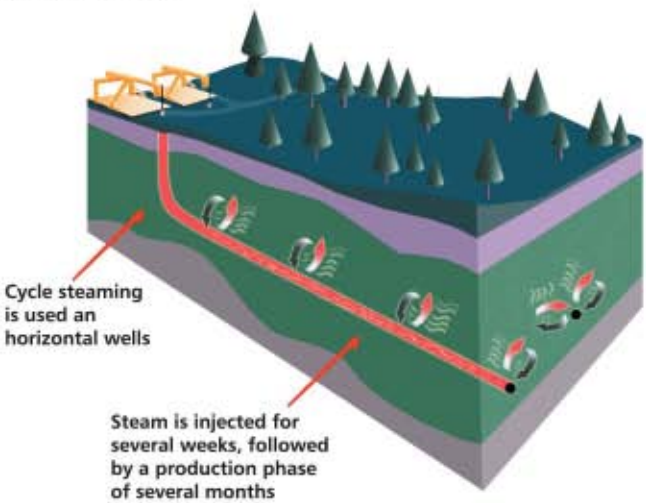


ANNULUS VAPOR RECOVERY MULTIPHASE BOOSTING

Canada's heavy oil reserves, estimated a 1.7 to 2.5 trillion bbl of oil in place, are an increasingly important source of supply, in part because technology advances have significantly reduced production costs and increased recovery. Bornemann multiphase boosting systems have been used successfully to help meet these goals by collecting gas from the wellbore annulus to reduce back pressure and provide additional revenue.

Steam injection processes are used as both primary and secondary recovery methods for heavy oil deposits around the world.

The most common methods are steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Both processes subject equipment to high temperatures, acid gases and steam.



Steam injection in horizontal wells.

Application Challenges

The cyclic steam, or "huff and puff", stimulation process requires only one wellbore. Each cycle consists of two phases. Steam is first injected for several weeks to heat the oil. Then during the production phase, the oil will flow into the wellbore where it is lifted to the surface, typically with beam pumping units.

Another injection cycle is begun when reservoir cooling causes production to fall below an acceptable level.

Steam assisted gravity drainage requires two horizontal wellbores spaced closely in the reservoir. Steam is injected continuously into the upper wellbore, mobilizing the oil to drain to the lower wellbore where it is pumped to the surface. A typical well stream includes saturated steam and condensed water; small amounts of bitumen; and gas, including methane, CO_2 and H_2S.

When multiphase boosting is used to collect wet gas from the casing annulus:

- Gas composition can shift from an 80/20 CO_2/methane ratio to a ratio of 20/80
- Inlet temperature is near that of saturated steam, about 130 °C
- 20-30 wells are drilled from a single pad, and total gas production from the pad may reach 30,000 sm^3/d (1 MMscf/d)
- A multiphase boosting can also be used to transfer total production from the pad

Imperial Oil Resources, Canada.

Design of a multiphase boosting for a well stream with an average gas volume fraction of more than 98 % and few liquid slugs-essentially a "wet gas compressor"-is

Bornemann

similar to the design for other multiphase boosting applications. However, the ability to handle thermal expansion and quick temperature changes is especially important for wet gas compression service.

A twin screw multiphase compressor/boosting has two pairs of meshing screws that rotate within a housing, forming cavities between them and between the screws and the housing. Fluid is conveyed from inlet to discharge along both sides of the housing, ensuring that axial forces are always fully balanced.

Because there is no metal-to-metal contact, the pump clearances are sealed by liquid. When handling a gas stream that contains little liquid, sealing and cooling liquid is stored in the pump housing and flows through a separate cooling circuit.

Multiphase boosting system.

Advantages

Bornemann multiphase boosting offer these advantages in annulus vapor recovery service:

- Simple, compact installation reduces foot print and environmental impact
- Control of annulus gas pressure and the height of the liquid column in the casing optimizes production
- Gas that was once wasted can be used or sold, lowering cost per barrel
- Greater than 99 % up time ensures constant peak production
- Low maintenance costs improve operating margins
- Elimination of flares helps meet obligations under the Kyoto protocol and local air quality standards

Design Features

These features of Bornemann multiphase boosting make them well suited for annulus vapor recovery:

- Seals operate at suction pressure
- A thermo-siphon circulates atmospheric buffer fluid for seal protection at high gas volume fractions
- Alloy overlay in O-ring areas mitigates CO_2 corrosion
- Speed of the variable frequency drive is controlled by suction pressure

References

Bornemann, with the ability to provide complete turnkey systems, has the world's longest list of multiphase boosting applications in thermal recovery, including:

- Systems installed at Imperial Oil Canada's Cold lake facility
- Systems installed in Canadian Natural Resources Ltd.'s Primrose field
- Four systems installed for Deer Creek Energy

Multiphase boosting, CNRL, Canada.

For additional information please contact
multiphase-info@bornemann.com

Joh. Heinr. Bornemann GmbH • Industriestr. 2 • 31683 Obernkirchen • Germany
Fon +49 5724 390-0 • Fax +49 5724 390290 • info@bornemann.com • www.bornemann.com

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Market Focus

New Developments in Seismic Technology

Supplement to Oil & Gas Journal

PennWell

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Tel 918.835.3161 / Fax 918.832.9290
www.ogjonline.com

PennWell, Houston office
1700 West Loop South, Suite 1000, Houston, TX 77027
Tel 713.621.9720 / Fax 713.963.6285

Managing Editor Bob Williams bobw@pennwell.com
Art Director Alana Herron, alanah@pennwell.com
Production Manager Katie Blair, katieb@pennwell.com

Petroleum Group President Michael Silber, michaels@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com

— Sales —

Houston
Regional Sales Manager, **Marlene Breedlove**, Tel 713.963.6293, Fax 713.963.6228, E-mail marleneb@pennwell.com

Southwest, Western States
Regional Sales Manager, **Marlene Breedlove**, Tel 713.963.6293, Fax 713.963.6228, E-mail marleneb@pennwell.com

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Scandinavia, The Netherlands, Middle East, Africa, UK
David Betham-Rogers, E-mail davidbr@pennwell.com, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France, Tel 33.2.33.282584, Fax 33.2.33.274491

France, Belgium, Spain, Portugal, Southern Switzerland, Monoco
Daniel Bernard, E-mail danielb@pennwell.com, 8 allee des Herons, 78400 Chatou, France, Tel 33.0.1.3071.1224, Fax 33.0.1.3071.1119

Germany, Austria, Denmark, Northern Switzerland, Eastern Europe, Russia, Former Soviet Union
Wilhelm F. Sicking, Verlagsburo Sicking, Emmastrasse 44, 45130, Essen, Germany, Tel 49.0201.77.98.61, Fax 49.0201.781.741, E-mail wilhelms@pennwell.com

Tokyo
Manami Konishi, e. x. press Co., Ltd., Hirakawacho TEC Building, 2-11-11, Hirakawa-cho, Chiyoda-ku, Tokyo 102-0093, Japan, Tel 81.3.3556.1575, Fax 81.3.3556.1576, E-mail manami.konishi@ex-press.jp

Brazil
Jean-Paul Prates and **Bernardo Grunewald**, Directors, Grupo Expetro/Smartpetro, Ave. Erasmo Braga 227, 10th and 11th floors Rio de Janeiro RJ 20024-900, Brazil, Tel 55.21.3084.5384, Fax 55.21.2533.4593, E-mail www.pennwell.com.br, Web http://www.pennwell.com.br

Singapore, Australia, Asia-Pacific
19 Tanglin Road #09-07, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel 65.6.737.2356, Fax 65.6.734.0655, E-mail yfyee@singnet.com.sg

India
Mr. Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India, Tel +91.11.6283018/19, Fax +91.11.6228928, E-mail rajan@interadsindia.com

Italy
Jean-Pierre Bruel, sas di Jean-Pierre Bruel, Via Trieste 17-22066, Mariano Commense (Co), Italy; Tel 39.031.751494, Fax 39.031.751482, E-mail medias@pcbrianza.net

OIL&GAS JOURNAL

Market Focus

NEW DEVELOPMENTS IN SEISMIC TECHNOLOGY

Supplement to Oil & Gas Journal

The breadth of seismic industry operations is suggested by these photos. Starting from center and moving clockwise: A CGG land crew works in desert terrain; a PGS land crew member checks his bearings on a portable GPS device; PGS staff review visualized seismic data; WesternGeco's Geco Topaz seismic vessel performs a 4D survey to monitor production in a congested offshore oil field; and a PGS land crew conducts a survey in Alaska. CGG photo courtesy of Cie. Générale de Géophysique, Paris. PGS photos courtesy of Petroleum Geo-Services ASA, Oslo. WesternGeco photo courtesy of Schlumberger Ltd.'s WesternGeco unit, London.

Advancing seismic technology key to oil and gas industry future

The oil and natural gas industry places a high priority on advancing the frontier of seismic technology.

The rationale is simple: No other technology development in the industry's recent history has had the kind of impact on finding and delineating new reserves that 3D seismic has.

So the quest continues for the next "magic bullet" in seismic technology.

At the same time, researchers persist in making incremental advances in existing seismic science, leveraging promising new technologies or optimizing traditional ones.

But pursuit of these quests comes against the backdrop of profound change within the industry.

Since the oil price bust of 1986, major oil companies have all but abandoned investment in research and development. That role has fallen largely to service companies.

In the intervening years, the seismic services industry has shrunk dramatically through consolidation. The number of full-service geophysical vendors has fallen by about 70% in the past decade.

The number of active seismic crews has plunged in parallel with that trend. From a peak of 744 at one point in 1981, the US seismic crew count fell to a record low of 37 at a point in 2003. While drilling activity has rebounded in response to higher oil and gas prices—with the US active rig count climbing to an average of almost 1,600 for first half 2006, up from about 1,300 the same time a year ago—the US seismic crew count has remained somewhat moribund, hovering in the 50s the past 2 years.

The seismic industry also must contend with a constantly shifting business model. For years, seismic applications focused on oil and gas exploration. As costs have fallen sharply and computing power and processing capabilities have multiplied exponentially, seismic contractors have found their business shifting more toward reservoir characterization. This trend dovetailed with operators' shrinking pool of prospect opportunities—created largely by political barriers—and with their Wall Street-influenced growing focus on adding reserves through acquisition and production optimization.

Recently, however, high commodity prices in tandem with declining reserve replacement rates have led operating companies to rethink their own business models. It isn't that the seismic-business pendulum is swinging entirely back to an exploration focus. It's that operating companies today must embrace seismic applications to both find and produce more oil and gas in areas with increasingly hostile environments and more challenging subsurface geology.

Seismic service companies are recovering from the doldrums of the past 2 decades as demand for their services has rebounded. Yet they continue to grapple with pressure from operating companies to keep a lid on costs as they strive to market their services as increasingly important in reducing risk throughout the exploration and production spectrum.

Goal: quality plus cost

All of the geophysical industry experts interviewed for this supplement agreed that the primary shared goal for both operator and contractor is to improve industry's ability to produce a clearer image of the subsurface in a cost-effective, environmentally sound way.

And they agree that the key to achieving that goal is new technology.

Mike Bahorich, Apache Corp. executive vice-president for exploration and production technology, sees three core cost-related aspects of seismic operations as the principal business drivers in advancing seismic technology.

"Quality, cost, and cycle time continue to propel seismic technology advances," he says. "These three are very much related, as an innovation that cuts cycle time allows more to be accomplished per day, resulting in fewer hours and lower operating cost.

"As more seismic traces are acquired or processed, qual-

"Humans do not always embrace change. As busy as we are today, it is not easy to take the time to learn something new in order to increase productivity. Sharpening the saw needs to be done from time to time, and there are plenty of new technologies coming down the pike that will make our industry more productive."

—Mike Bahorich, Apache Corp. executive vice-president for exploration and production technology

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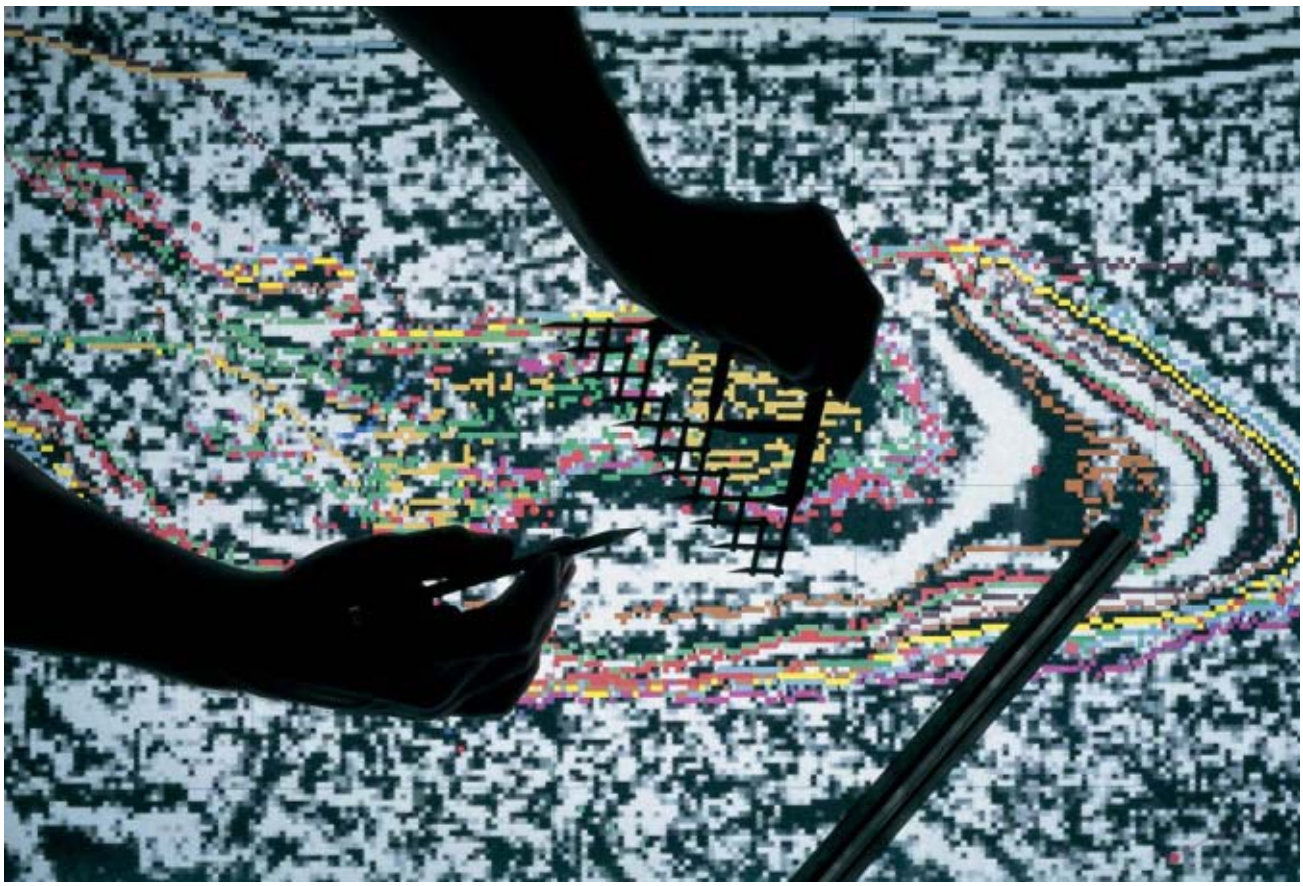

The human element is the most critical one in advancing seismic technology today—whether it entails coping with the "brain drain" of recruiting and retaining geoscientists or motivating them to generate the ideas that advance that technology. This image of a geoscientist interpreting seismic data is courtesy of Petroleum Geo-Services ASA, Oslo.

ity tends to improve. The largest financial benefit to operating companies generally occurs when quality takes a leap forward, allowing geoscientists to see and exploit what was previously undetected."

> "Today, the biggest issue is finding the right people. You have to have the ability to identify the right people, to recruit them, and to retain them."
>
> —*Thierry Pilenko, CEO and chairman of Veritas DGC Inc., Houston.*

Bahorich notes that as significant innovations surface and are utilized by the seismic industry, costs will come down.

"For example, innovations in large-volume flash memory chips have caused them to drop in price so dramatically that they are now cost-effective to separately record individual seismic traces in the field," he says. "This enabling technology allows the manufacture of independent, cableless, single-channel recording systems that are easily scalable to very large channel counts—critical for high-resolution imaging."

Bahorich also notes the innovations in parallel computing that continue to drive down prestack depth migration costs, allowing this technology to become available to more projects.

But the biggest barrier to advancing seismic technology is not a cost or technology issue, but a human one, according to Bahorich, a former president of the Society of Exploration Geophysicists: "Humans do not always embrace change. As busy as we are today, it is not easy to take the time to learn something new in order to increase productivity.

"Sharpening the saw needs to be done from time to time, and there are plenty of new technologies coming down the pike that will make our industry more productive."

Personnel issues

Another critical human issue in the seismic industry—one critical to the advance of technology as well as to the future health of seismic contractors—is fending off the "brain drain"

that continues to afflict all of the petroleum industry.

"Today, the biggest issue is finding the right people," says Thierry Pilenko, CEO and chairman of Veritas DGC Inc., Houston. "You have to have the ability to identify the right people, to recruit them, and to retain them."

He contends that Veritas has been lucky because over the years it has emphasized overinvestment in staffing. In particular, the company found good recruiting opportunities during the megamergers of the 1990s, when widespread layoffs resulted in a substantial pool of quality staff becoming available.

Pilenko also points to Veritas efforts to recruit geoscientists from "unconventional" sources.

"Sometimes, you have to stretch yourself" to attract quality personnel," he notes. "We have had excellent results recruiting from such places as China, India, Eastern Europe."

In the final analysis, while advancing seismic technology is the key to the oil and gas industry's future, proper nurturing of the human element will be what turns that key.]

Debate revived on seismic technology focus on exploration vs. production

The focus of the seismic business has undergone a seismic shift of its own.

For decades, seismic has been primarily a tool for exploration and development of oil and natural gas.

As seismic resolution improved and costs came down, industry saw increasing opportunity for optimizing production in a cost-effective way.

This trend accompanied the operating companies' own shifting focus in a low commodity-price environment to acquire existing reserves and expand reserves in mature producing areas rather than emphasize high-risk wildcatting.

"In order to keep pace with the ever-increasing demand [for oil and gas], we must continue to find new reserves and focus on developing seismic technologies for exploration and development."

—Robert Peebler, president and CEO of Input/Output Inc.

But an unexpected surge in demand coupled with the global oil production capacity surplus shrinking to a sliver has spiked oil prices to record levels and left the world worrying about future supply. The slow creep of reserves growth alone, it seems, will not suffice to feed tomorrow's demand. Much more exploration is needed.

With the current consensus for high oil and gas prices to continue for the foreseeable future and the inherent technical and economic limits to reserves growth and acquisition, two linked questions arise: Should the focus of advancing seismic technology shift back to exploration? Or should the emerging emphasis on production optimization continue to grow?

The answer, according to industry experts interviewed for this supplement, seems to be: Yes to both.

Production-oriented seismic

The Society of Exploration Geophysicists was given a name appropriate for the resolution of seismic tools when the association was formed in the 1930s, according to Mike Bahorich, executive vice-president for exploration and production technology, Apache Corp., Houston.

"It would have been difficult at the time to predict that seismic resolution would improve from the single record used to find large anticlines to the 4D images we have today that reveal subtle movement of fluids," he says. "Perhaps we still do not expect what the future holds."

Bahorich contends that, given the level of resolution achievable with seismic today, many investments in exploration research and development apply to production and vice versa.

"As our industry continues to mature, a greater majority of new reserves will be found in and around existing fields. As an example, less than one fourth of new reserves booked in the US from 1994 to 2004 were from new field discoveries," he says.

Even the biggest oil exploration target is dwarfed by the aggregate volume of oil left behind pipe: As much as 60-70% of oil typically remains unproduced in field development.

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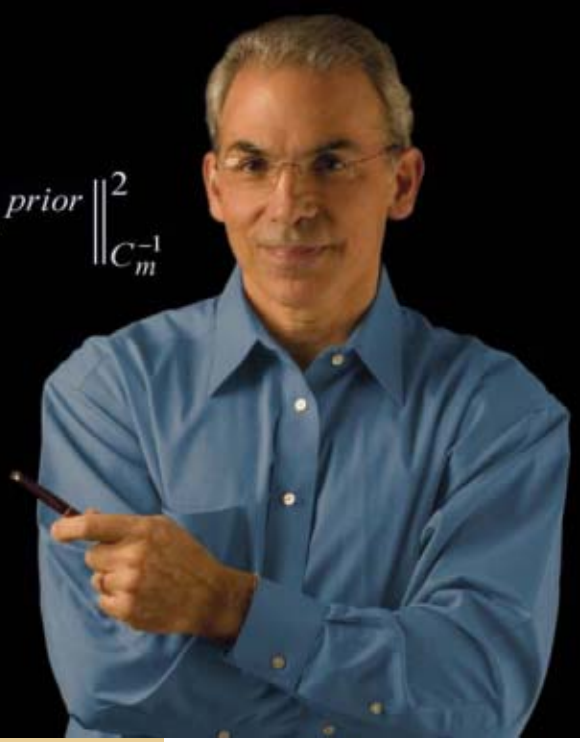

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e. All of the above
f. None of the above

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Accordingly, Bahorich sees the focus of seismic technology R&D gradually shifting towards production applications, "as this is where the greatest number of applications will be."

One area that Halliburton's Landmark unit sees as a growing opportunity for seismic applications is enhanced oil recovery (EOR) projects, says Doug Meikle, vice-president, Landmark and project management, Halliburton Drilling, Evaluation, and Digital Solutions.

"Sustained high oil prices due to relentless global demand and diminishing new field discoveries are making previously uneconomic or marginally economic opportunities much more attractive," Meikle says. "Experts believe there is a large amount of original oil in place that has not been produced. What's more, we already know where to find it."

Proliferation of EOR projects represents a growing opportunity for seismic applications: "Sustained high oil prices due to relentless global demand and diminishing new field discoveries are making previously uneconomic or marginally economic opportunities much more attractive. Experts believe there is a large amount of original oil in place that has not been produced. What's more, we already know where to find it."

—Doug Meikle, vice-president, Landmark and project management, Halliburton Drilling, Evaluation, and Digital Solutions.

Exploration-oriented seismic

No one foresees a production technology capable of boosting recovery rates exponentially.

And higher oil and gas prices mean mounting costs of acquiring reserves.

So the pendulum is swinging, to some extent, back to exploration seismic.

While seismic technology has been shown to increase recovery factors of existing reservoirs by 5-10 percentage points, notes Robert Peebler, president and CEO of Input/Output Inc., Houston, "in order to keep pace with the ever-increasing demand [for oil and gas], we must continue to find new reserves and focus on developing seismic technologies for exploration and development."

Some of the cutting-edge advances in seismic technology may even open up a whole new paradigm in exploration geology.

One example is cited by Per Arild Reksnes, president, Geoscience & Engineering, PGS Marine Geophysical, a unit of Oslo-based Petroleum Geo-Services ASA (PGS): the use of seismic attributes in so-called "megasurveys," which some see as a key to new discoveries in mature areas.

In mature areas such as the North Sea, there is a growing urgency for operators to discover and develop satellite fields before the large-field infrastructure is forced to shut down as economic reserves deplete. Megasurveys merge huge datasets from a wide variety of field-specific 3D surveys into consistent 3D data to help improve understanding of depositional systems in a regional context.

PGS has developed megasurveys with as many as 130 3D datasets. Such efforts, says Reksnes, "enable industry to reveal geology in a new and exciting way.

"It gives industry the ability to understand regional geology that in a big way can help companies understand the migration of oil and the trapping of oil."

Emphasizing both approaches

Many in the industry contend that the synergies between exploration seismic and reservoir seismic warrant continued emphasis on both and not on one to the detriment of the other.

"They are both of equal priority to us," says Robert Brunck, president of Paris-based Cie. Générale de Géophysique. "They are at the core of the challenges faced by the oil and gas companies that are keen to improve or at least maintain the replacement rate of their reserves."

Successfully replacing reserves requires advanced seismic technology in exploration "to image more subtle targets that are smaller and deeper and in more complex geological environments, and hence [requires] sustained R&D efforts," Brunck says.

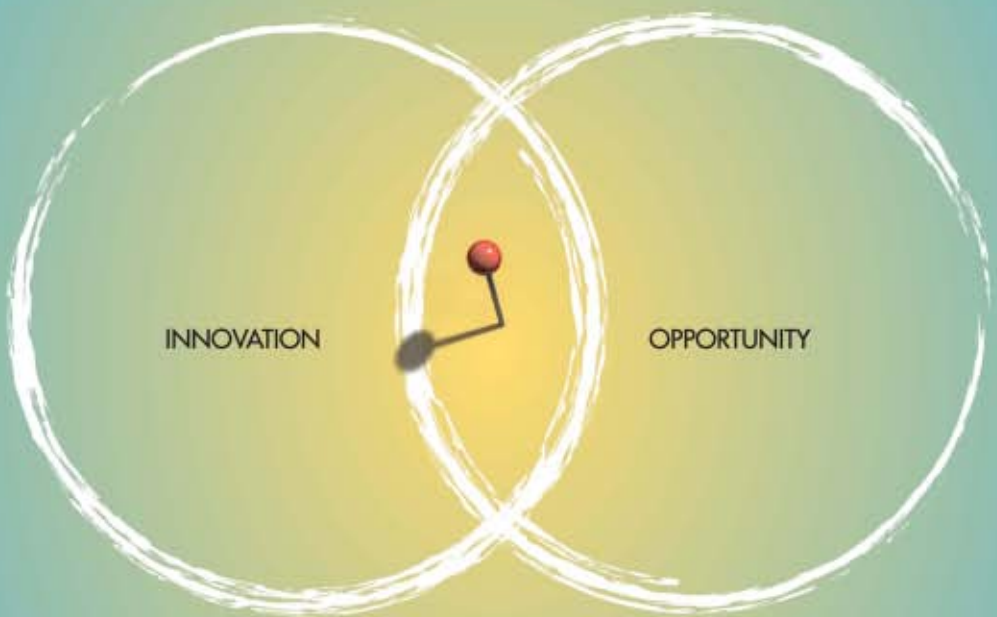
At the same time, he notes, "It is now widely accepted that production seismic, especially 4D and reservoir characterization, leads to an improvement [in oil and gas recovery rates] by monitoring fluid movements in the reservoir and identifying undrained zones.

"R&D efforts for production applications are also very challenging, notably because production targets test the limits of seismic resolution."

Noting the close links between exploration seismic and production seismic, Brunck adds that "pushing back the limits of seismic resolution for production applications will in turn also benefit exploration applications."

Perhaps the most appropriate model, according to Dalton Boutte, president of Schlumberger Ltd.'s London-based WesternGeco unit, is a more holistic approach.

"We see a dichotomy where conventional acquisition systems are being used for conventional exploration requirements, while advanced systems are required for high-risk



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exploration and production applications," he points out.

WesternGeco developed its Q suite of advanced seismic services and technologies "to deliver a 'seismic continuum' that spans the life of a reservoir, from providing the best exploration images to delivering quantitative rock and fluid properties for development and production," Boutte says. "The key to unlocking this potential lies in making fundamentally better measurements and in the ability to integrate seismic data with borehole readings."

It all really boils down to what the biggest driver in the seismic business is today, says Thierry Pilenko, CEO and chairman of Veritas DGC Inc., Houston: Reserves replacement ratio, whether through discovery or optimizing production.

Operators need to use seismic for better reservoir characterization in order to optimize production, he notes. They also need seismic to find new reserves.

"Seismic is applicable to both [exploration and production] domains," Pilenko says. "We should not consider them as two separate domains."

From a business standpoint, he notes "the main driver for volume seismic is exploration.

"But we have to have the flexibility to be able to apply seismic at the prospect level, at the reservoir level, and at the basin level. The real underlying issue is reserve replacement."]

Collaboration, cost reduction key to speeding take-up of new seismic technology

A key issue facing the petroleum industry in its efforts to find and produce more oil and natural gas is the slow take-up of new technology.

Nowhere is that more so the case than in the seismic business—a high-cost sector that nevertheless has yielded technology advances with greater impact than any other in the industry's recent history.

Seismic services contractors have undertaken the bulk of the field's technology research and development in the past 2 decades, watching their returns on investment in promising new technologies dissipate as operators remained reluctant to adopt them. That occurs despite the game-changing impact on operators' bottom lines in recent years of new technologies, such as 3D seismic.

Robert Brunck, president of Paris-based Cie. Générale de Géophysique (CGG), notes that industry has been inefficient in adopting new technology.

"How many years did it take for 3D technology to be widely commercially accepted after the first trial was made in the field in the '70s?" he asks. "It is certainly an area where a better-balanced risk sharing between operators and contractors could best advance seismic technology."

The critical question in advancing the threshold of seismic technology then becomes: What can be done to accelerate the take-up of new technology?

Industry reluctance

Seismic service companies describe operating companies' reluctance to readily adopt new technology as a risk aversion level that tracks oil and gas price cycles.

Per Arild Reksnes, president, Geoscience & Engineering, PGS Marine Geophysical, a unit of Oslo-based Petroleum Geo-Services ASA (PGS), notes that when oil and gas prices were lower, "companies had been more risk-averse, more reluctant to use a technology that normally demand field testing.

"At more than $100,000 a day, such long-term field testing pretty quickly gets very expensive," he says.

Reksnes sees an increasing eagerness among operators to try new technologies, however: "They see that new technology is needed as they deal with more and more demanding targets, more complex and deeper targets."

PGS Marine Geophysical Pres. Rune Eng thinks it incumbent upon contractors to demonstrate to operators that those companies with a more-embracing approach to common technology

A new eagerness is developing among operators to try new seismic technologies: "They see that new technology is needed as they deal with more and more demanding targets, more complex and deeper targets."

—Per Arild Reksnes, president, Geoscience & Engineering, PGS Marine Geophysical

> Accelerating the take-up of new seismic technology "simply comes down to the willingness of clients to better reward attempts at innovation."
>
> —*Paul van Riel, director, development and production, Fugro NV*

initiatives are those that have been the most successful.

"One of the things that we contractors need to show is that the companies that have had the most success recently are those that have invested in new technology," he says. "Unless you see a corporate drive behind it, you're not going to see that happen."

For Paul van Riel, director, development and production, Fugro NV, Leidschendam, the Netherlands, accelerating the take-up of new seismic technology "simply comes down to the willingness of clients to better reward attempts at innovation."

At the same time, however, it is important for the seismic contractor to understand the business model of the client, says Thierry Pilenko, chairman and CEO and Veritas DGC Inc., Houston.

"Our role is to help them minimize their risk," he says. "They need something that is an 'answer product.'"

At the same time, "we don't live from the oil that the seismic finds. This needs to be established.

"You have to have the ability on both ends to establish, on common ground, what you can extract from the seismic image that provides an answer product."

> "One of the things that we contractors need to show is that the companies that have had the most success recently are those that have invested in new technology. Unless you see a corporate drive behind it, you're not going to see that happen."
>
> —*Rune Eng, president, PGS Marine Geophysical*

Collaboration vital

Collaboration between E&P companies and service companies is vital to accelerating the adoption of promising seismic technologies, says Robert Peebler, president and CEO of Input/Output Inc., Houston.

"Equally important is the need for the industry to apply creative business and financial models that are able to couple technology innovations with immediate, real-world projects," he says. "To get seismic technology adopted rapidly, the application must also deliver on the three main points of the oil and gas companies, including improved image quality, reduced cycle time, and decreased operational costs."

Peebler contends that for collaboration between operating companies and seismic contractors to work effectively, however, E&P companies must be willing to take on more risk in adopting new technologies.

"This includes providing capital and assets, thought-partnering on technology development projects, and an 'E' attitude that says some programs may be 'dry.'"

Such collaboration could be leveraged according to an operating company's management philosophy.

"Many technologies are not utilized by asset teams because the benefits to their particular asset team do not outweigh the risks of trying something that may not work," says Mike Bahorich, executive vice-president, exploration and production technology, Apache Corp., Houston. "This does not mean that the benefits to the corporation are not far worth the investment, so it is often prudent to provide centralized funding to help mitigate risk at the asset team level."

Developing a close relationship with clients is critical to ensuring that seismic services contractors understand and correctly address their challenges, notes Dalton Boutte, president, Schlumberger Ltd.'s London-based WesternGeco unit.

"This relationship also provides an avenue to effectively apply new technology as it is developed and subsequently shorten the technology adoption cycle," he says.

Pilenko concurs, adding that Veritas makes it a point to deeply involve clients at every step in the development of new technology.

"It's important to close the loop in an interactive way," he says. "We need to embed our customers in our workflow and in our offices."

Such close collaboration underpins Veritas's business model, which is to focus on quality rather than on market share or size.

"If our market share increases, it is not because we've targeted market share, it's because we've targeted quality, and the customers became attracted to that emphasis on quality," he says. "This lets us work with customers who understand quality, and we can ask them, 'What do you want in the end?'"

Boutte acknowledges that operators have grown accustomed to seeing examples of technology, quite often in or near their fields, before making buying decisions.

"It becomes difficult with high-cost technology to put this burden entirely on the service sector," he says. "One possible

solution would be early publication of successes, which would require collaboration regarding show rights."

At the same time, it's important to listen closely to key customers and watch what they are doing with their technology investments, says Reksnes.

"PGS recently committed to a third-generation Ramform vessel [due for delivery in first quarter 2008] because the industry has clearly embraced the need for larger streamer counts," he points out. "The growth of the [multi-azimuth and wide-azimuth towed streamer] markets has not come about by the sole commitment of an individual service or oil company, it has come because all parties are increasingly recognizing the value of technological collaboration to solve the big challenges."

Reducing costs

Productivity is key to reducing costs in the seismic sector, particularly with regard to cable-based land recording systems, which can account for up to 20% of the operational cost of a typical onshore survey in North America, Peebler points out.

"In order to minimize the cost of land acquisition and reduce the footprint of seismic operations, we must move to embrace a new world of land acquisition without cables," he says. "By using cableless land acquisitions, we can improve operational productivity and leave a smaller impact on the environment.

Cableless land acquisition is seen as having the potential to significantly reduce land acquisition costs. An onshore seismic crew is shown laying out cables with sensors in the desert. Photo courtesy of Petroleum Geo-Services ASA.

"Additionally, the fact that many of these cableless systems also scale to very high station counts gives us the added benefit of being able to acquire fully sampled, higher-resolution data at the same time."

Of course, the technologies that introduce new efficiencies and improve productivity stand the best chance of getting adopted.

"History shows that any technology reduces in cost as it is embraced by the mainstream," says Reksnes. "New technology often requires massive investment, and such investment can never be maintained without a tangible return from consumers. Thus, natural selection has often erased countless innovations that initially appeared promising, but were never embraced by the mainstream.

"PGS has always pursued the 'big picture' in its engineering innovations—the things that really matter to the broader market, [such as] operational efficiency and flexibility, solutions that have a broad range of applications, and platforms that can have a reasonable shelf life.

"High-end acquisition solutions are only now being universally embraced—high-definition 3D, multi-azimuth, wide-azimuth towed streamer, etc.—and Ramform effortlessly accommodates them all whilst a raft of high-capacity newbuilds are being rushed into construction."

Brunck notes that CGG is gradually moving away from using standard 3D in the Middle East, thanks to its new EYE-D offering.

"We are reaping the benefit of the step-change in the performance of the latest generation of equipment and generating different sets of seismic data, with wider azimuth and higher fold, such as we have never been able to do before," he says. "And we are doing it for a marginal additional cost, using our patented High-Productivity Vibroseis Acquisition."

Boutte contends that cost becomes an issue if the value of the service or product is not apparent: "If the value exceeds the customer's expectation, then cost is not an issue."

In the final analysis, it is equally important to share ideas as well as risks, according to Bahorich.

"It is difficult to predict where the next breakthroughs will come from, but advances often come when bright people from different disciplines and perspectives come together and share information," he says. "As operators and contractors communicate more effectively, innovations will develop. "Sharing technology costs between operators and contractors enables ideas to flow more freely.

"Another benefit is that the contractor has a company ready to test and help refine the newly developed technology, which further reduces risk in research investments."

Some contractors see little scope for further reducing costs relative to seismic's value.

"Seismic is not expensive relative to the value its use creates for the clients," says Van Riel. "In fact, seismic is now—for many years in a row—seen as the most valuable E&P technology for the operators. So I doubt if lowering the cost would significantly expand applicability."

Pilenko concurs: "We are getting more into a new phase, where cost has become less important than innovation."]

Seismic technology advances accelerating to meet operators' E&P needs.

Exciting new developments in seismic technology are emerging to meet the needs of operators as they explore for oil and natural gas in more challenging environments and increasingly complex geology.

In addition, there is a growing emphasis on improved clarity of subsurface feature images as operators step up the use of seismic applications for production, notably enhanced oil recovery (EOR).

3-D seismic

While it has proven itself to be the most important technology in the oil and gas industry of the past 2 decades, the next step-change beyond 3D seismic may be at hand.

Full-wave acquisition and processing is revolutionizing seismic imaging, just as 3D seismic did 20 years ago, contends Robert Peebler, president and CEO of Input-Output Inc., Houston.

"Present geophysical assumptions inherent in conventional 3D imaging limit our ability to image reservoirs and understand their contained fluids well enough to have maximum economic impact," he says. "These are assumptions of isotropy, frequency band limits, vertical emergent angle, and the requirement for source-generated noise attenuation in the field.

"Because of these assumptions, 3D imaging as currently implemented has peaked in its usefulness and its ability to deliver additional benefit to the industry."

Robert Brunck, president of Paris-based Cie. Générale de Géophysique (CGG), sees more sophisticated wave equation migrations as necessary for dealing with geologically complex settings, such as the Gulf of Mexico's deepwater salt geometries and subsalt features: "These will accurately deal with all wave propagation phenomena in such complex settings. They are not only very computationally demanding but also require a much more accurate model of the subsurface to perform to their full potential."

Brunck sees the next key developments in wave equation migration as steep-dip and turning waves, while very fast and targeted, or beam, imaging algorithms will yield interactive velocity model building and structural model validation.

"TTI (tilted anisotropy) will become the anisotropy standard and move to azimuthal anisotropy with the advance of wide-azimuth acquisitions and more OBS (node) surveys," he adds.

One way of solving difficult offshore 3D imaging challenges such as subsalt and subbasalt are novel towing configurations, says Dalton Boutte, president, Schlumberger Ltd.'s London-based WesternGeco unit. These include over/under streamers and rich-azimuth shooting.

4D

What 3D has been to exploration, 4D seismic may prove to be for production.

Boutte contends that production will benefit greatly from further developments in 4D seismic, "as improved repeatability will enable more confident predictions of changes in fluid properties.

"Reductions in cycle time are making these measurements viable for active reservoir management. The advent of steerable streamers has provided our clients with the opportunity to treat every exploration project as a baseline 4D survey."

While some see 4D essentially as just an extension of 3D, Brunck contends that view is changing.

"The trend for denser acquisition with a closer receiver spacing results in an increase in data volume," he notes. "We also see a reduction in the period between successive vintages, as the detection of the 4D signal due to the oil production is highly related to the noise/repeatability level. Reducing the cycle time is a way to increase the signal quality, as is made possible by permanent installations.

"The challenge comes in the need to accommodate larger and more frequent data volumes and adapt from a static source

Production will benefit greatly from further developments in 4D seismic, "as improved repeatability will enable more confident predictions of changes in fluid properties. Reductions in cycle time are making these measurements viable for active reservoir management. The advent of steerable streamers has provided our clients with the opportunity to treat every exploration project as a baseline 4D survey."

—Dalton Boutte, president, WesternGeco

of information (a simple snapshot/difference of two vintages) to the dynamic problem of tracking the movement/evolution of the 4D signature," Brunck says. "The goal will be to replace the 4D difference with 4D predictability in a similar way to that used in weather forecasting."

As operators in mature offshore areas such as the North Sea and Gulf of Mexico review their global asset portfolios of producing assets for candidates for continuous 4D seismic to optimize recovery, such permanent monitoring will become increasingly common, says Per Arild Reksnes, president, Geoscience & Engineering, PGS Marine Geophysical, a unit of Petroleum Geo-Services ASA, Oslo.

"Permanent monitoring using fiber optic technology is a very exciting growth area that we expect to see take off soon," he says. "PGS has developed an entirely optical system that uses passive in-sea sensors and telemetry to record seismic data with high fidelity and dynamic range, in water depths as large as 3,000 m, and with low weight, great reliability, and improved costs per channel for deployment and operation.

"We are entering the commercialization phase and already are receiving a significant level of interest—often for applications that we had not previously considered."

Multicomponent seismic

The potential for obtaining the range of information available in the full-wave field through multicomponent seismic has yet to be realized.

Multicomponent seismic remains a marginal business for the seismic industry, notes Brunck. The reason: Industry still does not have a clear understanding of how shear waves propagate, due to their tendency in certain layers to suffer from dispersion, attenuation, or splitting.

Nevertheless, the CGG chief says his company continues to press research in multicomponent seismic, notably in building new algorithms based on wave equation and in developing a special workstation, Vector Vista, dedicated to analyzing and interpreting multicomponent data.

Such innovative processing techniques are needed to leverage the digital full-wave information obtained with advanced multicomponent receivers, says Peebler. Vector filtering removes source-generated noise recorded by single-point receivers, resulting in a higher-bandwidth P-wave signal.

"There also has been great progress in processing converted wave data both onshore and offshore, revealing subtle subsurface features," Peebler points out. "Longer-term research is focused on improving the utility and efficiency of processing and interpreting...multicomponent data, especially in complex acquisition environments such as the Arctic, desert, shallow-water, and ocean bottom, as well as when imaging fractured reservoirs."

Also helping the multicomponent cause are advances in digital sensor technology, notably the MEMS (microelectromechanical systems)-based accelerometers that provide sensing capabilities not seen with conventional geophones. These sensors can record ground accelerations with very low distortion and very high accuracy in magnitude and orientation, says Brunck: "It therefore becomes possible to record the full-wave field with much improved vector fidelity."

Borehole seismic

As acquisition hardware costs come down, industry is likely to make greater use of borehole seismic such as crosswell and vertical seismic profiling (VSP).

Brunck sees the development of larger tool arrays continuing, with CGG unit Sercel currently marketing a 32-level tool and expected to introduce a 100-level system in the near future.

"This push to longer arrays will stimulate the demand for 3D and 4D VSP, providing more resolution and certainty in VSP reservoir imaging," he says. "This in turn will allow better linkage between VSP and surface seismic datasets."

Furthering that effort will be advances in processing technology, notably in the area of imaging and migration, such as his firm's new vector migration algorithm that can migrate multicomponent data as a single dataset.

Boutte contends that seismic data will realize their potential as quantitative oil field measurements when they tie with borehole data without being forced.

"With calibrated inversion of Q seismic data, rock and fluid properties can be propagated throughout the reservoir model in conjunction with geostatistics," he says.

Massive channel counts

There is widespread consensus that industry is moving towards land seismic surveys with ever-larger numbers of channels, according to Brunck.

"If we look at the maximum channel count over the last 40 years, the trend is doubling every 3.5 years," he says.

That trend, Brunck adds, is driven both by increased productivity and by such factors as single-sensor, three-component

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>
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seismic, multi-azimuthal acquisition, and high receiver density, all in quest of a higher-quality image.

In the past 12 years alone, he notes, Sercel equipment has seen the weight per channel divided by 10 and power consumption by almost 3, while significantly increasing the data rate.

The channel-count records keep falling.

Boutte reports his firm's Q-Technology capability to record more than 20,000 channels per shot with a marine configuration of eight 8-km streamers and as many as 25,000 channels with its land crews.

Visualization

The maturation of 3D visualization has progressed beyond novelty status to that of an effective, high-performance tool.

Volume rendering and immersive visualization have become widely accepted in efforts to navigate large datasets, notes Brunck.

"These capabilities will be taken one step further with the use of distributed rendering on cluster nodes that will allow 3D volumetric rendering of ultralarge datasets (several terabytes) on very large display walls with unequaled performance and resolution," he predicts. "Combined with state-of-the-art compression and transfer technologies, this will allow these datasets to be efficiently visualized at remote locations even across low-bandwidth links."

Boutte stresses that visualization techniques must be fast, quick to load, and easy to use if the full benefits of seismic as a reservoir tool are to be realized: "The main developments will be in usability, attribute display, and computing speed."

Launched in summer 2006 was the Geo Challenger, the new flagship of Paris-based Cie. Générale de Géophysique's (CGG) seismic vessel fleet. The new 3D/4D HR seismic vessel is the first in the world to operate with Sercel Sentinel solid streamers and has a 12 towpoint capacity. Photo courtesy of CGG.

Computing

The primary driver in the progress of seismic technology in the past 2 decades has been the huge leaps in computing power. And there is more to come, say industry experts.

"Our well-known ability to manage massive computer capacities will continue to be at stake with faster chips, greater storage capacity, and faster networks—to accommodate increasingly computer-intensive algorithms and larger data volumes, both for batch and interactive applications," says Brunck.

One area where computing power growth will make a big difference is reverse time migration (RTM), which properly propagates wavefields through the most complex velocity regimes, including subsalt, for structures with >70° dips and in the presence of reflection boundaries that may generate internal multiples, says Peebler.

"Although RTM is not a new concept, its application has been limited due to lack of computational power needed to run the RTM algorithms cost-effectively and in a timely manner," he says.

Peebler cites his firm's efforts to improve RTM efficiency with its GX Technology, which it has begun to apply on several medium-sized commercial projects in the Gulf of Mexico.

Other advances

Thierry Pilenko, CEO and chairman of Veritas DGC Inc., Houston, cautions against overlooking the new ideas that might spring forth with new technology from data acquired with conventional seismic. One such example is applying wide-azimuth seismic to areas covered by vintage multiclient data, a trend Pilenko sees as accelerating in the near future, particularly in the North Sea and deepwater Gulf of Mexico.

"We think of multiclient data as a mine of information from which we can apply new ideas from the existing data and get a new product," he says. "People don't realize how much effort went into [developing the multiclient data libraries]. This is an area where seismic companies are not just delivering new products but building a knowledge base."

Among other technology areas advancing the science of seismic, Boutte would like to see successful and efficient integration of seismic data with electromagnetic data, which "promises to be a significant contributor to both exploration and development applications for seismic data."

Brunck contends the benefits of seismic technology to operators' risk reduction and decision-making efforts have been proven in E&D and now need to be leveraged further into production.

"Beyond the initial breakthroughs in 4D, we have to concentrate on integrating more systematically seismic information into the workflow of production data and close linkage with reservoir properties," he says. "This is within reach, given the very rapid evolution of the various technologies the seismic industry integrates for the E&P players."

And some advances may come from outside the seismic industry altogether, notes Mike Bahorich, executive vice-president, exploration and production technology, Apache Corp., Houston.

"Apache recently made a significant contribution to the M.D. Anderson Cancer Center [in Houston] to aid imaging research," he says. "Although this was predominantly a humanitarian gesture, advances in medical imaging may benefit our industry as well."]

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