Week of Aug. 13, 2007/US$10.00

PennWell

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com

Process Control Technology

STAR technology drives emissions down, profits up
More operators eye Maverick shale gas, tar sand potential
Petro-Canada updates Fort Hills oil sands costs
Waxy crude shutdown method yields savings

OIL&GAS JOURNAL®

Aug. 13, 2007
Volume 105.30

Process Control Technology

Regular Features

Cover

An operator checks a refinery's control system, which uses a Honeywell Experion R300 C Series I/O. Process control systems are becoming more important as refiners and petrochemical plant operators focus on them to improve operations. This issue's special report, Process Control Technology, begins on p. 54 with an article that discusses the advantages, disadvantages, and future developments in fieldbus. The second article, p. 62, covers the use of dynamic process control to review a plant's design and control systems. Photo from Honeywell Process Solutions.

OIL&GAS JOURNAL online research center

The full text of Oil & Gas Journal is available through OGJ Online, Oil & Gas Journal's internet-based energy information service, at http://www.ogjonline.com. For information, send an e-mail message to webmaster@ogjonline.com.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 48 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. $60, 2 yr. $85, 3 yr. $109; Latin America and Canada: 1 yr. $64, 2 yr. $100, 3 yr. $135; Russia and republics of the former USSR, 1 yr. 1,500 rubles; all other countries: 1 yr. $109, 2 yr. $175, 3 yr. $250, 1 yr. premium digital $59 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. 105, No. 30) 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

London

Tel +44 (0)208.880.0800
International Editor Uchenna Izundu, uchennai@pennwell.com

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

Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service

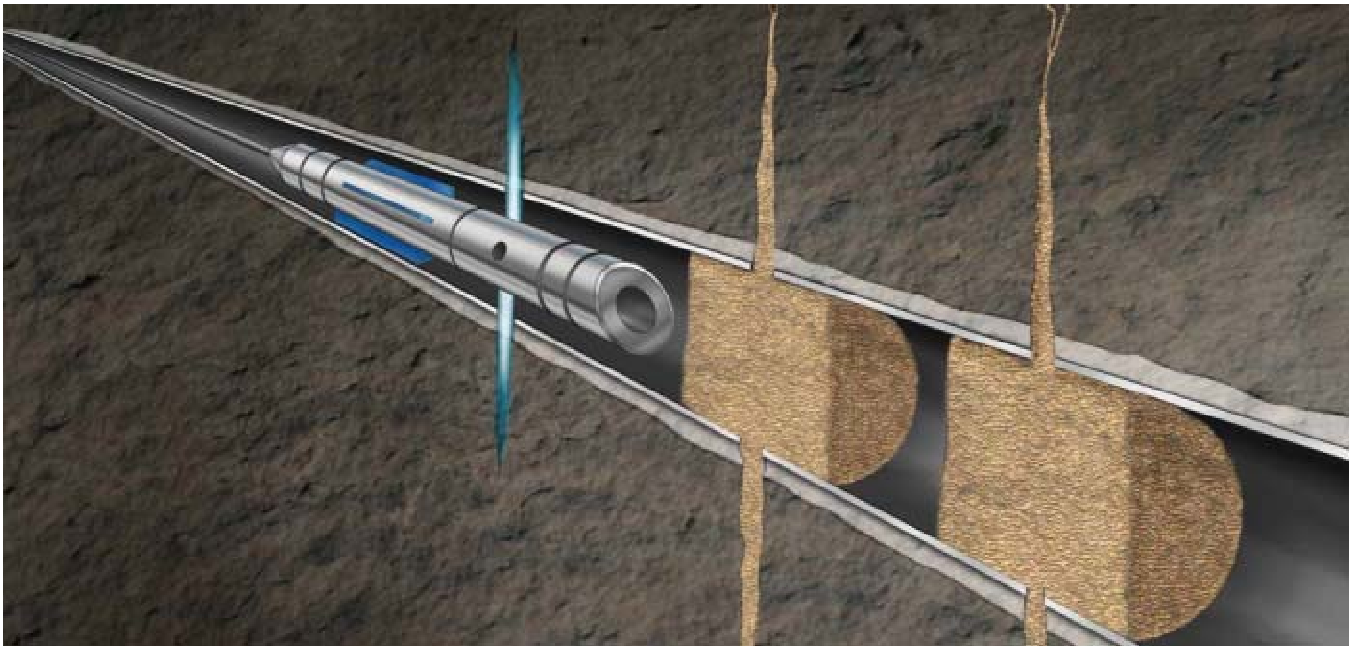
P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Circulation Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters

1421 S. Sheridan Rd., Tulsa, OK 74112

P.C. Lauinger, 1900-1988
Chairman Frank T. Lauinger
President/Chief Executive Officer Robert F. Biolchini

Member Audit Bureau of Circulations & American Business Media



OGJ Newsletter

Aug. 13, 2007

International news for oil and gas professionals
For up-to-the-minute news, visit www.ogjonline.com

General Interest — *Quick Takes*

Marathon unit to pay fine in oil-price case

Marathon Petroleum Co. LLC agreed to pay a $1 million civil fine to settle a US Commodity Futures Trading Commission charge that it tried to manipulate crude oil markets.

CFTC alleged that Marathon tried to manipulate the spot cash price for West Texas Intermediate crude delivered at Cushing, Okla, on Nov. 26, 2003, by attempting to influence downward the market assessment for the crude that day by Platts, McGraw-Hill Co.'s energy news and price-reporting service.

Platts derives its WTI market assessment, which is used as a benchmark price in some transactions, from trading activity during a particular 30-min period of the physical trading day. CFTC said Marathon priced about 7.3 million bbl/month of physical crude off the assessment at the time in question.

CFTC charged that on Nov. 26, 2003, Marathon purchased WTI contracts on the New York Mercantile Exchange with the intention of selling physical WTI during the Platts window at prices intended to drive the reporting service's WTI spot cash assessment downward. The company also offered WTI through the prevailing bid at a price level aimed at driving the Platts WTI assessment lower, the regulator said.

WoodMac: 2007 lease sales forecast at $1 billion

Edinburgh consultant Wood Mackenzie Ltd. forecasts that proceeds from this year's Gulf of Mexico lease sales 204 and 205, based on past total winning bids, could reach $1 billion.

The estimate represents a high not seen in the region for a decade, WoodMac said in its recent report, "GOM Lease Sales 204 and 205 exposed."

Also in that report, WoodMac identifies 594 deepwater blocks that may be included—double the annual average number of leases offered between 1997 and 2006, the report said.

WoodMac warned, however, that the anticipated higher bid totals and more leased acreage will not necessarily lead to a proportional increase in exploration and production.

According to Matthew Jurecky, Americas upstream analyst for Wood Mackenzie, "Tightness in the deepwater oil field services market, especially in drilling rigs, is likely to limit the benefits of accumulating a mass of blocks as happened a decade ago."

In 1997 a record 1,242 deepwater blocks were leased, representing 255% more than the 10-year average for 1997-2006. That record amount was followed by a further wave of blocks in 1998 with 878 leases, he said.

"Due to a combination of incentives such as deepwater royalty relief, robust oil and gas prices, and technological advances," he said, "companies leased more than they were physically able to explore. A rig conundrum followed as a result of higher oil prices, increased production commitments, and frontier plays becoming more feasible; companies could not even drill potentially exciting blocks in order to get a lease term extension."

Now 10 years later, he pointed out that these leases are "expiring and up for grabs."

Jurecky said the WoodMac analysis identifies 594 deepwater blocks within Minerals Management Service deadlines for inclusion in the 2007 lease sales, compared with 245—the average number of newly expired blocks offered for lease in 1997-2006.

"Many of these deepwater blocks are located in plays which could lead to impressive finds," he added.

He said the area likely to draw most attention is the Lower Tertiary, which covers areas in Alaminos Canyon, Keathley Canyon, and Walker Ridge. The report indicates that 41% of the blocks Wood Mackenzie identified are in this area, and interest is likely to be fueled by the successful flow test carried out last year at Chevron Corp.'s Jack well.

Complaints dismissed against Chevron in Ecuador

The US District Court for the Northern District of California dismissed complaints Aug. 3 against Chevron Corp. filed on behalf of three Ecuadorians.

The court said the plaintiffs had fabricated claims that they or their relative had cancer caused by the former operations of Chevron subsidiary Texaco Petroleum Co. in Ecuador.

The three plaintiffs, Gloria Chamba, Luisa Gonzales, and Gonzales's husband, Nixon Rodriguez Crespo, were among a group of seven Ecuadorians who brought personal injury claims against the US major.

According to the lawsuits filed against Chevron, Chamba claimed her son was diagnosed with leukemia, Gonzales claimed to have been diagnosed with breast cancer, and Crespo's claim was for "loss of consortium" related to his wife's cancer claim.

Judge William Alsup dismissed the personal injury claims by the three plaintiffs finding that the two women had admitted during cross-examination at sworn depositions that their cancer claims were false, and thus Crespo's claim was also without merit. ✦

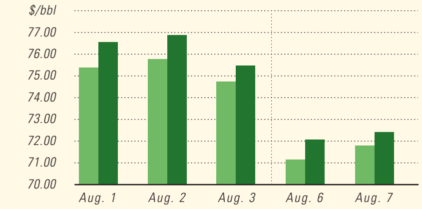
Exploration & Development — *Quick Takes*

Total has eleventh oil discovery off Angola

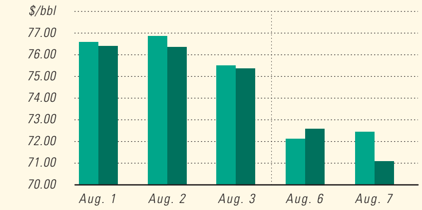
Operator Total E&P Angola and Sonangol have tested 2,130 b/d of oil through a $^{32}/_{64}$-in. choke from the Colorau-1 exploration well on deepwater Block 32 off Angola. The find is in the northeastern part of the block, about 16 km northeast of Manjericao, a 2006 discovery, Total said.

Industry Scoreboard

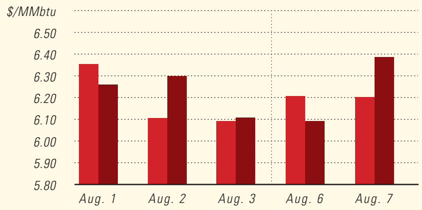
IPE BRENT / NYMEX LIGHT SWEET CRUDE



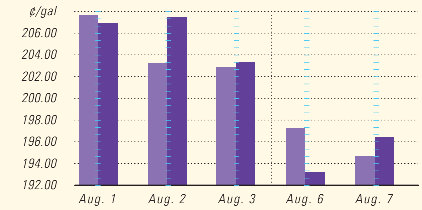
WTI CUSHING / BRENT SPOT



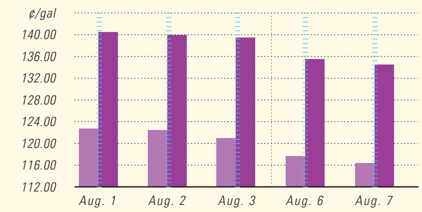
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



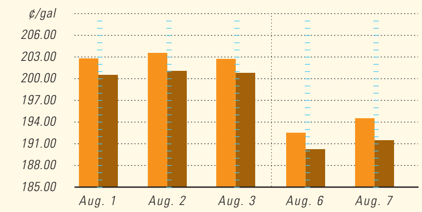
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

US INDUSTRY SCOREBOARD — 8/13

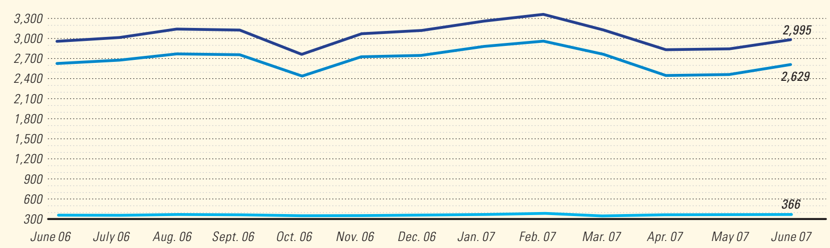
Latest week 7/27	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,681	9,573	1.1	9,279	9,160	1.3
Distillate	4,075	3,913	4.1	4,255	4,148	2.6
Jet fuel	1,639	1,698	–3.5	1,631	1,616	0.9
Residual	718	659	9.0	775	717	8.1
Other products	4,883	4,760	2.6	4,852	4,817	0.7
TOTAL DEMAND	20,996	20,603	1.9	20,792	20,459	1.6
Supply, 1,000 b/d						
Crude production	5,197	5,175	0.4	5,178	5,094	1.5
NGL production[2]	2,396	2,413	–0.7	2,344	2,178	7.6
Crude imports	10,236	10,191	0.4	10,147	10,038	1.1
Product imports	3,698	3,668	0.8	3,589	3,571	0.5
Other supply[3]	939	1,251	–24.9	915	1,121	–18.4
TOTAL SUPPLY	22,466	22,698	–1.0	22,173	22,002	0.8
Refining, 1,000 b/d						
Crude runs to stills	15,811	16,158	–2.2	15,190	15,138	0.3
Input to crude stills	15,982	16,077	–0.6	15,449	15,486	–0.2
% utilization	91.6	92.4	—	88.6	89.1	—

Latest week 7/27	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	344,531	351,028	–6,497	333,723	10,808	3.2
Motor gasoline	204,720	204,134	586	210,868	–6,148	–2.9
Distillate	126,542	123,653	2,889	132,558	–6,016	–4.5
Jet fuel-kerosine	41,119	40,665	454	40,054	1,065	2.7
Residual	37,190	37,503	–313	42,861	–5,671	–13.2
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	21.8	22.4	–2.7	21.3	2.3	
Motor gasoline	21.1	21.1	—	22.0	–4.1	
Distillate	31.1	30.5	2.0	32.0	–2.8	
Propane	49.4	46.1	7.2	68.5	–27.9	
Futures prices[5] **8/3**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	76.77	75.35	1.42	75.07	1.70	2.3
Natural gas, $/MMbtu	6.25	5.98	0.27	7.62	–1.37	–18.0

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

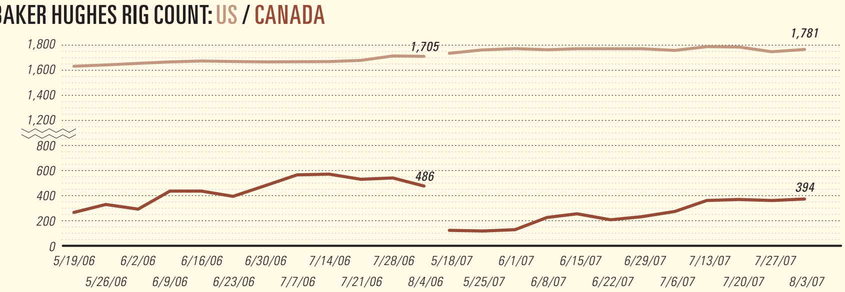
Sources: Energy Information Administration, Wall Street Journal

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

The well, the eleventh exploration well on the block, was drilled in 1,700 m of water and hit Upper Oligocene oil-bearing reservoirs.

The partners are carrying out technical studies to fully evaluate the drilling results, and they plan to carry out extra drilling across the acreage. The consortium wants to assess the feasibility of a first development zone in the eastern part of the block. Studies will evaluate the development potential of the other 10 discoveries made on the block since 2003, all of which indicate its major potential. In May Total and its partners reported the last two oil discoveries on the block (OGJ Online, May 21, 2007).

Total holds a 30% interest in the block, and Sonangol is the concessionaire. Other partners in Block 32 are Marathon Oil Co. 30%, Sonangol EP 20%, Esso Exploration & Production Angola (Overseas) Ltd. 15%, and Petrogal 5%.

Western Desert-Nile Delta discoveries grow

Chile's Sipetrol International SA and Oil Search Ltd., Sydney, are testing a third exploratory well after two oil discoveries in the northeastern part of Egypt's Western Desert. They plan to start production in the third quarter of 2007. The companies' Shahd and Ghard discoveries 80 miles west of Cairo have proven that the Western Desert petroleum system extends into the East Ras Qattara concession. The companies hope to start production before the end of 2007. Adjacent concessions have production facilities.

The Shahd-1 discovery well went to TD 3,479 m in the southwestern part of the block in late 2006 and drillstem tested 700-1,000 b/d from Cretaceous Lower Bahariya and 360-600 b/d of 39-41° gravity oil from Upper Bahariya on artificial lift.

The Ghard-ST1 discovery well, 12 km northeast of Shahd-1, flowed 2,026 b/d of 40° gravity oil and gas at the rate of 2.6 MMcfd in 2 hr on a ¾-in. choke from Lower Bahariya at 3,341-47 m and 3,350-54 m.

Rana-1, 12 km southeast of Ghard-1, was under test in early August after cased-hole log evaluation indicated several potential oil-bearing intervals in the Cretaceous Bahariya and Kharita formations. Rana-1 is one of 12 similar prospects in a chain of structures trending easterly from Shahd-1.

Oil Search also plans to start incremental production in 2007 from Area A, consisting of four development and two exploration concessions totaling 400 sq km on the Gulf of Suez west bank. The development concessions include Kareem, Shukheir, Um El Yusr, Ayun, and Kheir shallow oil fields discovered in 1958-72.

Brunei, Total unit to spud well off Borneo

The government of Brunei and Total E&P Borneo are preparing to spud the MLJ2-06 well 50 km off the island of Borneo.

The MLJ2-06 well is about 25 km from Champion oil field, where Brunei Shell Petroleum Co. Sdn. Bhd. (BSP) last year reported the start of a third phase of oil production (OGJ, Jan. 16, 2007, Newsletter).

Brunei Energy Minister Pehin Dato Awang Haji Yahya said the MLJ2-06 well could be "one of the most challenging" ever drilled in Southeast Asia because of high temperatures and pressures and environmental controls.

Total's drilling manager, Yannick Marcillat, said the MLJ2-06 is one of Total's most challenging wells in the region because it is deeper and has greater pressure than the firm's other wells.

"This particular well has a very high pressure with 17,000 psi, and we have to be very careful when the pressure comes to the surface," Marcillat said. "Besides, it is hotter at 170° C. so it is a bit complicated when we run electronic equipment as the temperature is very high for the equipment."

The Maersk Completer jack up rig, built in Singapore and towed to Brunei, will drill the well. It has been prepared for high-pressure, high-temperature drilling.

According to Marcillat, the rig is under a 1-year contract, with 170 days scheduled for the MLJ2-06 well and the remainder of the time for other projects in the region. The MLJ2-06 is to be drilled to 22,000 ft. ✦

Drilling & Production — *Quick Takes*

Tui area fields start flow off New Zealand

The Tui Area Development in the offshore Taranaki basin of New Zealand has come on stream 19 months after the final investment decision and some 3 years after discovery.

The development encompasses three adjacent oil fields about 50 km offshore. It includes production from four subsea wells incorporating extended horizontal sections in the reservoirs and connected to the Umuroa floating production, storage, and offloading vessel.

Project operator Australian Worldwide Exploration Ltd. (AWE), Sydney, says the production will be ramped up to a peak rate of 50,000 b/d during August and is expected to total around 10 million bbl in the first year.

Proved and probable reserves are estimated at 28 million bbl.

When fully commissioned, Tui will be New Zealand's largest oil producing operation.

The final cost stands at $269 million, 10% more than the previous estimate. Much of the overrun has been due to bad weather affecting the offshore construction activities.

Participants are AWE 42.5%, Mitsui E&P New Zealand Ltd. 35%, New Zealand Oil & Gas Ltd. 12.5%, and Pan Pacific Petroleum NL 10%.

TNK-BP launches $2 billion rig tender

TNK-BP is looking for up to 60 dedicated drilling rigs in tenders worth more than $2 billion to maintain output from mature oil and gas fields and prepare for new production in 2008 from eastern Siberia.

TNK-BP wants to lease rigs for up to 5 years with options to extend.

"Contractors will be requested to tender advanced rig designs which utilize upgraded, efficient, and environmentally friendlier operating systems and equipment," TNK-BP said.

It wants rigs that have triplex pumps, variable speed drives, and environmentally advanced mud systems. Those tendered should have a reduced environmental footprint, mechanical pipe-handling, reduced discharges, energy efficiency, and reduced personnel exposure to safety risks.

More than 20 companies have prequalified to participate in the tender, two thirds of them is Russian. The winners will be informed in October, and rigs are to be in place in January 2008.

TNK-BP described the long-term rig tender as the largest in the Russian industry.

ADMOC lets contract to lift Zakum flow

Abu Dhabi Marine Operating Co. has let a contract to Technip of Paris and National Petroleum Construction Co. of Abu Dhabi for work that will raise production capacity of giant offshore Zakum oil field.

Under the engineering, procurement, and construction contract, the firms will install gas processing and compression facilities on a new gas compression platform bridge-linked to the existing lower Zakum complex. The new platform will have two gas turbine-driven centrifugal compression trains, a triethylene glycol dehydration unit, an air cooling unit, and a vapor recovery system.

The facilities are to be operational in January 2010. No production increment has been disclosed.

Zakum field, discovered in 1963, has been producing since 1967. ✦

Processing — *Quick Takes*

Shell agrees to sell three French refineries

Royal Dutch Shell has signed deals to sell three French refineries with a combined capacity of more than 300,000 b/d to Basell Polyolefins, Hoofddorp, the Netherlands, and Petroplus Holdings AG, Zug, Switzerland.

The refineries are among Shell's smallest and oldest. Shell said earlier this year that it was carrying out a review of nonstrategic assets (OGJ Online, Jan. 15, 2007).

Basell has agreed to pay $700 million to Societe des Petroles Shell to buy the 80,000 b/d Berre-l'Etang refinery site complex and associated infrastructure in France. The deal should be completed in early 2008.

The refinery produces naphtha, LPG, fuels, bitumen, and heating oil. Basell has a steam cracker, a butadiene extraction unit, and polypropylene and polyethylene plants adjacent to the refinery and a polyethylene plant at nearby Fos sur Mer.

Petroplus Holdings has signed separate letters of intent with Shell International Petroleum Co. Ltd. to acquire the Petit Couronne and Reichstett Vendenheim refineries in France. Petroplus will pay $875 million, including working capital of $400 million.

The parties hope to reach agreement on a sale in 2008.

The 164,000-b/cd Petit Couronne refinery, 130 km northwest of Paris on the River Seine, produces 40% middle distillates and 20% gasoline. Its major units include crude and vacuum distillation, fluid catalytic cracking, visbreaking, hydrotreating, reforming, lubricant production, and bitumen production. It receives crude via a 70-km pipeline from the port at Le Havre. The crude slate is about 70% high-sulfur.

The 80,000-b/cd Reichstett Vendenheim refinery is in Alsace, France, near Strasbourg, about 5 km from the River Rhine. It produces 45% middle distillates and 20% gasoline. Major units are crude and vacuum distillation, fluid catalytic cracking, visbreaking, hydrotreating, reforming, and bitumen production. Crude arrives via a pipeline from Fos. The crude slate is about 45% high-sulfur.

Shell approved for ProJet acquisition in Malaysia

Royal Dutch Shell PLC has received Malaysia's approval to acquire 100% of ConocoPhillips's wholly owned subsidiary Conoco Jet (Malaysia) Sdn. Bhd., which operates the ProJet retail marketing assets in Malaysia.

The deal comprises 44 ProJet-branded retail outlets and 14 vacant land sites primarily in Kuala Lumpur, Selangor, and Johor.

The sites will be rebranded as Shell over the next 3 months, but all ProJet retail outlets will immediately begin to carry Shell fuels, said Mohzani Wahab, managing director of Shell Malaysia Trading Sdn. Bhd.

In addition to the ProJet retail stations, Shell is looking to add another 30 new stations by yearend.

With its existing stations, Shell expects to have about 900 Shell retail sites throughout Malaysia by yearend, said Mohzani.

Woodside gives formal nod to Pluto LNG project

Perth-based Woodside Petroleum Ltd. has agreed to spend $11.2 billion (Aus.) to develop an LNG project using gas from its wholly owned Pluto and Xena fields in Western Australia's Carnarvon basin, 190 km off Karratha.

The timetable calls for first gas to be delivered by yearend 2010.

The initial phase will involve a single LNG production train having a 4.3 million tonne/year capacity on the Burrup Peninsula and a 180 km, 36-in. subsea pipeline from the fields.

A field platform at Pluto, moored in 85 m of water, will be connected to five subsea wells. A second phase, which will require additional funding approval, will include compression on the platform and a tie-in to the smaller Xena field. Onshore facilities will also include storage tanks and a marine loading terminal.

The company said that reservoir studies indicate the combined dry gas content for Pluto and Xena has increased to 5 tcf from 4.5 tcf.

Woodside has spent about $800 million (Aus.) on preliminary studies at the field and preparatory work at the LNG site. The additional funding just approved is higher than Woodside's earlier estimates of $6-10 billion.

Funding will be provided by cash flow from the company's Australian operations along with a fully underwritten dividend reinvestment plan and the issuance of corporate debt.

The company had already preapproved $1.4 billion for long-lead items and LNG plant site preparation. Earthworks began in January.

Woodside received provisional environmental approval in June despite its earlier having failed marine standards set by the Western Australian Environment Protection Authority. The EPA said the project could proceed if Woodside agreed to a range of conditions for the pipeline access route. Sales contracts have been signed with Japanese companies Kansai Electric and Tokyo Gas.

CPC taps ABB Lummus for petrochemical work

CPC Corp., Taiwan, has let a contract to ABB Lummus Global for a petrochemical complex to be built in Lin Yuan, Kaohsiung, Taiwan.

The complex will use Lummus SRT VI cracking furnaces and recovery technology to produce 600,000 tonnes/year of ethylene. It will use proprietary Lummus olefins conversion technology based on metathesis to produce 432,000 tonnes/year of propylene.

Lummus, through a partnership with BASF AG, also will supply a 130,000 tonne/year butadiene extraction unit.

The complex is scheduled to begin operations in late 2013.

PetroChina refineries to get Axens units

PetroChina Co. Ltd. will use Axens technology for deep hydrodesulfurization of FCC gasoline in new units at two refineries.

It will install a 32,800-b/d unit using Axens Prime-G+ technology at its Jinxi Petrochemical Complex and an 18,200-b/d unit at its Dagang Petrochemical Complex in Tianjin Municipality. When the units are on stream, gasoline pool sulfur content will be less than 50 ppm at Jinxi and 25 ppm at Daqang, Axens said. ✦

Transportation — *Quick Takes*

Greece, Turkey, Italy sign pact on gas pipelines

After months of negotiations, Greek, Turkish, and Italian officials have signed an agreement to build a pipeline system to transport natural gas from the Caucasus to Western Europe through Turkey and Greece by 2011.

Turkish Energy and Natural Resources Minister Hilmi Guler said the agreement will allow Turkey to buy at a cheaper price 15% of the gas passing through the Turkish sector of the proposed pipeline. Greece's Minister of Development Dimitris Sioufas described the project as "a work of strategic importance."

The project is a system of three pipelines: one linking Greece and Turkey that is already nearing completion, a 217-km underwater pipeline from Greece to Italy, estimated to cost €300 million; and a 590-km pipeline connecting the western terminus of the Greece-Turkey pipeline, in Komotini, Greece, to the eastern terminus of the Greece-Italy pipeline near the Greek port of Igoumenitsa at a cost of more than €600 million. Total investment earlier was estimated to exceed €1 billion and will be partly funded through the European Union's Fourth Community Support Framework (2007-13).

The Turkey-Greece pipeline will have a transport capacity of 11.5 billion cu m/year of natural gas. The Greece-Italy subsea pipeline is to have a capacity of 8-8.8 billion cu m/year. The difference is to be channeled into the Greek gas market, as well as Albania and the former Yugoslavian Republic of Macedonia, officials said. Bulgaria also has expressed interest in obtaining natural gas from Greece.

The Turkey-Greece link initially was scheduled to be completed in June but is now expected to begin operations in late August. Construction of the subsea Interconnector Greece-Italy (IGI) link is to start next June with completion slated for 2011.

WestPac plans Texada Island LNG terminal

WestPac LNG Corp., Calgary, plans to invest $2 billion to build an LNG terminal combined with a natural gas-fired electric power generation plant on Texada Island, 120 km northwest of Vancouver, BC. The project is expected to be operational in 2013.

Facilities will include a marine jetty and berthing facility capable of unloading and loading ships of 20,000 cu m to 165,000 cu m; possibly two onshore LNG storage tanks, each with a capacity of 165,000 cu m; a gas-fired power generation facility with a capacity of 1,200 Mw from two trains; and an on-site interconnection with the existing Terasen gas pipeline from the mainland to Vancouver Island.

Project design is still being finalized and could entail only one storage tank with capacity of 200 million cu m, a WestPac spokesman told OGJ.

The company intends to file a project description with regulatory agencies later this year. Construction is scheduled to start in 2009 and continue for 3 years.

WestPac has acquired a long-term lease at Kiddie Point at the north end of Texada Island. This proposed Texada LNG site is in an industrial area and the site is a secure source for natural gas with minimal environmental impact, WestPac said.

WestPac said the Texada Island project also could enhance air quality in the Fraser Valley by allowing BC Hydro to decommission its Burrard thermal power generator, which it currently depends on for peak-demand power supply.

Separately, WestPac has been conducting environmental assessment work for a proposed LNG receipt and transshipment terminal at Ridley Island near Prince Rupert. The Ridley facility will not proceed immediately, but the location could play a future role as a second terminus to serve the north coast when gas demand reaches new levels, WestPac said.

Sonatrach, EDP partner for Iberian gas supply

EDP Energias de Portugal SA in a public filing said a natural gas and power generation partnership with Algeria's state-run Sonatrach will be in place by Oct. 31. The partnership will jointly supply and market gas in Portugal and Spain and partner in combined-cycle gas turbine plants.

Sonatrach, keen to increase natural gas sales to Europe, will provide as much as 2 billion cu m/year of gas to EDP while taking a 25% minimum stake in the gas supply projects. It also will have one representative on EDP's board when the deal is formalized, EDP said.

Other talks are said to include EDP's possible participation in gas plants in Algeria. Earlier this year Algeria announced a tender of about €2.5 billion for five natural gas plants and an underwater cable to Spain. EDP, Iberdrola SA, Enel SPA, and Endesa SA are interested in the bidding. ✦

Calendar

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

OIL&GAS JOURNAL online

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

2007

AUGUST

Diesel Engine-Efficiency and Emissions Research (DEER) Conference, Detroit, (540) 937-1739, e-mail: kim@cemamerica.com, website: www1.eere.energy.gov/vehiclesandfuels/resources/conferences/deer/index.html. 12-16.

Rocky Mountain Natural Gas Strategy Conference & Investment Form, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: cogaconference@aol.com, website: www.coga.org. 13-15.

American Chemical Society National Meeting & Exposition, Boston, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 19-23.

NAPE Summer Expo, Houston, (817) 847-7700, (817) 847-7703 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 23-24.

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

Rocky Mountain Crude Oil Market Dynamics Summit, Denver, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us/events.html. 4-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

Black Sea Oil & Gas Summit, Istanbul, +90 312 454 00 00-1412, +90 312 454 00 01, e-mail: bsogs2007@flaptour.com.tr, website: www.bsogs2007.org. 5-6.

Iraq Petroleum Conference, Dubai, +44 (0)20 7978 0075, +44 (0)20 7978 0099 (fax) website: www.thecwcgroup.com. 8-10.

Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

Global Refining Strategies Summit, Houston, (416) 214-3400, x3046, (416) 214-3403 (fax), website: www.globalrefiningsummit.com. 10-11.

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

Annual LNG Tech Global Summit, Rotterdam, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.lngsummit.com. 10-12.

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

EXPOGAZ Gas Congress, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 11-13.

European Gas Forum, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 12-13.

AAPG Annual Eastern Meeting, Lexington, (859) 257-5500, ext. 173, website: www.esaapg07.org. 16-18.

United States Association for Energy Economics/IAEE North American Conference, Houston, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 16-19.

Russia & CIS Petrochemicals & Gas Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 17-18.

API Fall Refining and Equipment Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-19.

✦Annual American School of Gas Measurement Technology Event, Houston, (972) 224-5111, (972) 224-5115 (fax). e-mail: asgmt2007@aol.com, website: www.asgmt.com. 17-20.

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 19-20.

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

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

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

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

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

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 27-28.

OCTOBER

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

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

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

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

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

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

Calendar

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

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

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

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

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

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

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

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

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

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

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

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 15-19.

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

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

PIRA Global Political Risk Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 17.

PIRA New York Annual Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 18-19.

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 22-24.

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

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

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

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

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

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

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

Methane to Markets Partnership Expo, Beijing, (202) 343-9683, e-mail: asg@methanetomarkets.org, website: www.methanetomarkets.org/expo. Oct. 30-Nov. 1.

NOVEMBER

IADC Annual Meeting, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 1-2.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 6-8.

IPAA Annual Meeting, San Antonio, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

✦Regional Mangystau Oil & Gas Exhibition & Conference, Aktau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-9.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

SPE Annual Technical Conference and Exhibition, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-14.

World Energy Congress, Rome, +39 06 8091051, +39 06 80910533 (fax), e-mail: info@micromegas.it, website: www.micromegas.it. 11-15.

API/NPRA Fall Operating Practices Symposium, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 13.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 13-15.

✦Turkemenistan International Oil & Gas Conference, Ashgabat, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 14-15.

Australian Society of Exploration Geophysicists International Geophysical Conference & Exhibition, Perth, (08) 9427 0838, (08) 9427 0839 (fax), e-mail: secretary@aseg.org.au, website: www.aseg.org.au. 18-22.

ERTC Annual Meeting, Barcelona, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 19-21.

Asia Pacific Natural Gas Vehicle Conference & Exhibition, Bangkok, +66 0 2617 1475, +66 0 2271 3223 (fax), e-mail: angva@besallworld.com, website: www.angvaevents.com. 27-29.

IADC International Well Control Conference & Exhibition, Singapore, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.

DECEMBER

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

Celebrating 40 Years of Simulation Leadership!

In 1967, the first commercial distillation simulation program was born. SimSci-Esscor named it SP03. Following decades of unwavering dedication, infant products like SP03 and SSI/100 have evolved into what are respected today as PRO/II®, PIPEPHASE®, ROMeo®, and DYNSIM® - the industry's most trusted simulators.

A History of SimSci-Esscor Firsts

- **1967** - Simulation Sciences Inc. and SP03 Were Born
- **1973** - SSI/100 Offered Keyword and Time-sharing
- **1978** - PROCESS® for Comprehensive Flowsheets
- **1986** - PIPEPHASE for Comprehensive Fluid Flow
- **1989** - Rigorous On-line Modeling (ROM™)
- **1994** - PRO/II with PROVISION® Windows® Environment
- **1998** - ROMeo Off-line/Real-time Optimization
- **2003** - DYNSIM Integrated Engineering Study, Control Check-out, and OTS Dynamic Simulation

And the momentum continues. SimSci-Esscor is growing and developing in upstream, EPC, OTS, and integrated simulation using the SIM4ME® common modeling environment.

Yeah, we're still obsessed. Our soul, and our sole focus will always be on simulation. Since inception, and every day moving forward, SimSci-Esscor and its people remain steadfast in keeping our loyal users prepared for future growth with the industry's most reliable simulation software technologies and services.

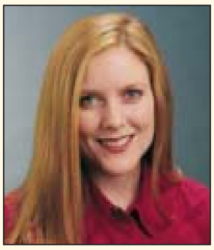
FREE white papers and software trials at www.simsci-esscor.com

If 40 is the new 30, then no thanks. We are proud of our longevity. Because to us, each new line is not shunned as a wrinkle, but embraced as another new path in our quest to provide decades of responsive simulation expertise.

And we're revving up for 40 years more!

invensys®
SIMSCI-ESSCOR™
The Power of Simulation3℠

Oil market divergences



Marilyn Radler
Senior Editor-Economics

There have been a couple of interesting divergences concerning the oil market recently. First, two high-profile forecasts of worldwide demand for oil are receiving a bit of attention from market analysts. The recent outlooks differ as to how much oil the world will need in the next few years. What lies behind these differences are the assumptions of economic growth.

Also, there recently has been a divergence in the price of crude oil and the price of gasoline at US pumps. Retail prices of the fuel fell in late July at the peak of driving season in the US, while crude prices rallied above $70/bbl. What lies behind these differences is the same problem that has been the bottleneck in the market for about 2 years now: refining. Also, anticipated and real oil production disruptions and a fair amount of speculation in the futures markets have elevated the crude price.

Future demand

Last month the International Energy Agency released its Medium-Term Oil Market Report. IEA's estimates call for worldwide demand for oil products to average almost 92 million b/d in 2010 and nearly 96 million b/d in 2012.

And the Organization of Petroleum Exporting Countries released its latest World Oil Outlook in June. The group looks for global oil demand in 2010 to be just 89.7 million b/d.

This difference in forecasts deserves noting. With the more conservative outlook, OPEC is being cautious, keeping an eye on refinery operations and not wanting to see prices sink as it puts what it would consider too much oil on the market. If the organization is correct, then prices may be more stable than if it is wrong. In the case that the world does need much more oil, then prices will spike in a very tight crude market.

How strong the global economy is during the next 3-5 years will heavily affect the amount of oil the world consumes. And especially important to demand growth will be the strength of the economies in large developing countries, including China and India.

Even the two groups' forecasts for 2008 are quite different. IEA forecasts demand next year will average 2.18 million b/d more than this year. Meanwhile, OPEC projects a 1.34 million b/d climb from this year's average worldwide demand, as economic growth slows.

IEA assumes that the global economy will be strong enough to sustain oil demand growth and that weather will play a role. The agency expects global oil product demand to rise by a robust 2.5% in 2008, largely due to a weather-related rebound in the member countries of the Organization for Economic Cooperation and Development and to strong demand in non-OECD countries.

In its forecast for next year, OPEC says that on the supply side we need to look at the entire supply chain, as the downstream sector is a key element for market stability.

"Any easing in refining tightness will depend on the evolution of refinery capacity expansion and demand growth. In this regard, however, more needs to be done to make sure the downstream sector does not lag behind, particularly given recent announcements indicating policy pushes for an expanded use of biofuels, furthering unease amongst downstream investors," OPEC said.

But OPEC is likely to continue to protect its crude export revenues by holding the reins on output.

Price differences

Crude and product prices typically move in the same direction, but this was not so over the past 2 months.

Crude reached an all-time high on the New York Mercantile Exchange last month. On July 31, the front-month contract closed at $78.21/bbl for September delivery.

Retail gasoline prices were headed lower, though. This decline came with a long-awaited uptick in refinery utilization, which surpassed 92% by the end of July after hovering below 90% for most of 2007. Refinery outages indeed have been responsible for bolstering prices throughout 2006 and 2007.

The average regular unleaded self-service pump price in the US on Aug. 1, 2007, was $2.918/gal. This is the lowest since late-April, according to OGJ statistics. Pump prices peaked at an average of $3.176/gal on May 30, 2007, OGJ statistics show.

At the start of this month, crude futures began to dip only after fears grew that economic growth was slowing more than previously expected, as equities markets weakened, and lending activity, especially mortgages, continued to deteriorate. ✦

Editorial

House energy mischief

The Democrat-controlled House has given Republicans the chance to act once again as though they believe in the fundamentals of their party. It has passed two energy bills so breathtakingly at odds with US needs that the job of discrediting the nonsense should be easy. But are Republicans up to it?

The gasoline price increases that have agitated US energy politics into near hysteria send a simple message that federal officials must heed: The US needs a strong increase in its supply of affordable energy. The country is part of a world in which rising demand has encountered physical limits on systems—natural and mechanical—that deliver energy in useful forms. The strains have been aggravated by geopolitical tension, by long-standing political limits in the US on supply-enhancing activities such as drilling and refinery construction, and by natural disasters.

Popular demons

These are sufficient and evident reasons for prices of petroleum products to have risen these past few years. The popular demons that motivate energy politics have not driven up prices. As has been proven repeatedly, oil companies are not manipulating prices. The Organization of Petroleum Exporting Countries isn't levitating crude prices, either. Notwithstanding OPEC's controversial production restraint, the ability of the group's key members to raise output of the light, sweet crude the market needs in fact remains limited.

Prices will ease, as they always do, when supply increases and consumption subsides. Given the chance, the market will recreate both conditions the cheapest way possible. High prices do not demonstrate the need for government action, which inevitably interferes with the market's self-correcting mechanisms.

Yet action by government, in deliberate subversion of the market and in direct conflict with national need, is what the House has just passed. The bills raise taxes on providers of oil and gas in order to subsidize much costlier energy forms with far less potential to boost total energy supply. They treat as a pariah the industry that should be investing heavily in production, refining capacity, and pipelines if future US energy needs are to be met. And they mandate sales of politically favored energy types, assigning government the role of telling individuals what to buy and producers what to sell.

"The House propelled America's energy policy into the future," crowed House Speaker Nancy Pelosi (D-Calif.) after the bills passed. Wrong. The House repeated past mistakes. At enormous cost to Americans, its mischief would keep the energy market from evolving as it should: as an economic process that summons into affordable use renewable and other new energy forms as essential supplements to traditional supply, which must be allowed to grow.

Democrats have played their ludicrous hand. Someone now needs to remind a strangely frenzied national capital that the best energy policies are those that rely on the free interplay of supply, demand, and price. It's up to Republicans, if any of them will do it, to assert the market principles they once claimed to believe.

President's role

President George W. Bush should take the lead. Nothing constructive can come from reconciliation of the House mess with a little-better energy bill passed earlier by the Senate. Bush should promise a veto. And he should anchor his reasons in arguments steeped in a recommitment to a free energy market.

This will require some backtracking. Bush set the country on a federally charted energy course in his 2006 state-of-union address, in which he groaned about the country's being "addicted to oil" and took aim at the impossible target of ending US dependence on oil from the Middle East. Since then, US energy policy-making has been a mad rush after energy fantasies and federal dollars.

Bush was wrong to deploy the addiction analogy. He has erred since with his hop-scotching mandates for ethanol and other renewable boondoggles. But he doesn't have to say so or express regret. He just needs to use his veto to stop a Congress that has lost all sense on energy and to explain himself within a market perspective that the nation can only hope he hasn't forgotten. ✦

Technology drives methane emissions down, profits up

Brian Gillis
ICF International
Fairfax, Va.

Suzie Waltzer
US Environmental Protection Agency
Washington, DC

Milton W. Heath III
Heath Consultants Inc.
Houston

Jim Cormack
TransCanada
Calgary

Krish Ravishankar
Occidental Oil & Gas Corp.
Houston

The extent of methane emissions worldwide is significant and indisputable. The economic benefits from containing such emissions are equally compelling. These include higher revenue from additional gas sales and labor savings, carbon credits, and greater process efficiency.

This article summarizes a number of proven methods to identify, measure, and reduce methane emissions from a wide range of equipment in production and processing facilities as well as through transmission and distribution facilities in the gas supply chain.

In addition, the article provides examples of measures companies are taking and technologies they are using to deliver greater revenue as well as environmental benefits to shareholders worldwide.

The case studies presented here and the complete range of projects being implemented by industry demonstrate several facts:

- Identification and quantification of existing methane emissions constitute a key first step to project implementation.
- Proven recovery technologies provide compelling economic and environmental benefits.
- Company leadership at the highest levels accelerates implementation by aligning resources and capital to utilize emissions reductions.

Containment of methane emissions from the global oil and gas infrastructure represents an opportunity to improve the environment and generate substantial economic and energy benefits.

GAS, OIL INDUSTRY METHANE EMISSIONS Table 1

Country	1995	2005	2015
	Estimated methane emissions Million tonnes CO_2 equivalent		
Russia	241.5	172.7	186.7
US	152.1	127.6	155.0
Mexico	44.6	77.2	136.7
Ukraine	82.1	90.8	98.2
Venezuela	35.1	45.4	63.3
India	12.6	26.0	49.9
Uzbekistan	30.4	39.7	45.4
Canada	35.1	38.3	40.8
China	2.6	6.3	16.7
Colombia	1.5	1.9	2.7
Total	**637.6**	**625.9**	**795.4**
World	**977.3**	**1,165.0**	**1,569.7**

Source: US EPA, "Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020," June 2006, Appendix B-1

Methane emissions mitigation is of interest not only to operators but also to service providers, investment banks, corporate shareholders, and the public. Methane mitigation work has increased as a result of a collaborative effort by this diverse set of stakeholders.

Global emissions

While methane is a source of clean energy, it also is a very potent greenhouse gas. Lost into the atmosphere each year from oil and gas operations worldwide is nearly 82 billion cu m of methane, which equates to a loss of about $20 billion in revenue.[1] Moreover, these emissions have an equivalent annual greenhouse gas effect comparable to adding more than 200 million vehicles to the roadways.

Key methane conversions

1 tCO_2e	=	1 tonne carbon dioxide equivalent
1 Mcm	=	1,000 cu m
1 Mcm methane	=	14.3 tCO_2e
1 Mcf	=	1,000 cu ft
1 Mcm	=	35.3 Mcf
1 Mcf	=	0.404 tCO_2e

Methane emissions resulting from oil and gas production, processing, transmission, and distribution operations can take the form of unintentional leaks as well as venting from operational processes. Such practices include venting from well cleanups or workovers, reciprocating and centrifugal compressor operation, crude oil and condensate storage tanks, and pipeline repairs. Table 1 indicates methane emission trends in several key countries with established or growing oil and gas infrastructures.

The US Environmental Protection Agency projects that global methane emissions will grow by more than 33% during 2005-15. These emissions represent a compelling opportunity to generate considerable additional revenue with the technologies discussed in the balance of this article.

Mitigation options

Profitable methane emission reduction projects exist throughout the entire gas infrastructure, from wellhead to burner tip. Methane emission reduction strategies generally fall into one of three categories:

- Employing new technologies or upgrading equipment to reduce venting or fugitive emissions.
- Improving operational procedures.
- Enhancing management practices.

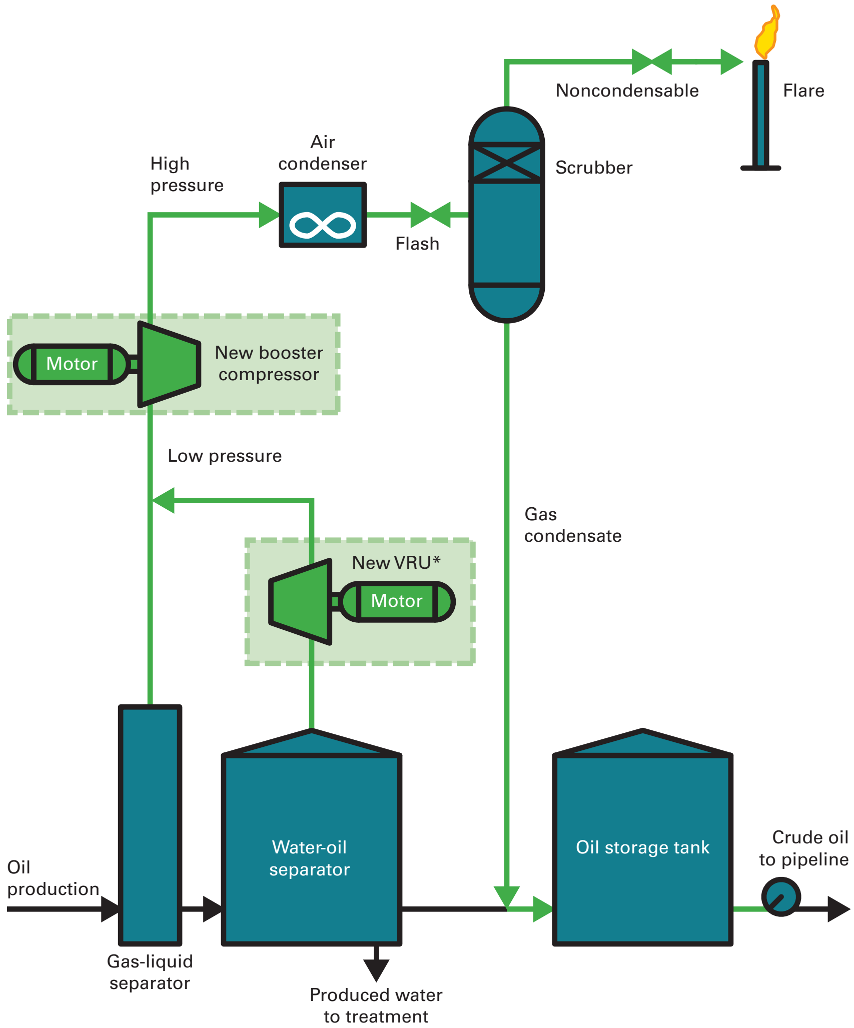
The information presented here updates and expands on analyses previously published in OGJ on cost-effective technologies to cut methane emissions globally.[2]

Various project options such as upgrading compressors, replacing pneumatic devices, and conducting leak surveys have broad applicability globally and across the industry.

Based on EPA emissions estimates and Energy Information Administration production estimates,[3] more than 2.8% of net worldwide dry gas production is emitted to the atmosphere. Each emissions source represents unrealized revenue. Table 2 provides information on proven, cost-effective technologies and practices that have broad applicability in addressing major sources of methane emissions from oil and gas operations. Investment costs for these technologies and processes range from $0 to $324,000, with payback periods ranging from immediate to 21 months. Operators can recover their investments through a number of economic channels, including gas sales revenue, carbon credit revenue, on-site fuel use, reduced labor costs, reduced capital replacement costs, lower environmental permitting costs, and reduced environmental impact. Project examples were selected from representative successful field implementations for specific emissions sources. In each case, operators identify emissions sources, quantify the product loss, and apply off-the-shelf, mature solutions to recover methane.

Proposed Cano Limon methane emissions capture

Fig. 1



*Vapor recovery unit. Note: Green items constitute the new project infrastructure and process flow.
Source: Cano Limon gas capture process flow diagram, Environmental Protection Agency

Tanks

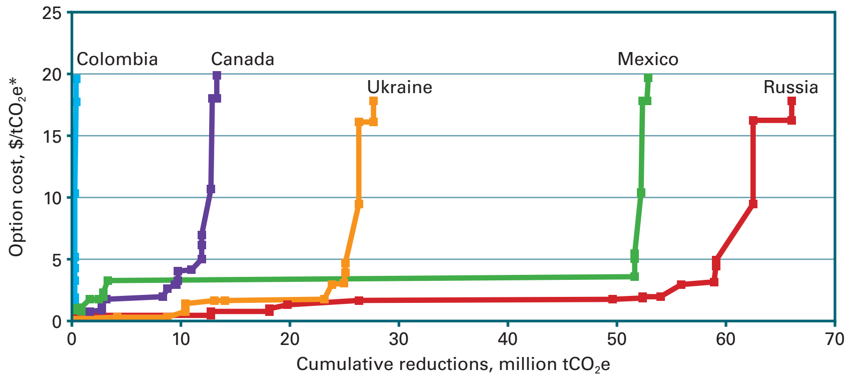
Crude oil and gas condensate production field tanks hold petroleum liquids briefly to stabilize flow or for trucking or pipeline transportation to processing and refinery sites. During storage, light hydrocarbons dissolved in the crude oil—including methane—vaporize or "flash" and vent to the atmosphere from fixed-roof field production tanks. When uncontrolled, these tanks vent 0.2-1.2 cu m/year of methane/bbl of crude oil and condensate.

One way to capture tank emissions is to install vapor recovery units (VRUs) on oil and condensate storage tanks. VRUs are relatively simple compression systems that can recover about 95% of tank vapors for sale or for use on site as fuel. Since tank vapors also include hydrocarbons heavier than methane, on a volumetric basis, the recovered vapors can be more valuable than methane alone. A VRU project under way by Occidental de Colombia (Oxy) illustrates how methane and nonmethane tank vapors can represent economic opportunity.

Oxy's Cano Limon facilities in Colombia produce 35 million bbl/year of crude oil that flows through production site tanks, emitting about 166,000 cu m/year of methane. Oxy identified this product loss and is now modifying its

METHANE EMISSIONS-REDUCTION POTENTIAL, COSTS

Fig. 2



*Tonnes of carbon dioxide equivalent.
Source: Country level methane emissions estimates from: US EPA, "Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020," June 2006, Appendix B-1, and company-specific project results from implementation of a variety of top methane emission reduction technologies and practices from: US EPA Natural Gas STAR recommended technologies and practices (www.epa.gov/gasstar/techprac.htm)

facilities to include VRU and booster compressors to boost vapors to a high pressure (Fig. 1).

Following compression, existing air coolers lower the stream temperature to ambient temperature. The compressed vapor then expands through a valve into a scrubber, which reduces the stream to subambient temperature and condenses the heavier components. Condensed liquids are blended with the crude oil, and noncondensable vapor, including methane, is flared.

The feasibility study estimates vapor recovery and booster compressor investments of about $1.57 million for equipment costs. Operating and maintenance costs are estimated at $805,000/year. For its investment, Oxy will benefit from an estimated incremental 360,000 bbl/year of condensate blended into the crude, worth about $18 million/year at a nominal $50/bbl. The project also eliminates methane venting from tanks.

Compressors

Compressors are a logical focus area for methane emissions due to the variety of emissions encountered with operation of these units. Both reciprocating and centrifugal compressors potentially vent methane when taken out of service. Both compressor types also lose methane through the seal between the driver shaft and compression case.

Many centrifugal compressors are configured with oil seals, called "wet seals," at the point where the rotating driver shaft exits the high pressure case. Wet seal systems circulate oil across the seals to create a barrier between compressed gas and the atmosphere. Although these are very good seals, the seal oil absorbs methane and must be degassed to maintain viscosity and lubricity. The methane-rich gas is normally vented to the atmosphere at remote field locations. A single wet seal centrifugal compressor can vent as much as 1.8 million cu m/year of methane.

Wet seals can be replaced with "dry" seals, which provide the same barrier to high pressure gas leakage with lower operating and maintenance costs and lower methane emissions. Each dry seal upgrade reduces methane emissions by

TOP METHANE EMISSIONS-REDUCTION TECHNOLOGIES, PRACTICES

Table 2

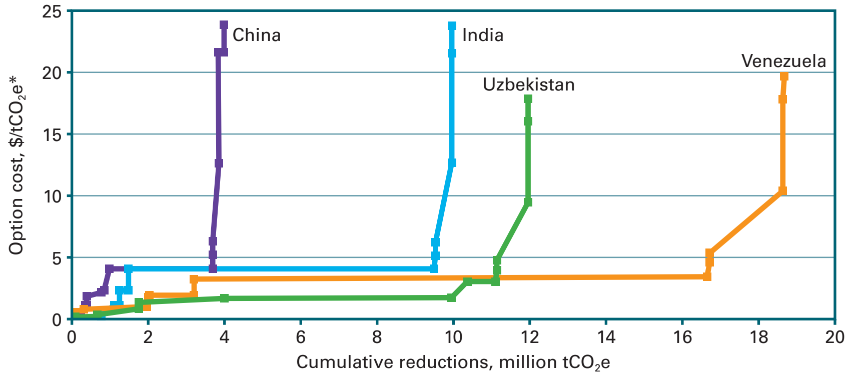
Action	Methane saved,[1] Mcm/year	Value of natural gas saved,[2] $/year	Implementation cost, $	Payback, months
Tanks				
Install vapor recovery units	109-2,142	30,300-606,800	35,738-103,959	3-19
Compressors				
Replace reciprocating compressor rod packing	19	6,055	540	2
Replace centrifugal compressor wet seals with dry seals	1,188	315,840	324,000	10
Keep compressor pressurized when idle	116	30,800	0	Immediate
Route compressor blowdown to fuel gas when idle	151	40,215	1,754	3
Route compressor blowdown to fuel gas and install static seal when idle	183	48,615	4,210	7
Instrumentation and controls				
Replace high-bleed pneumatics	1-5	350-1,400	210-340	3-8
Retrofit high-bleed pneumatics	6	1,610	675	6
Improve maintenance on high-bleed pneumatics	1-7	315-1,820	0-500	Immediate-4
Replace pneumatics with instrument air systems	527	140,000	60,000	6
Component leaks				
Conduct DI&M[3] at compressor stations	775	205,889	47,668	3
Conduct DI&M at gas processing plants	1,004-3,371	200,000-439,000	71,000-182,000	4-5
Conduct DI&M at gate stations	1-5	4,200	27-1,617	Immediate-5
Other—production related				
Perform reduced-emissions completions	8,510	2,669,370	14,260	less than 1
Install plunger lifts	105-407	32,900-127,750	2,591-10,363	2-14
Other—pipeline related				
Repair pipelines with composite wrap	104	27,720	5,648	3
Perform pipeline pump-down	5,268	1,400,000	98,757	1
Other—dehydrator related				
Reduce glycol circulation rates	4-372	2,758-8,338	0	Immediate
Install flash tank separator	7-201	8,338-75,019	6,500-18,800	4-11
Install desiccant dehydrator	24	7,441	15,787	21

[1]Based on 78.8% methane in upstream gas and 93% methane in downstream gas. [2]Natural gas valued at 25¢/cu m ($7/Mcf). [3]Directed inspection & maintenance.
Source: US EPA Natural Gas STAR recommended technologies and practices (www.epa.gov/gasstar/techprac.htm)


Managing a monumental project is one thing.
Managing your career is another story.
What do you do?
Taking your career to the next level isn't easy. At Manpower Professional, our dedicated engineering recruiters understand your skills and where you want to take your career. They have access to the best opportunities with leading-edge companies. Whether it's a permanent placement or contract assignment. So draw up your plan.
manpowerprofessional.com/manage
Manpower®
Professional
© Manpower Inc.

METHANE EMISSIONS-REDUCTION POTENTIAL, COSTS

Fig. 3



*Tonnes of carbon dioxide equivalent.
Source: Country level methane emissions estimates from: US EPA, "Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020," June 2006, Appendix B-1, and company-specific project results from implementation of a variety of top methane emission reduction technologies and practices from: US EPA Natural Gas STAR recommended technologies and practices (www.epa.gov/gasstar/techprac.htm)

METHANE LEAK RATES FOR DIFFERENT FACILITY TYPES

Table 3

Methane leak source	Typical methane leak rate, 1,000 cu m/year
Production well	0.5 to over 10
Processing facility	82
Transmission station	91
Distribution facility	45

Source: US EPA, "Inventory of US Greenhouse Gas Emissions and Sinks"

1.2-1.7 million cu m/year, or 67-98 %.

Petroleos Mexicanos (Pemex), Mexico's nationally owned petroleum company, has upgraded three wet seal centrifugal compressors with dry seals as part of a larger methane emissions reduction strategy. Dry seal first year investment costs are typically $317,000/compressor or $12.40/tonne of carbon dioxide equivalent (tCO_2e) methane saved. Benefits of the investment include increased throughput, reduced methane emissions, and avoided seal oil system operating and maintenance costs, which pay back the investment in about 10 months. On average, operators report saving about $316,000/year in reduced methane emissions and $88,000/year in avoided operating costs on each compressor.

Instrumentation, controls

Gas-powered pneumatic valve control devices are one of the largest sources of methane emissions from oil and natural gas operations. The emissions come from a continuous "bleed" or gas vent stream that transfers a process measurement to a control valve actuator. Many pneumatic devices worldwide are considered "high-bleed" devices and typically vent more than 1,500 cu m/year of methane for each control loop, which consists of the valve actuator and the process measurement control such as a level, pressure, or temperature control. While facilities that are able to do so could implement pressurized air, electric controls, or mechanical controls—the only power source available at remote, nonelectrified sites—may be pressurized gas.

Operators are replacing older model, high-bleed controllers with "low-bleed" gas pneumatic devices, which can perform the same function but reduce bleed rates by 1,000-5,000 cu m/year. As low-bleed pneumatic devices have become the industry standard, their capital costs are often lower than high-bleed pneumatic devices. Methane savings from low-bleed devices pay back the device replacement within 3-8 months.

Marathon Oil Co. is one operator that reduced product loss from pneumatic devices. The company used the Bacharach Inc. Hi Flow Sampler to survey controllers at 50 production sites. It found that high-bleed devices accounted for 35 of its 67 level controllers, 5 of the 76 pressure controllers, and 1 of its 15 temperature controllers. Measured gas emissions amounted to 145,000 cu m/year. Marathon concluded that high bleed rates can often be identified qualitatively by sound, facilitating identification of the product loss.[4]

Component leaks

All valves, flanges, connections, open-ended lines, and other components in the gas infrastructure are potential sources of methane emissions (Table 3). Unintended component leaks develop over time in response to temperature fluctuations, pressure, corrosion, mechanical vibration, defective installation, and wear. These leaks are usually invisible and odorless and therefore go unnoticed. The very large number of components with individually small leaks compound into significant methane losses.

One proven solution for addressing these leaks is implementing a directed inspection and maintenance (DI&M) program. DI&M is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair. Several leak screening techniques are commercially available, ranging from a soap solution to infrared leak imaging cameras (Table 4). Baseline survey results typically show that the large majority of fugitive methane emissions are from a relatively small number of leaking components that can be targeted for monitoring. A simple investment in labor yields benefits of increased production or throughput, reduced emissions, and potential carbon credits.

With these DI&M concepts in mind, Cherkassytransgas (CT) in Ukraine hired Indaco Air Quality Services to sur-

METHANE LEAK SCREENING AND MEASUREMENT TECHNIQUES

Table 4

Instrument-technique	Application and usage	Approximate capital cost
Soap solution	Survey of small point sources, such as connectors	$124-619
Electronic gas detectors	Survey of flanges, vents, large gaps, and open-ended lines	Under $1,238
Acoustic-ultrasound detectors	Survey of all components, including larger leaks and inaccessible components	$1,238-24,764
Flame ionization detector	Survey of all components	Under $12,382
Infrared leak imaging camera	Survey of all components, including inaccessible components	$73,000
Rotameter	Measurement of very large leaks	Under $1,238
Hi Flow Sampler	Measurement of most accessible components with leak rates below 326,000 cu m/day	Under $12,382
Bagging	Measurement of most accessible components	Under $12,382

Source: US EPA Natural Gas STAR recommended technologies and practices (www.epa.gov/gasstar/techprac.htm)

vey two of its compressor stations. Indaco's survey used catalytic oxidation and thermal conductivity detectors combined with soap solution to identify 280 leaks. Each emission was quantified with the Hi Flow Sampler, and the total methane emissions rate was over 2.8 million cu m/year. Recognizing these results as a product loss and potential market commodity, CT prioritized repair work, ultimately repairing 227 of the 280 emissions sources to save 1.9 million cu m/year. Nonrepaired emissions include leakage from compressor unit valves and blowdown valves. Methane savings were confirmed with post repair measurements. Survey, measurement, repair, and training required an investment of $7/tCO_2e/year saved. In addition, CT expects to gain additional revenue through exchanging carbon credits with a Canadian buyer for another $160,000/year over the course of 10 years.[5]

The Kursk Natural Gas Distribution Co. (Kurskgas) in Russia also identified methane leaks as an opportunity. Kurskgas retained Heath Consultants to survey 47 regulator stations in November 2005. Using catalytic oxidation and thermal conductivity detectors, Heath surveyed 1,007 components and discovered 94 leaks—90 from valve stem packing, 3 from pressure relief valves, and 1 from a flange. Using the Hi Flow Sampler, Heath quantified all leaks and reported a total methane emissions rate of over 900,000 cu m/year.

Following the survey, Kurskgas and Heath began a pilot effort to replace leaking stem packing in seven valves. Worn packing on each valve was replaced with W.L. Gore & Associates Inc. valve stem packing for a total material cost of $7. Leak reduction was immediate, and validation measurements confirmed that each leak was reduced to a level below detection.

The initial Kurskgas investment was $30,000, or $2.40/tCO_2e/year, assuming that all leaks were repaired. Positive initial results prompted Kurskgas to expand the initial 47-station study into a survey, measurement, and repair campaign across more stations, covering over 3,300 components.

The project was the first leak survey in Russia meeting eligibility requirements for joint implementation under the Kyoto Protocol, meaning that it produces revenue in the form of verified carbon credits.

Global project potential

Even with the industry's application of these methane emission reduction technologies and practices, there are still profitable opportunities for the oil and gas industry throughout the world. Fig. 2 represents methane emissions-reduction project potential in the five countries discussed in the case studies. Each country is represented by a marginal abatement cost curve showing cumulative emissions reduction potential on the x-axis and the reduction cost on the y-axis. The curves are based on methane emissions shown in Table 1, mitigation project options such as those identified by Table 2, and a discounted cash flow analysis using a 10% discount rate.

The reduction cost is also a project's breakeven value. Because methane is valued differently depending on its use and the local market, the breakeven value can be reached in a variety of ways such as end-use sales revenues, operating cost savings, or carbon credit sales. The curves for each of the five countries show that a significant fraction of emissions reductions are achievable at values under $5/tCO_2e.

The country curves provide a high level view of methane emissions reduction potential and the cost tiers of proven mitigation options. As expected, countries such as Russia with more-extensive oil and gas infrastructure have more potential reductions than countries such as Colombia having less infrastructure. All countries have oil and gas infrastructure to some degree, and countries with growing energy demand, production, and transmission are expected to increase methane emissions significantly through 2015, based on the EPA outlook. Fig. 3 shows similar curves for several key nations rapidly developing a more-extensive oil and gas infrastructure, such as China, India, Uzbekistan, and Venezuela. For these countries—as with any country—developing new infrastructure using best practices in methane emissions management is essential to environmental stewardship as well as project economics.

While the country curves indicate that potential exists in many regions, achieving results requires companies to identify the emissions and invest in the proven technology. TransCanada Pipelines has achieved over 2 million tCO_2e/year savings over the last 10 years through projects such as leak surveys, low-emission compressor seals installation, and blowdown avoidance. A three-tier approach effectively translated emissions management into emission reductions. First, senior leadership provided strategic direction and approved

projects to align with business needs. Second, program management measured progress on existing work and oversaw research on new mitigation options. Third, the execution and monitoring of these projects logged performance data that allowed for continuous improvement.

Pemex currently is well under way with a similar initiative to identify, measure, and capture methane emissions across its entire oil and gas infrastructure. The technologies and strategies Pemex and TransCanada are using and case studies of many other global oil and gas operators are available to any company or investor online through EPA's Natural Gas STAR web site.[6]

Global partnership

One successful initiative for decreasing emissions to increase revenue is Methane to Markets—a partnership comprising 20 nations focused on the goal of implementing the project types shown here. The role of the Methane to Markets Partnership is to bring organizations together with international governments to stimulate development of methane mitigation projects. Under this framework, US EPA launched Natural Gas STAR International, a partnership with oil and gas companies. About 120 oil and gas operators around the world participate in Natural Gas STAR, voluntarily advancing the recovery and use of methane as a valuable clean energy source.

The private sector, the research community, development banks, and other organizations also collaborate to execute such methane-saving projects (www.methanetomarkets.org).

An upcoming Methane to Markets Project Expo in October in Beijing, China, will bring together oil and gas operators and other stakeholders to combine resources and knowledge for profitably harnessing methane emissions.

Further information on the technologies discussed in this article can be found at EPA's methane emissions-containment web site (www.epa.gov/gasstar/techprac.htm). ✦

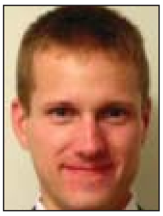
References

1. Natural gas valued at 25¢/cu m ($7/Mcf).

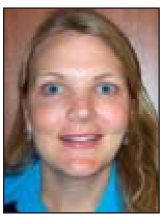
2. Fernandez, Roger, Lieberman, Daniel, and Robinson, Don, "US Natural Gas STAR program success points to global opportunities to cut methane emissions cost-effectively" (OGJ, July 12, 2004, p. 18). See also OGJ, Sept. 2, 2002, p. 22.

3. US EPA worldwide methane emissions estimate ("Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020," June, 2006, Appendix B-1) divided by EIA worldwide dry gas production estimate (www.eia.doe.gov/emeu/international/gasproduc-

The authors

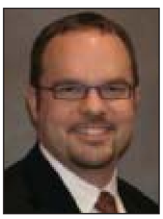


Brian Gillis, an associate at ICF International, has developed greenhouse gas emissions inventories for public and private sector clients ranging from site evaluations to country-wide estimates. His inventory work includes first-principles engineering studies to quantify greenhouse gas emissions. He is a developer of ICF's proprietary greenhouse gas emissions management system, which inventories greenhouse gas emissions and evaluates the economics of control options. Gillis also has contributed to laboratory and field-based performance analyses of infrared remote sensing technologies to identify emissions from oil and gas equipment. For Natural Gas STAR, Gillis provides support on identifying and mitigating methane emissions from specific industry processes.



Suzie Waltzer (waltzer.suzanne@epa.gov) is a member of the US EPA's climate change division and is a program manager for EPA's Natural Gas STAR Program. She promotes the implementation of cost-effective operational efficiency improvements and technologies to reduce methane emissions from oil and gas operations. Previously Waltzer worked with EPA's clean air markets division managing air quality and ecological assessments to evaluate the effectiveness of regional and national market-based emission control programs. Waltzer earned her master's degree in environmental management from Duke University.

Milton W. Heath III manages the methane emissions measurement programs at Heath Consultants Inc. These programs have been used to determine cost-effective maintenance strategies for leak reduction and to recover gas lost through leakage. As part of these efforts, Heath has developed and manages training programs for industry personnel, making it possible for gas companies to acquire the necessary technology and skills to screen and measure methane emissions at their facilities. Heath earned a BS from the School of Natural Resources and Environment at the University of Michigan.



Jim Cormack works for TransCanada as an advisor on climate change and air emissions issues. He helps develop TransCanada's climate-change policy, develops risk mitigation strategies related to air emissions for the company, and assesses financial risk to its assets arising from climate-change policy. Since 1996 Cormack has worked within the pipeline system design and operations groups. In 2004 he became an advisor on climate change and air quality issues. Prior to joining TransCanada, Cormack worked in plant process operations at various facilities, including oil refineries and gas processing plants. He chairs the Canadian Energy Partnership for Environmental Innovation and is a member of the Canadian Energy Pipeline Association's climate change task group, the Canadian Gas Association's air management subcommittee, and the Interstate Natural Gas Association of America's committee for environment, health, and safety as well as the greenhouse gas task force.

Krish Ravishankar is worldwide director of environmental affairs for Occidental Oil & Gas Corp. in Houston. He has over 20 years' experience and has worked with upstream and downstream energy industries and the power sector, consulting organizations, and international agencies such as the World Bank, East-West Center, Asian Development Bank, and International Finance Corp. He has published two books and numerous articles in international journals. He holds a bachelor's degree in engineering and three masters' degrees in development economics, resource economics, and environmental science.

tion.html).

4. US EPA, "Options for reducing methane emissions from pneumatic devices in the natural gas industry" (www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf).

5. Reducing Methane Gas Leaks at Cherkassytransgas (www.rec.org/ecolinks/bestpractices/PDF/ukraine_cherkassy.pdf).

6. US EPA Natural Gas STAR recommended technologies and practices (www.epa.gov/gasstar/techprac.htm).

US House passes energy bill amid Republican protest

Nick Snow
Washington Correspondent

The US House of Representatives passed a pair of energy bills Aug. 4 that Democrats said would greatly accelerate energy efficiency and alternative development efforts. Republicans charged that the measures are mislabeled because they would place additional limits on currently available resources, drive energy costs higher, and produce no new domestic supplies.

"Plainly put, the so-called energy bills before us tonight contain not a single watt of new energy—and worse, actually seek to lock away the scarce resources we have available right now," maintained Republican Whip Roy Blunt (Mo.). HR 3221 passed by 241 to 172 votes and heads to conference with the Senate. A companion measure, HR 2776, which contains taxes and other revenue-raising actions to fund new energy initiatives, was passed by 221 to 189 votes separately and combined with the larger bill.

The administration immediately announced that senior advisers would recommend that President George W. Bush veto the legislation in its current form. US Energy Secretary Samuel W. Bodman said the bill "actually will lead to less domestic oil and gas production and increase dependence on imported oil."

House Republicans indicated they have enough votes to sustain a veto. "This bill isn't going anywhere," said Joe Barton (R-Tex.), the Energy Committee's ranking minority member, who added that he was not even sure there would be an attempt to conference the bill with the other body.

Floor debate was delayed by a day on Aug. 3 as Republicans protested the manner in which a vote to recommit the farm bill was handled the night before and technicians tried to repair a vote display system malfunction. Members returned ready to tackle the energy bills on Aug. 4.

Roan Plateau language

HR 3221 retained language that Colorado Democrats John Salazar and Mark Udall persuaded the Rules Committee to insert that would prohibit surface activity on the Roan Plateau near Grand Junction if the US Bureau of Land Management issues leases there. They said this was a compromise because it did not ban leasing entirely, but other members and oil and gas and consuming industry groups said it effectively would lock up 9 tcf of natural gas.

The bill also kept provisions that Udall promoted from HR 2337 that would impose new requirements for handling produced water, delay oil shale leasing authorized under the 2005 Energy Policy Act, and expand surface land holders' rights in split-estate situations involving the federal government.

Also retained in the main bill were provisions requiring the US Minerals Management Service to conduct at least 550 oil and gas lease audits annually and requiring holders of Gulf of Mexico deepwater leases erroneously issued without price thresholds in 1998-99 to renegotiate terms or be barred from future lease sales.

The final bill also contained provisions from HR 2776 that would deny a general manufacturing tax deduction to oil and gas companies, move geological and geophysical cost amortization for certain major oil companies back to 7 from 5 years, and rewrite the foreign tax credit for US oil and gas companies.

As Democrats emphasized the bills' provisions dealing with alternatives and efficiency, Republicans said the measures would unfairly penalize traditional energy sources.

"There's a war going on against fossil fuels and I don't know why," said Ralph M. Hall (D-Tex.), chief minority member of the Science and Technology Committee. He said it makes no sense to punish the oil and gas industry, hinder the nuclear power industry, and refuse to develop clean coal. "We need to develop new technologies, but it's not going to happen next year or in 10 years."

Industry reactions

Oil and gas industry associations immediately condemned the legislation. The American Petroleum Institute called it "the wrong prescription for a secure energy future. It would discourage production of the energy Americans must have to maintain a thriving economy with strong job creation and improving living standards."

Independent Petroleum Association of America Pres. Barry Russell said, "The House energy bill ignores the stark reality that by 2030, oil and gas are projected to account for more than 60% of America's total energy mix."

Independent Petroleum Association of Mountain States spokesman Jon Bargas added, "It's especially harmful to the thousands of small, independent energy producers who drill 90% of the wells in the US and produce 82% of the nation's natural gas."

National Petrochemical & Refiners Association Executive Vice-Pres. Charles T. Drevna warned, "These bills turn back the clock by raising taxes on America's oil and gas industry, imposing onerous fees and additional restrictions on domestic energy production, and threatening to halt domestic production by nullifying existing contracts. Such policies will drive energy production and petrochemical businesses overseas." ✦

Analyst sees end to Iranian gasoline crisis by 2012

Iran's potentially destabilizing shortage of gasoline will ease by 2012, according to a veteran observer of the country's oil industry.

Fereidun Fesharaki, chairman and chief executive officer of FACTS Global Energy, says additions to refining capacity totaling 705,000 b/d during 2008-12 will eliminate Iran's strong reliance on imported gasoline. The capacity additions include three condensate splitters with 55% gasoline yield at Bandar Abbas.

With demand for gasoline, which is heavily subsidized, rising at 10-11%/year recently, the Iranian government in May increased prices of the product by 25% and in late June imposed rationing. The latter move caused riots in major cities (OGJ, July 9, 2007, p. 17).

In a report this month, Fesharaki says the government is under pressure to raise the price of gasoline sold beyond ration limits to international levels, about five times the current price, by September.

Following the government crackdown in May and June, he adds, smuggling of about 40,000 b/d of gasoline out of the country ceased. Iranian gasoline now is being smuggled to Iraq.

Last year, the Islamic republic imported about 192,000 b/d of gasoline. In the first week of May, Iranian gasoline demand averaged 496,000 b/d.

Fesharaki expects Iran eventually to export 100,000-250,000 b/d of gasoline while fuel oil exports drop to 50,000 b/d in 2012 from 250,000 b/d in 2006 once planned refinery projects are complete.

The analyst projects additions to crude distillation capacity by 2012 of 80,000 b/d at Arak, a total of 420,000 b/d at Bandar Abbas, 120,000 b/d at Isfahan, 50,000 b/d at Tabriz, 21,000 b/d at Lavan, and 14,000 b/d at Shiraz. He forecasts additions of processing capacities related to gasoline, such as catalytic cracking, catalytic reforming, and pentane-hexane isomerization, at those and other refineries.

Upstream work

Fesharaki notes a series of delays and cost overruns in major oil field development projects related to the buyback contracts under which foreign partners must work and to inefficiencies in the Iranian regulatory system.

Despite modest changes to the buyback contracts, he says, terms remain unattractive by international standards.

Furthermore, because of US pressure and political instability, international banks won't back Iranian energy projects. Last year, Iran produced 4.07 million b/d of crude and condensate from capacity estimated at 4.3 million b/d. Recent production gains have mostly been condensate from offshore South Pars field.

Production-decline rates are about 8%/year onshore and as high as 13%/year offshore. Despite the steep production declines and problems with oil field development, Fesharaki expects crude and condensate production capacity to reach 4.7 million b/d by 2012, almost all from South Pars.

Although Iran's gas reserves estimate of 993 tcf is second only to Russia's, the analyst sees a ceiling of 20-30 million tonnes/year on Iranian gas exports via LNG and pipeline.

He cites domestic demand kept high by subsidy pricing, oil field needs for gas injection of about 10 bcfd, large gas-based petrochemical projects, the use of compressed natural gas to supplement gasoline supplies, and political opposition to gas exports (OGJ, May 9, 2004, p. 34). ✦

API: US gasoline production, demand break records

Nick Snow
Washington Correspondent

US gasoline production and demand broke records during this year's first half despite higher prices and several unplanned refinery breakdowns, the American Petroleum Institute reported on July 18.

Gasoline production rose 3.4% year-to-year to an average 8.9 million b/d during the period, API said in its latest monthly statistical review. Gasoline imports, which had lagged during this year's first 3 months, rebounded to a record average of 1.3 million b/d during the second quarter, it indicated.

Higher imports aided total gasoline deliveries—which API uses to measure demand—to climb 1.5% to an average of 9.2 million b/d from 9.1 million b/d during the first half of 2006, API said. June's gasoline production hit a record monthly peak of 9.3 million b/d, helping to push the month's total gasoline deliveries 3.7% higher year-to-year to an average of nearly 9.8 million b/d from 9.4 million b/d a year earlier.

Demand for other products also broke first-half records. Distillate fuel oil demand climbed 1.9% year-to-year to an average 4.3 million b/d as deliveries of ultralow-sulfur diesel climbed 9.1% to an average of 3.3 million b/d. "The industry produced record amounts of products despite unplanned refinery outages. Overall, US petroleum deliveries were up 1.3% in the first half compared to a year ago," Ronald J. Planting, API statistics manager, told reporters during a teleconference.

Refining activity

Domestic refinery activity during the first half, as measured by input to crude distillation units, decreased 0.4% year-to-year to an average of 15.3 million b/d from nearly 15.4 million b/d during the first half of last year. API traced this to lower input levels during May and a counter-seasonal drop in June. The capacity utilization rate declined 1.1% to 87.6% as total operable capacity rose 0.8% to 17.5 million b/d.

API chief economist John C. Felmy said scheduled and unplanned refinery outages were higher than normal during this year's first half. "The planned outages were for operating reasons. But there is evidence that some of the unplanned shutdowns may have been a result of strain that was put on the system from reducing sulfur levels for ultralow-sulfur diesel," he said.

Tighter supplies initially increased gasoline prices, which dampened demand early in the second quarter, he continued. By June, however, lower prices helped restore demand as summer driving season got under way.

Felmy said gasoline prices overall rose during the first half but not enough to significantly affect demand. "For the year-to-date, retail gasoline prices averaged $2.70/gal. A year ago, they were $2.62[/gal], about 8¢ lower. That small a difference is not inconsistent with seeing an overall growth in demand for gasoline due to improved incomes and other factors. A 3% increase in price, all other things being equal, would only result in a 0.3% decrease in demand, which could easily be offset by the economy and demographics," Flemy said.

Upstream, domestic crude and condensate production in the first half grew 1.3% to 5.2 million b/d as production of natural gas liquids increased 0.5% to an average of 1.7 million b/d. Production increases in the Gulf of Mexico offset a 5.2% decline in Alaska, API said. ✦

BP to revamp company after disappointing earnings

Uchenna Izundu
International Editor

BP PLC must improve its operational performance to boost its profits, said BP Chief Executive Tony Hayward, at a press conference in London to present the company's second-quarter results.

Hayward, who was appointed to the role in May, admitted that BP's operational performance "is not good enough." He said, "The absolute numbers are large, but on most key measures our competitive performance in the first half was disappointing."

Hayward is determined to enforce change by yearend and build on the momentum in 2008. The company has suffered delays in major projects coming on stream and outages at its US refineries, which have contributed to poor performance.

BP produced 3.8 million boe/d in this year's second quarter, which was 5% lower than last year. The E&P segment made $6.5 billion in profit compared with $7.3 billion for the same period in 2005. BP attributed the fall to lower production volumes, increased integrity spend, and higher costs.

No change was made to the production guidance which remains at 3.8-3.9 million boe/d for 2007.

New Hayward agenda

Hayward is keen to turn around the company's safety culture following the critical report issued by the Baker Panel, which investigated the fire and explosion at its 460,000 b/d Texas City, Tex., refinery that killed 15 people and injured 180 others (OGJ Online,

Mar. 26, 2007). "We are implementing the Baker Panel recommendations," Hayward said. Furthermore, he said, the company will implement a group-wide operating management system that will improve the capability and consistency of its operations.

The benefit of the training program is to establish a common management system across the group, he explained. BP's previous internal program 'Getting HSE right' is being revamped to address process safety, which had been identified as a major omission in BP's safety culture under the Baker Panel report.

Developing people is also another priority under Hayward's tenure. He has launched an initiative that will see 100 people—25% of BP's staff in its London headquarters—redeployed in the field. These will be planners who will go back to petroleum engineering. The emphasis, for BP, is to "have the right people in the right place—and keeping those people in position longer."

Hayward admitted that a lack of in-house engineering experience was a major reason behind the problems with Thunder Horse field in deepwater Gulf of Mexico.

BP is retrieving and rebuilding all seabed production equipment after tests showed metallurgical failure (OGJ Online, Sept. 16, 2006).

Andy Inglis, head of exploration and production, said Thunder Horse is on track to start up by yearend 2008. "We are making good progress against this target," he said.

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.

Refinery focus

Revenues will be restored by bringing the refineries in the US back to capacity and starting up major projects, Hayward said.

The 405,000 b/d Whiting refinery is expected to return to full capacity in the first half of next year, BP said. "Repairs are ongoing and we expect to resume sour crude processing in the fourth quarter of 2007." BP refineries at Carson City, Texas City, and Toledo also had unplanned maintenance stoppages and production problems, causing the company to lose out on refining opportunities when margins are at an all-time high for the industry.

BP's refining and marketing section increased profits by 48% to $2.7 billion this quarter, including a gain of $770 million for nonoperating items, mainly related to Coryton disposal gains, said Chief Financial Officer Byron Grote. The company said it is confident it can improve the performance of its refinery portfolio.

Rising industry costs

However, Hayward added that increasing industry costs in the supply chain and higher depreciation charges will likely lessen BP's earnings. Industry costs are rising at 10%/year "with expenses a bit less and capital a bit more," according to Hayward. BP will manage industry costs through standardization of designs, standardized equipment lists, and a focus on continuity and consistency.

"We want to take standardized designs that are repeatable," he said. "We have done this in Azerbaijan and Trinidad and want to do this in Egypt and Angola." Hayward explained that building a standardized equipment list meant using a limited number of components that could fit into its design. As for continuity and consistency, he said the company had seen a dramatic learning curve in handling key infrastructure projects. ✦

CRE sees no massive shift to open natural gas markets

Doris Leblond
OGJ Correspondent

The July 1 opening of gas and electricity markets in Europe jumped to 12 million from 680,000 the number of French customers who can select their gas suppliers, but the Energy Regulatory Commission (CRE) foresees no massive shift to the open market.

CRE Pres. Philippe de Ladoucette said expansion will be slow because the market is concentrated in the hands of historic suppliers Gaz de France, Total SA, and Electricite de France. In addition, government regulated tariffs available to all consumers compete successfully with market prices.

France imports 98% of the gas it consumes, mainly under long-term supply contracts hitched to the price of oil products. For consumers to fully benefit from an open market, more efficient and transparent price signals are needed that reflect the medium and long-term investments required to increase production and network infrastructures.

CRE insists development of interconnections and new points of entry for gas imports are indispensable to help new entrants gain access to the French market. New tariff proposals that became effective at the start of this year are providing inducements for investment in the transport network. These tariffs are adapted to the specific features of two network operators, GDF's subsidiary GRTgaz (Gestionnaire de Reseau de Transport) and Total's TIGF (Total Infrastructure Gaz France) that together control 89% of gas imports into France, 83% for GDF and 6% for Total.

CRE said LNG could become a significant alternative with five methane terminals to be commissioned by 2011-12 by competitors of GDF and Total.

European cooperation

A large part of France's gas supplies transit through European countries, so CRE has closely cooperated with the European Regulators Group for Electricity and Gas (ERGEG). Because of its geographic position, France is part of two of the three regional initiatives that would be forerunners of a single EU energy market. The Northwest initiative includes Germany, Belgium, Denmark, France, the UK, Northern Ireland, Ireland, the Netherlands, and Sweden, which have formed six working groups to deal with cooperation among regulators, quality of gas, transparency, balancing and hubs, and interconnections.

CRE and its German counterpart Bundesnetzagentur together chair the working group dealing with interconnections and primary gas transport capacities. Priority is given to Taisnieres on the France-Belgium border and Obergailbach on the France-German border.

The South regional initiative includes France, Spain, and Portugal but so far is restricted to the two first countries.

Watching the World

Eric Watkins, Senior Correspondent

Russian subs and arctic oil

Money, they say, is the root of all evil, but these days a lot of evil is being committed in the name of oil. Consider Russia, an oil-rich nation bent on taking over the Arctic.

Its oil income, nefariously out of private hands and back under government control, is funding a new militarism, and that, in turn, is being used to acquire even more oil wealth.

Recent reports say Russia is ready to start production of a new submarine-based intercontinental ballistic missile that will form the core of the country's seaborne nuclear arsenal.

According to the commander of the Russian Navy, Admiral Vladimir Masorin, a recent successful test of the Bulava-M missile has paved the way for the start of production.

Missile system

"After the results of this, a decision was made to start [the] creation of the military base for the system, in other words, the serial production of parts for this new missile system," Masorin said.

The Russian navy said in June that a Bulava missile launched from a submarine in the White Sea hit its target 6,700 km away on the Kamchatka Peninsula in the Russian Pacific opposite Alaska.

That must be comforting news for Alaskans and others along the way such as the Japanese. And what does it mean? Well, it seems that the Russians want a new era aimed at dominating the rest of the world through military power.

If you doubt that, then remember that Russia recently sent two mini-submarines to the Arctic Ocean floor under the North Pole where they planted a titanium capsule containing the nation's flag.

The move symbolically claims almost half of the planet's northern polar region for the Kremlin. But it could be much more than mere symbolism.

Claiming the Arctic

In a perilous project mixing science, exploration, and the scramble for potential oil and gas fields, crews of the submarines engaged in what Russian authorities called the first dive to the ocean floor at Earth's northernmost point.

Russian scientists were to map part of the Lomonosov Ridge, a 1,240-mile underwater mountain range that crosses the polar region. The ridge was discovered by the Soviets in 1948 and named after a famed 18th Century Russian scientist, Mikhail Lomonosov.

In December 2001, Moscow claimed the ridge was an extension of the Eurasian continent and therefore part of Russia's continental shelf under international law. The United Nations rejected Moscow's application, citing lack of evidence, but Russia plans to resubmit it in 2009.

If recognized, the claim would give Russia control of more than 1.2 million sq km, representing almost half of the arctic seabed. Little is known about the ocean floor near the pole, which might overlie vast oil and gas deposits.

And if not recognized? Well, why do you think the Russians are investing so much of their new-found oil wealth in submarine-launched missile systems? ✦

New capacities are needed because of expected increased gas trade between France and Spain. But at this stage, Spain is capturing some of the gas that flows between Spain and France. A second gas line to link France with Spain's Bilbao LNG terminal is being built by TIGF in joint venture with Spain's Gas de Euskadi. Called Escadour, it is due on stream in the fall of 2008 and is intended to increase the capacity of Total's Lussagnet storage facility.

TIGF, Enagas, and GRTgaz also worked out a joint and broader investment program for French and Spanish gas connections at the points where they meet.

At Larrau, from France to Spain, annual capacity is to increase from 2.9 billion cu m to 6 billion cu m in 2010-11. A 3.6 billion cu m/year capacity has already been decided to come on stream in 2009.

From Spain to France, an initial 3.6 billion cu m/year will be operational in 2010 and a potential 6 billion cu m extension in 2011 is under discussion. At Biriatou, a 400 million cu m extension to 2.2 billion cu m/year from France to Spain, and a 210 million cu m extension to 1.3 billion cu m/year from Spain to France is being proposed.

The third regional initiative covers South-Eastern Europe and includes Austria, Greece, Italy and Central European countries—Hungary, Poland, the Czech Republic, Slovakia, and Slovenia. ✦

PennEnergy
New & Used Equipment
WWW.PENNENERGY.COM

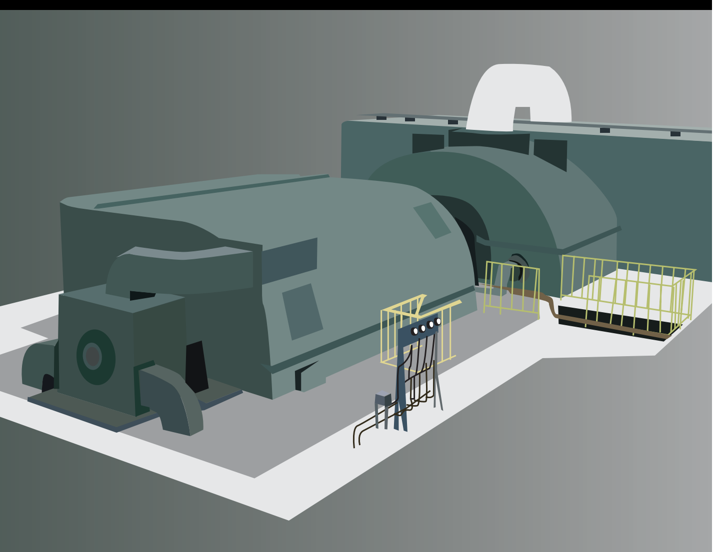
Our assets sell your assets.

Our global, multi-channel marketing reach means a faster sale for you.

PennEnergy is simply the easiest, fastest and most efficient way to sell new and used equipment to the global oil and gas, refining and petrochemicals industries. Why? Because the eyes of these industries are on us every day. We market your new or used equipment across the industry's most popular publications, high-traffic web resources, and relevant databases – ensuring your offer reaches every possible potential buyer. The proof? More than one-half billion dollars in energy equipment transactions over five years.

GET
GLOBAL EQUIPMENT TRACE

Power generation equipment available for immediate delivery



Offered by Thomassen Amcot Development LLC and available exclusively through PennEnergy

- New and unused Model K36-13; N36-2X5.6 142-MW Fuji steam turbine generator set now available for immediate sale and delivery.
- Unit is a double flow, reheat, admission, condensing STG.
- Unit is stored in Las Vegas, Nevada.
- Unit is currently shrink-wrapped and stored according to manufacturer's specifications.

THOMASSEN AMCOT DEVELOPMENT LLC

Contact

For info or pricing

Paul Westervelt at PennEnergy – Blackberry and Email: pwestervelt@pennenergy.com | P: 713-499-6305, or
Chris Davis at Thomassen Amcot Development LLC – Email: cdavis@thomassenamcot.com | P: 817-263-3271 | C: 817-296-1967

More operators eye Maverick shale gas, tar sand potential

Alan Petzet
Chief Editor-
Exploration

Gas potential in the overpressured Cretaceous Pearsall shale has drawn two of the world's largest oil and gas companies to South Texas and the Maverick basin, a province almost exclusively tended by smaller independents for the past few decades.

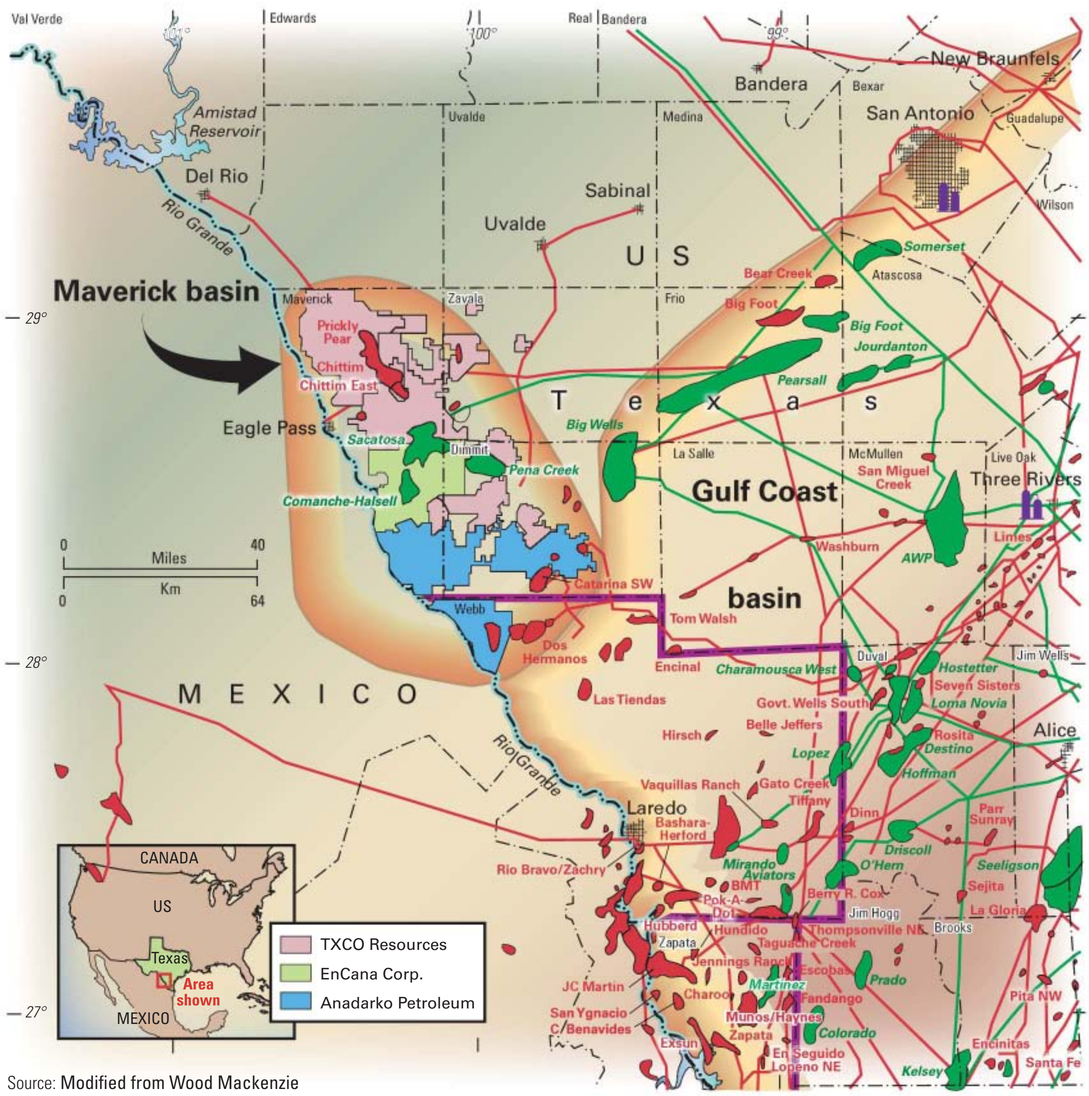
The new, well funded players EnCana Corp. and Anadarko Petroleum Corp. are almost certain to step up the basin's exploration and development pace, but how soon and to what extent are difficult to predict.

The basin's long-term host operator, TXCO Resources Inc., formerly The Exploration Co., is in various stages of developing only a few of the basin's 20 prospective formations, most of which produce in widespread parts of the greater Gulf Coast.

Besides the Pearsall shale, TXCO is mainly developing light oil in the Cretaceous Glen Rose formation and has just started a shallow tar sand pilot project. After years of operating almost solely in the Maverick, it has also begun to devote limited attention to other Midcontinent basins, including the Gulf Coast, Anadarko, and Marfa basins.

MAVERICK BASIN LEASEHOLD POSITIONS

Fig. 1



Source: Modified from Wood Mackenzie

Pearsall shale

EnCana, Anadarko, and TXCO all credit Pearsall shale gas prospects as the main reason for their entries into the Maverick basin.

TXCO and others have produced 20 bcf of gas from the Pearsall through 50 vertical wells, said James E. Sigmon, chief executive officer. This was before 3D seismic, underblanced drilling, advanced fracturing, or horizontal drilling were available.

Gas-fired steam generator and tank battery at TXCO Resources-Pearl E&P two-well tar sand pilot in Maverick County, Tex. Photo courtesy of TXCO.

Horizontal drilling and advanced completion techniques have the potential to turn the Pearsall into a predictable resource play across nearly all of the basin, TXCO said. The company holds more than 600,000 net acres on the Chittim anticline (see map).

To pursue the Pearsall, TXCO enlisted EnCana, which brings horizontal drilling and fracturing experience from the Barnett shale. TXCO gained acreage interests as part of the deal (OGJ Online, Feb. 21, 2007). EnCana has estimated that the Pearsall averages 900 ft thick and has 100-300 bcf/sq mile of gas in place. The companies budgeted to drill three Pearsall wells in 2007 and in July were attempting a completion in the lateral at the second well.

Anadarko, meanwhile, has leased 330,000 acres in the southern part of the basin and has estimated 950 tcf of gas in place in the Pearsall and shallow Eagle Ford sections combined.

Anadarko has drilled five vertical wells, and its drilling permits include at least one horizontal well.

Another independent, Cornerstone E&P Co., Irving, Tex., holds more than 190,000 acres, is targeting the Cretaceous and Jurassic intervals, and is completing its first vertical Pearsall well.

Tar sand

TXCO and Pearl Exploration & Production Ltd., Calgary, are conducting pilot tests of separate tar sand and heavy oil deposits in the northeastern Maverick basin 30 miles northeast of Eagle Pass.

The overall tar sand deposit has an estimated 7-10 billion bbl of 0° gravity hydrocarbon in place in Cretaceous San Miguel at 1,400-2,200 ft on 170,000 acres and 50 ft thick on 123,000 acres of that. The deposit is geologically similar to the larger one at Cold Lake, Alta.

TXCO and Pearl hold 36,000 acres of lease rights in a 68,000-acre area of mutual interest on the west side of the deposit, and TXCO has 100% interest in another 41,000 acres on the east side.

The companies are in the third steam cycle, alternately injecting steam in one of two 2,000-ft wells and producing from the other. The first two cycles raised the bottomhole temperature to 300° from 100°, and the second cycle briefly elicited 48 b/d of oil production. Optimum temperature is 400-450°, TXCO said.

The steam generator consumes 300-500 Mcfd of TXCO's produced gas.

A 16-well, 1,500-ft deep, coal-fired pilot is under design.

Produced tar is under analysis, and TXCO would mix it with Glen Rose crude to yield an 18-20° gravity blend.

The companies are evaluating three steam technologies: steam-assisted gravity drainage (SAGD) pioneered in Canada, fracture-assisted steam technology (FAST) employed successfully at Saner Ranch in Maverick County by Conoco Inc. in the 1980s, and cyclic steaming.

Just west of the tar sand deposit is an estimated 100 million bbl of 10-14° gravity oil in place in San Miguel on 6,000 acres in which TXCO has 100% working interest.

The company has drilled two 2,000-ft laterals 200 ft apart through the oil deposit 150 ft deep and back to the surface. Next it drilled five vertical wells

25-100 ft from the laterals to monitor heat propagation. A steam generator is on order.

Other plays

Total production from the basin has been increasing since 2004 on an oil-equivalent basis, with gas production by itself declining, noted Wood Mackenzie consultants.

TXCO and ConocoPhillips are the basin's two largest oil and gas producing companies.

Gas production has fallen in Prickly Pear field, but that has been partly offset by growth from TXCO and AROC (Texas) Inc. in Chittim East field.

TXCO also has a coalbed methane pilot in early stages in the Maverick basin (OGJ Online, Feb. 10, 2004).

TXCO reported oil sales from the Glen Rose porosity play (Comanche-Halsell field) were 168,425 bbl in the quarter ended June 30, up from 123,300 bbl for the first quarter. CMR Energy LP, Houston, also operates in the field.

TXCO said that its Maverick basin drilling in mid-July included five wells targeting the Glen Rose porosity play and one well each to the Pearsall, Georgetown, and Pena Creek San Miguel formations.

ConocoPhillips continues to develop Sacatosa (San Miguel) oil field, discovered in 1956. ✦

3D seismic guides Arkoma basin Fayetteville play

Drilling and 3D seismic surveying are ramping up in the Arkoma basin Fayetteville shale gas play in Arkansas.

Southwestern Energy Co., Houston, which held 1,400 sq miles of net acreage in the play as of June 30, has shot 145 sq miles of 3D surveys and expects to have 400 sq miles of 3D surveys by yearend.

The company, which plans capital spending of $950 million in the play this year, including gathering systems, will focus most of its development drilling in areas identified as "better performing" and with 3D seismic coverage. It also is forming a preference for slickwater fracs.

Southwestern's net Fayetteville shale production averaged 105 MMcfd in the first 6 months of 2007, and its gross operated production reached 200 MMcfd on July 28. That included 10 MMcfd from five wells producing from conventional reservoirs in four pilot areas.

As of June 30, Southwestern had drilled and completed 303 operated wells, 246 of which are horizontal. Of the horizontal wells, 219 were fracture-stimulated with slickwater or cross-linked gel fluids.

The wells are in 33 pilot areas in eight counties from Franklin County east to northwestern White County, largely east of the traditional Arkoma basin gas producing fairway. The company runs 19 rigs, including 15 capable of drilling horizontal sections.

Southwestern drilled and completed 62 operated Fayetteville wells in the quarter ended June 30. Excluding wells drilled vertically in new areas to gather reservoir data before horizontal drilling, they averaged $2.9 million/well, 2,550-ft laterals, and 18 drilling days.

Costs may increase as the company drills longer laterals, Southwestern said. Ten of the second quarter wells had laterals longer than 3,000 ft.

One well, Bartlett 2-27 in the South Rainbow pilot area, had a 3,700-ft lateral, flowed 4.4 MMcfd after an eight-stage slickwater frac, and was making 4 MMcfd on July 21 after being on production 25 days.

The last 10 wells Southwestern completed using slickwater fluids have averaged initial rates of 2.6 MMcfd, and three exceeded 4 MMcfd. One of those, Reaper 1-12 in the Bull pilot area, which had a 2,000-ft lateral and a four-stage completion, made 4.6 MMcfd, the company's highest daily rate to date.

Southwestern's Fayetteville play position includes 699,000 undeveloped acres, 76,000 net acres held by Fayetteville shale production, and 125,000 net acres held by conventional production. ✦

Algeria

A group led by Repsol YPF SA has found gas in an Ordovician formation in the Reggane-6 (RG-6) appraisal well on block 351c and 352c in Algeria's Sahara Desert.

The well was drilled to a TD of 5,116 m and the "discovery in this geological formation adds to the Reggane North region's gas reserves," said RWE Dea, a partner in the group.

Feasibility studies are under way, and it is not yet known when development drilling will start, RWE told OGJ.

This is the fourth well to encounter gas on the Reggane North concession (OGJ Online, May 18, 2006).

Other participants in the blocks that span 8,566 sq km are Edison International and Sonatrach.

Ghana

A group led by Anadarko Petroleum Corp. as technical operator plans to drill the Hyedua exploration well on the Tano Deep Block off Ghana, spudding in mid-2007.

The well follows the Mahogany-1 discovery in 4,330 ft of water on the adjacent West Cape Three Points Block. Mahogany cut 885 ft of gross hydrocarbon column with 312 ft of net stacked

pay in a Cretaceous sandstone reservoir (OGJ Online, June 19, 2007).

Meanwhile, Anadarko 40%, Kosmos Energy LLC 40%, and Petronas 20% plugged the Sota prospect in Block 4 off Benin after drilling to TD 12,500 ft in 6,700 ft of water.

India

India's Directorate General of Hydrocarbons let a contract to GGS-Spectrum, Oslo, to reprocess as much as 12,000 line-km of 2D seismic surveys off India's west coast and to license the results to third parties in connection with a licensing round.

The survey area covers blocks that are to be included in the NELP VII licensing round expected to open in the third or fourth quarter of 2007 and close in the first quarter of 2008.

GGS-Spectrum will apply state of the art processing including multiple attenuation techniques, prestack time migration, and prestack depth migration.

Netherlands

Cirrus Energy Corp., Calgary, plans to develop M1-A field in the Netherlands North Sea.

Most likely reserves from the single well are 35 bcf from 93 bcf of proved and probable gas in place in overpressured, low-permeability Triassic-aged sandstones at 3,900 m.

Cirrus is operator with 47.5% working interest. Its partner is the state owned company EBN. The development budget is $53.3 million.

The development plan involves reentry and hydraulic fracture stimulation of the suspended M1-3 well with subsea completion and tie-back to existing gas processing and export infrastructure. First gas is expected in the fourth quarter of 2008 at 10-14 MMcfd for the first year.

The license covers 212 sq km in 40 m of water. The field was discovered in 1992, and an appraisal well was drilled in 1998. Further development drilling may occur later to accelerate recovery of what may be 230 bcf of gas in place or more.

Russia

Siberian Energy Group Inc., New York, is investing $16 million in Western Siberia, where it holds seven licenses that total more than 1 million acres in Russia's Kurgan area bordering central Kazakhstan and Russia's Tyumen Region.

The first well on the Privolny license, designed to correlate with seismic and geochemical data, reached 7,892 ft and was cored in the Middle Carboniferous-Moscovian and Upper and Middle Devonian sections. After analyzing the core, the company will decide whether to deepen the well.

The well provided sufficient data to spud the next exploration well on the adjoining Mokrousovsky license in September.

Four wells are planned overall, including Privolny-2 in the fourth quarter, all to 6,100-6,500 ft. The licenses, to be exploited consecutively, are near oil pipeline and rail infrastructure.

Alaska

The Colville River Unit containing Alpine field on Alaska's North Slope achieved a record oil production rate of 142,500 b/d on May 10, 2007, said 22% interest owner Anadarko Petroleum Corp.

ConocoPhillips has 78% interest and operates the field, which went on production in November 2000. The westernmost producing field on the slope, the unit was originally expected to recover 429 million bbl of oil.

Indiana

Western Pipeline Corp., Irving, Tex., said its Catt-1 oil discovery in Gibson County went on production Mar. 16, 2007, at 35 b/d of oil with small amounts of casinghead gas from 14 ft of pay.

The company said the project area produces oil and gas from channel and offshore bar sands, biocalcarenites, oolite shoals, and possibly from reef and dolomitic vugular porosity.

The Catt-1 completion will lead to several additional Mississippian Hardinsburg completions in the field, the company said.

New Mexico

Sun River Energy Inc., Wheat Ridge, Colo., plans a 20-well exploration program in 2007-08 for coalbed methane in the Raton basin in Colfax County.

That program is based on the results of three wells the company has drilled and cased to about 1,300 ft, all of which encountered multiple coals in the Raton and Vermejo formations. The company plans to frac the three wells in late July or August.

The 20-well program will fully explore the company's 12,000-acre position on 640-acre spacing.

Sun River noted that historical recovery averages for Raton basin CBM wells are 1 bcf for Raton coals and 1.6 bcf for Vermejo coals.

Texas

West-Central

Giant Petroleum Inc., Irving, Tex., and Hilltex Operating Co. have completed three of 20 wells they plan in Shackelford and Throckmorton counties, Tex.

Well 136-1, drilled into a Mississippian reef, tested more than 600 Mcfd of gas from a gas cap.

Well 137-1, also drilled into the reef, flowed on test at a rate of 125 b/d of sweet crude oil and 300 Mcfd of gas and has been placed on production.

The Miller-1 well targeted the Mississippian reef and Caddo limestone formations. The well had multiple shows and log indications in several pay zones in the wellbore. Giant Petroleum said the partners plan to recomplete the well uphole from a failed completion attempt in the Mississippian reef.

Petro-Canada updates Fort Hills oil sands costs

Guntis Moritis
Production Editor

Production

Petro-Canada expects the first phase of the Fort Hills oil sands project in Alberta to have a capital cost of $14.1 billion (Can.) and produce through mining 160,000 b/d of bitumen, which then the venture would upgrade to 140,000 b/d of syncrude.

In a June 2007 presentation, the company said the first bitumen production from Fort Hills should start in late 2011, pending final project approval, with the upgrader ready to process bitumen in second-quarter 2012.

The Fort Hills partners also plan a second phase in the venture that would double production and upgrading to 320,000 b/d of bitumen and 280,000 b/d of syncrude.

The present plans for the upgrader call for producing a single 36° gravity syncrude with less than 0.1% sulfur.

Both phases together have an estimated capital cost of $26 billion (Can.).

Working interest owners of the Fort Hills Energy LP project are Petro-Canada, 55%, UTS Energy Corp., 30%, and Teck Cominco Ltd., 15%.

Petro-Canada Oil Sands Inc., a unit of Petro-Canada, operates the project.

Fort Hills

Fort Hills is an integrated oil sands project that includes a mine and a bitumen extraction plant 56 miles north of Fort McMurray, as well as a bitumen upgrader about 300 miles south in Sturgeon County east of Edmonton. Fig. 1 shows the Fort Hills lease and future extraction-plant site.

FORT HILLS CAPITAL COSTS

Table 1

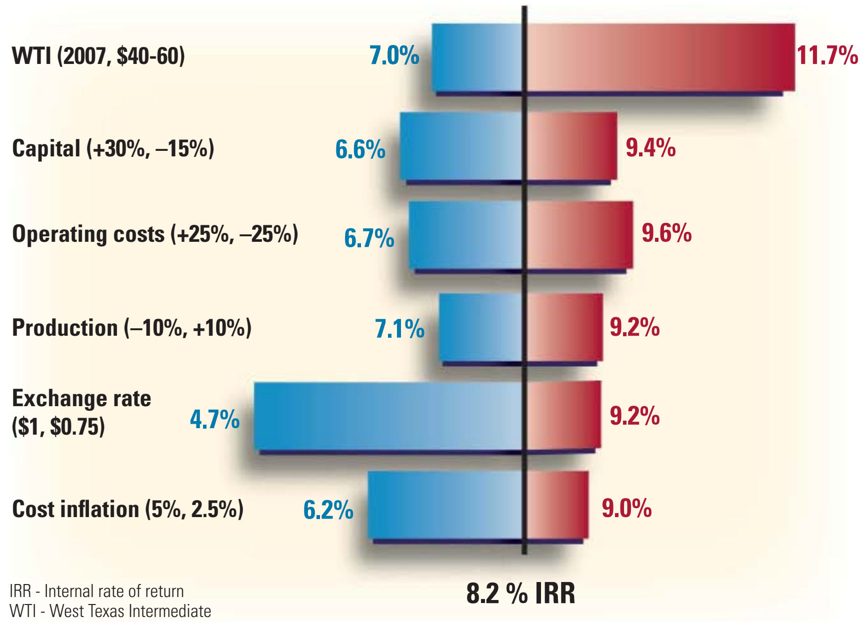
	Phase 1	Phase 2	Total
	Billion $ (Can.)		
Mining and bitumen production	6.0	6.1	12.1
Upgrading	5.1	4.3	9.4
Infrastructure	3.0	1.7	4.7
Fort Hills partner cost	**14.1**	**12.1**	**26.2**
FEED	1.1	0.8	1.9
Third-party capital	3.6	1.7	5.3
Full cost	**18.8**	**14.6**	**33.4**

Note: Costs are in dollars as spent.
Source: Petro-Canada

The Fort Hills lease, 56 miles north of Fort McMurray, Alta., is the site of a planned oil sands mine and extraction plant (Fig. 1). Photo from Petro-Canada.

IRR SENSITIVITIES

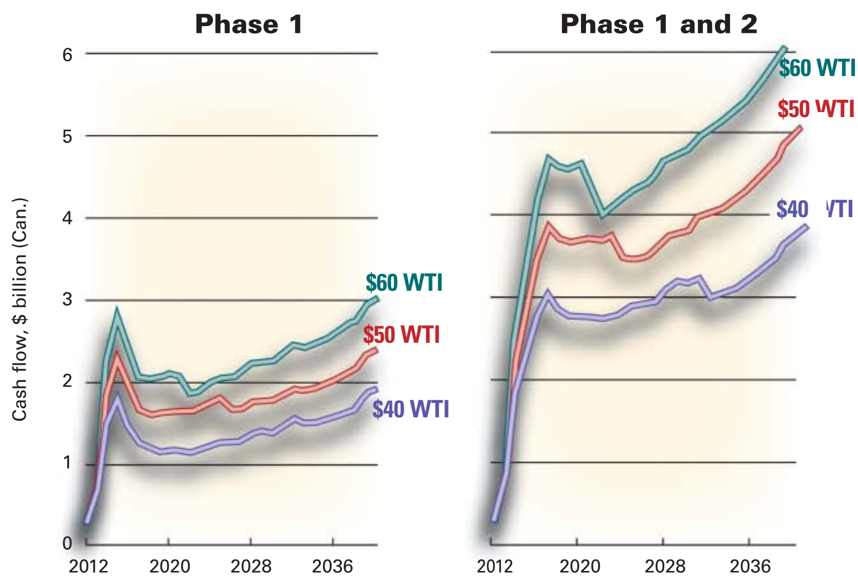
Fig. 2



IRR - Internal rate of return
WTI - West Texas Intermediate
Source: Petro-Canada

PROJECT CASH FLOW

Fig. 3



WTI - West Texas Intermediate
Source: Petro-Canada

Petro-Canada said the project currently is in the front-end engineering and design (FEED) stage that will take about 12 months to conclude. The company expects the FEED process to provide a definitive cost estimate and the basis upon which the Fort Hills partners will make the final go-ahead decision.

Regarding the FEED process, Ron Brenneman, Petro-Canada's CEO and president said "The size, staging, and technology chosen should provide solid financial returns while minimizing execution risk. This step puts us on a path for a final go-ahead project decision in the third quarter of 2008, following the anticipated regulatory approval of the Sturgeon Upgrader."

The Fort Hills mine received regulatory approval in 2002 from Alberta Environment and the Alberta Energy and Utilities Board. The partners filed the commercial application and environmental impact assessment for the Sturgeon Upgrader with provincial regulators in December 2006.

Table 1 summarizes the capital cost of both Phases 1 and 2.

The $14.1 billion (Can.) cost for Phase 1 includes a $1.7 billion (Can.) estimate for inflation during the next 4-5 years, while the FEED phase before sanctioning will cost another $1.1 billion (Can.).

In addition, the project also will need investments from third parties such as for the pipeline and return diluent line between Fort Hills and the Sturgeon upgrader, estimated to cost about $1.5 billion (Can.).

In Phase 1, other third-party investment includes hydrogen plants, co-gen plants, camps, and sulfur and coke handling. These additional investments increase the cost of Phase 1 to $18.8 billion (Can.).

Petro-Canada said Phase 2 will cost less because it will leverage investment made during Phase 1. Phase 2 capital cost for the partners is $12.1 billion (Can.). This includes an estimated $2.1 billion (Can.) for inflation. Expected start of production for Phase 2 is 2014.

Both phases include two trains for the mine but the upgrader investment for Phase 2 is less than for Phase 1. Phase 1 will have four coke drums, while Phase 2 calls for adding to the upgrader two coke drums, a vacuum column, another crude unit, and some additional hydrotreating.

Petro-Canada said that it staggered the mine and upgrader start-ups to avoid an overlap in manpower peaks during the construction. The mine starts up in 2011 and the upgrader starts 6-9 months later in 2012. Also, the partners plan to start Phase 2 at the tail end of Phase 1 and keep the same construction

Fort Hills economics

Table 2

WTI oil price, $/bbl	IRR Phase 1, %	IRR Phases 1 and 2, %
40	7.0	8.8
45	8.2	9.9
50	9.5	11.3
60	11.7	13.4

Assumptions:	
SCO price at Edmonton, $(Can.)/bbl in 2007	50
Natural gas price, $(Can.)/GJ in 2007	7
Exchange rate, $US/$(Can.)	0.80
Mine and extraction plant escalation, %	3.5
Upgrader escalation, %	2.5
Operating costs, $(Can.)/bbl in 2007	24
First bitumen production	Fourth-quarter 2011
First SCO production	Second-quarter 2012

Note: SCO—synthetic crude oil; IRR—internal rate of return; WTI—West Texas Intermediate.
Source: Petro-Canada

force, if the economics remain favorable.

The project includes a paraffinic froth treatment at the extraction plant that Petro-Canada said would allow the venture to sell marketable bitumen during the time between mine start up and upgrader completion.

Petro-Canada said the process involves removing paraffin at the mine site and then blending in a condensate to the bitumen for transporting the blend to Edmonton.

The project will include a diluent pipeline for returning condensate from the upgrader to the extraction plant.

Some of the engineering contracts in the FEED include:

• Technip Canada Ltd.—upgrader coker.

• SNC Lavalin Inc.—upgrader hydrotreating and tank farm, and mine froth treatment.

• CH2M Hill—upgrader water treatment.

• Washington Group International Inc.—upgrader utilities and offsites.

• Fluor Corp.—mine extraction plant.

• Jacobs Engineering Group Inc.—mine utilities, offsites, utility corridor, and tank farm.

• Hatch Energy—ore operations plant.

Fort Hills will design the tailings area and plans to award design of the upgrader sulfur plant in third-quarter 2007. During the winter of 2007, the project schedule includes drilling 300-400 wells to delineate additional resources on the lease.

Economics

Petro-Canada in the project base-case economics assumed a $45/bbl West Texas Intermediate (WTI) oil price. With this price, Phase 1 has an internal rate of return (IRR) of 8.2% (Table 2). Because of lower capital cost for Phase 2, the second phase has a higher 12.5% IRR at $45/bbl, which increases to 13.8% IRR at $50/bbl and an IRR greater than 16% at $60/bbl.

The tornado diagram (Fig. 2) shows that the IRR for Phase 1 ranges between 7-11.7% for oil prices between $40-60/bbl. Other sensitivities shown are for capital, operating cost, production, exchange rate, and cost inflation.

The operating cost central point assumes $24 (Can.)/bbl operating cost for both the mine and upgrader.

The exchange rate sensitivity is from $1.00 to $0.75 and shows that a strong Canadian dollar hurts the project economics.

The current exchange rate is about $0.93 US/$1 (Can.) while current oil prices are about $70/bbl.

Petro-Canada did not include the FEED costs in the economics.

Fig. 3 shows the substantial cash flow Petro-Canada expects the project to generate for three different WTI oil price scenarios. ✦

Indices describe complexity of drilling directional, extended-reach wells

Mark J. Kaiser
Center for Energy Studies
Louisiana State University
Baton Rouge

Drilling

Using indices to describe and compare drilling complexity and analyzing the efficiency of the energy applied to formations while drilling can improve performance.

The first part of this series reviewed the two main predictive models used to evaluate drilling costs in the US Gulf of Mexico: the joint association survey (JAS) and the mechanical risk index (MRI; OGJ, Aug. 6, 2007, p. 39).

This second part of the survey on drilling cost and complexity estimation models reviews the indices used to characterize the complexity of drilling directional and extended-reach wells: the directional difficulty index (DDI) and difficulty index (DI).

This article reviews the structural basis of the models and their underlying assumptions.

Recently, use of the concept of mechanical specific energy (MSE) in drilling workflows has improved bit efficiency and performance by identifying specific limiters and then reengineering the process. This article highlights advances in use of the MSE to manage and quantify the drilling process.

The final part of this series will present a new approach to estimating drilling costs that combines regression-based techniques as employed in the JAS with the multidimensional attributes of drilling, as incorporated in the MRI, DDI, and DI models.

Directional difficulty index

Schlumberger engineers proposed the "directional difficulty index" (DDI) to evaluate the difficulty in drilling a directional well.[1] Key performance

ESTIMATING DRILLING COSTS—2

measures were identified through a questionnaire and quantified with three drilling factors derived from four primary variables as shown in Equation 1 in the accompanying equations box.

Along-hole depth (AHD) is computed from an elliptical integral and the tortuosity (TORT) describes the total curvature of the wellbore. The primary parameters related to trajectory curvature are bending angle (dogleg angle) and borehole curvature. The multiplica-

EQUATIONS: DDI, DI, MSE

$$DDI = \log\left[TD\left(\frac{AHD}{VD}\right)TORT\right] \quad (1)$$

$$\delta: f_i \rightarrow \delta(f_i),$$
$$\hat{\delta}: f_i, f_j \rightarrow \delta(f_i, f_j) \quad (2)$$

$$\delta(NS/ECD) = NS/ECD, 0 < FG < 1.0$$
$$\delta(NS/ECD) = 2 \cdot NS/ECD, 1.0 \le FG \le 1.5 \quad (3)$$
$$\delta(NS/ECD) = 4 \cdot NS/ECD, 1.5 \le FG \le 2.0$$

$$DI = \sum_{i=1} \delta(f_i) + \sum_{i<j} \hat{\delta}(f_i, f_j) \quad (4)$$

$$MSE = \frac{480 \cdot Tor \cdot RPM}{DIA^2 \cdot ROP} + \frac{4 \cdot WOB}{DIA^2 \pi} \quad (5)$$

$$ROP = \frac{2,538 \cdot W}{MSE \cdot DIA^2} \quad (6)$$

$$TLROP = \frac{2,538 \cdot W}{TLSE \cdot DIA^2} \quad (7)$$

Nomenclature

DDI	=	Directional difficulty index
TD	=	Total depth of well, ft
AHD	=	Along-hole displacement, ft
VD	=	Total vertical depth, ft
δ(VD)	=	Vertical depth factor
TORT	=	Tortuosity, °
$\delta(f_i)$	=	A one-dimensional functional
$\delta(f_i, f_j)$	=	A two-dimensional functional
f_i	=	The ith factor of the drilling process, wellbore, or other descriptor
NS	=	Number of casing strings and liners below the drive casing
ECD	=	Equivalent circulating density
NS/ECD	=	String factor
FG	=	Fracture gradient factor, ppg
DI	=	Difficulty index
MSE	=	Mechanical specific energy, ksi
Tor	=	Torque
RPM	=	Revolutions/min
DIA	=	Diameter of the drillbit, in.
ROP	=	Rate of penetration, ft/hr
WOB	=	Weight on bit
W	=	Power input to drilling, hp
TLROP	=	Technical limit rate of penetration, ft/hr
TLSE	=	Technical limit specific energy, ksi
STW	=	Smallest target width, ft
DOG	=	Dogleg, °
MXMW	=	Maximum mud weight, ppg
MXMW/O	=	Maximum mud weight oil-based, ppg
U	=	Underbalanced drilling mode
T(TD)	=	Bottomhole static temperature, °F.

Vertical depth

Table 1

δ(VD)	VD, ft
0	VD < 8,000
1	8,000 ≤ VD < 10,000
2	10,000 ≤ VD < 12,000
3	12,000 ≤ VD < 14,000
4	14,000 ≤ VD < 16,000
5	16,000 ≤ VD < 17,000
6	17,000 ≤ VD < 19,000
7	19,000 ≤ VD < 20,000
8	20,000 ≤ VD < 22,000
9	VD ≥ 22,000

Smallest target width

Table 2

δ(STW)	STW, ft
0	STW > 300
1	250 < STW ≤ 300
2	200 < STW ≤ 250
3	150 < STW ≤ 200
5	100 < STW ≤ 150
6	50 < STW ≤ 100
7	STW ≤ 50

Cumulative planned dogleg

Table 3

δ(DOG)	DOG, °
0	DOG < 40
1	40 ≤ DOG < 60
2	60 ≤ DOG < 80
3	80 ≤ DOG < 100
4	100 ≤ DOG < 120
5	120 ≤ DOG < 140
6	140 ≤ DOG < 160
7	160 ≤ DOG < 180
8	180 ≤ DOG < 200
9	200 ≤ DOG < 220
10	DOG ≥ 220

tive functional ensures that each drilling factor receives equal weight in the index, but the DDI does not consider the difficulty of drilling the formations penetrated by the trajectory.

An example calculation appears in the accompanying Box 1.

Difficulty index history

K&M Technology Group introduced the DI to characterize the expected difficulty in drilling an extended-reach well. In an extended-reach well, high angles are built before drilling moves on to a distant target.[2] The DI resembles the MRI specification, but the weights employed are frequently specified in terms of a one- or two-dimensional functional, as shown in Equation 2.

DDI example calculation

Box 1

1. Specify well characteristics encountered or expected; e.g., TD = 21,000 ft, AHD = 11,000 ft, VD = 17,500 ft, TORT = 70°

2. Compute DDI:

$$DDI = \log\left[TD\left(\frac{AHD}{VD}\right)TORT\right] = 6$$

Factor description

Five grouped factors define wellbores: well path; mud, temperature, and pressure; casing and redrill; well type and learning curve; and equipment capacity.

1. ***Well path.*** A vertical depth factor δ(VD) employs a stepwise increasing linear function from 8,000-22,000 ft (Table 1). The weight factor is zero for VD < 8,000 ft and saturates when VD ≥ 22,000 ft.

A two-dimensional weight function is defined in terms of the total vertical depth below mud line, VD-WD, and horizontal reach, HD. The smallest target width at TD perpendicular to the well azimuth, STW (ft), determines the weight factor (Table 2).

Because inclination is usually easier to control than azimuth in a deep well, the target width perpendicular to the well trajectory is applied. Shallow wells and very deep wells usually cannot achieve the horizontal reach of aggressively designed moderate-depth wells due to frictional forces and mechanical load limits.

The horizontal reach at TD is computed as the "unwrapped" total length projected onto the horizontal plane. The weight associated with the cumulative planned dogleg at TD, DOG (°), attempts to account for directional changes beyond a simple build and hold plan (Table 3). Applying the cumulative dogleg is similar to the application of TORT in the difficulty index.

The ideal well survey directional plan dogleg is chosen according to well type:

- *2D wells:* Inclination changes are added from spud to TD.
- *S-turn wells:* The cumulative build is added without section doglegs.
- *3D wells:* The survey calculation program calculates cumulative dogleg from spud to TD.

2. ***Mud, temperature, pressure.*** The maximum mud weight, MXMW (ppg) and oil-based mud weight, MXMW/O (ppg), factor applies a stepwise, increasing scale to mimic the operational complexity associated with high-mud-weight systems (Tables 4, 5). δ(MXMW/O) characterizes the complexity, risk, and cost due to lost returns and the propagation of existing or induced fractures in abnormally pressured wells.[3] If a well is drilled in an underbalanced mode, a weight factor δ(U) = 11 is assigned.

The bottomhole static temperature T(TD) weight factor (°F.) employs a stepwise increasing linear function to account for the additional complexity of managing mud systems and personnel safety (Table 6).

Pore pressure and fracture gradients in the subsurface are uncertain in most drilling operations.[4] Using the fracture

Maximum mud weight

Table 4

δ(MXMW)	MXMW, ppg
0	MXMW < 12
1	12 ≤ MXMW < 13
2	13 ≤ MXMW < 14
3	14 ≤ MXMW < 15
4	15 ≤ MXMW < 16
6	16 ≤ MXMW < 17
8	17 ≤ MXMW < 18
10	MXMW ≥ 18

Max. OBM weight

Table 5

δ(MXMW/O)	MXMW/O, ppg
0	MXMW/O < 14
4	14 ≤ MXMW/O < 15
5	15 ≤ MXMW/O < 16
6	16 ≤ MXMW/O < 17
7	MXMW/O ≥ 17

Bottomhole static temp.

Table 6

δ(T)	T, °F.
0	T < 250
1	250 ≤ T < 300
2	300 ≤ T < 325
3	325 ≤ T < 350
4	350 ≤ T < 375
5	T ≥ 375

gradient factor, FG, and the equivalent circulating density, ECD, the string factor NS/ECD assigns a weight depending on the string count and fracture gradient interval (Equation 3). Fracture gradients in hole sizes less than 8½ in. are difficult to drill and can have high ECD due to pipe rotation, cutting pickup when circulation is initiated, and pressure surges due to pipe movement.[5] In larger hole diameters, the ECD is lower and usually not an issue.[6]

3. **Casing, redrill.** The number of casing strings and liners below the drive casing is denoted NS, and Table 7 shows the corresponding weight function. For each liner tied back or string requiring rollers, simple flotation, or inverted string weights, the difficulty index gains one point. Two points are for high-angle wells for each casing string/liner requiring the use of differential techniques or rotation to slide into the hole. Additional weights are assigned as follows:

- Wells that require a cased-hole whipstock kickoff or a cement plug kickoff receive two points.
- Drill pipe whipstock slot recovery wells receive five points.
- Fishing operations that require casing string sections to be cut and pulled, milled, or pilot milled receive two points.

4. **Well type and learning curve.** Exploration wells usually have a higher degree of risk and complexity than a typical development well, and learning economies in development drilling often reduce the difficulty of drilling a series of wells.

Well type and learning is characterized by assigning points:

- 6 points for a rank wildcat.
- 5 points for a near field wildcat.
- 4 points for the first well in a development program, or in areas with no drilling in the past 2 years.
- 2 points for the second well in development program, or no drilling for at least 1 year.
- 1 point for the third well in development program, or no drilling for the past 6 months.

Number of strings Table 7

δ(NS)	NS
0	1
1	2
2	3
4	4
6	5
9	≥ 6

5. **Equipment capacity.** The drilling rig and system used will affect drilling success; complex systems require additional planning and well time. A jack-up or platform rig with a surface wellhead is assigned the weight "1," tension leg platforms and spar systems with surface BOPs and subsea hangers the weight "3," and floaters with subsea BOPs/wellhead the weight "5."

A number of operational constraints may also arise. Big rigs usually place no constraints on well design or operations but new or stacked rigs may experience extra mechanical problems. If the rig and crew have not previously worked for the operator's drilling group, additional time may be required. Weight factors are assigned as follows:

- 0—extra capacity rig.
- 3—rig at capacity.
- 6—undersized rig.
- 4—new rig or stacked within 90 days.
- 4—time span between rig activation date and spud date less than 30 days.
- 2—time span 31-60 days.
- 1—time span 61-90 days.
- 2—rig and crew have not worked for the operator within the last 2 years.

DI definition

The difficulty index of well w is denoted DI = DI(w) and defined as the summation of the one- and two-dimensional weight functionals, $\delta(f_i)$ and $\hat{\delta}(f_i, f_j)$, as shown in Equation 4. An example calculation appears in the accompanying Box 2.

DI discussion

The difficulty index is intended to gauge the difficulty of drilling an extended-reach well, and as a gross measure it may be useful to compare the various factors that impact drilling.

Unfortunately, there is no basis to the weight assessment beyond subjective reasoning. The weight functions vary with one or more factors and may be more robust than the drilling factors employed in the MRI, but the weights are not calibrated with empirically derived data.

The DI weight functions are user-defined, similar to the DDI and MRI metrics, and this limits the application of the formula since the weights are not supported by empirical analysis.

It is possible in theory to discriminate among wells on the basis of the tactics employed in drilling, since some of these tactics may be observable, but frequently, most of the tactics are not reported or available for analysis.

MSE history

The concept of mechanical specific energy was defined by Simon[7] and Teal[8] to quantify the efficiency of the energy used to destroy a given volume of rock. MSE has been used to evaluate the efficiency of drill bits,[9] postwell performance analysis,[10] and most recently, as a real-time tool to maximize the rate of penetration and obtain a more objective assessment of drilling efficiency.[11-14]

Drilling rates are often constrained by factors that the driller does not control and in ways that cannot be documented. Dupriest[13] classifies factors that determine ROP into two categories: factors that create inefficiency or "founder," and factors that limit energy input. The three causes of founder are bit balling, bottomhole balling, and vibrations.

Bit balling occurs when material accumulation within the cutting structure interferes with the transfer of energy to the rock. Bottomhole balling is a condition in which the build up of material on the bottom of the hole interferes with the transfer of energy from the bit to the rock beneath it.

Both conditions inhibit transfer of a portion of the WOB to the cutting structure, lower the depth of cut, and reduce ROP. When the bit vibrates it loses cutting efficiency. Whirl refers to lateral vibrations, stick slip refers to torsional vibration, and bit bounce describes axial vibrations of the drillsting.

Other factors may also limit energy input, such as hole cleaning efficiency, hole integrity, mud motor differential pressure rating, and logging rotational speed limits.

MSE definition

The MSE is not a cost or complexity estimation model; it's an operational tool to optimize ROP and drill the technical limit. MSE is the calculated work that is being performed to destroy a given volume of rock. Teale derived MSE Equation 5, where Tor is the torque and DIA is the diameter of the drillbit.

Lab tests showed that when a bit is operating at its peak efficiency, the ratio of energy to rock volume will remain relatively constant, regardless of changes in ROP, WOB, or RPM. This relationship is used operationally to adjust drilling parameters to avoid founder and to manage the drilling process.

The instantaneous penetration rate depends upon rock strength, borehole pressure, and formation fluid pressures. Typically, increasing borehole pressure will reduce penetration rate in an impermeable rock, while increasing the borehole and pore pressure differential will reduce penetration rate in a permeable rock. ROP is related to the MSE, the bit diameter, and the power input to drilling by Equation 6.

The highest penetration rate that can be achieved under ideal drilling conditions is described by the technical limit penetration rate shown in Equation 7.

Curry correlated rotating days, normal days, and total dry hole days/1,000 m against TLSE for a small set of wells.[11] The correlation for rotating days was strong, but for the wider measures of drilling performance, many factors besides drillability affect performance.

MSE discussion

Operations personnel study the performance of successful wells to identify success factors and to duplicate the success. The tendency has developed to use the bit, bottomhole assembly, and directional steering system in offset or similar wells.[14]

ROP management as practiced by ExxonMobil focuses on the extension of limitations, rather than the identification of superior bit systems. ROP is advanced by identifying specific limiters and reengineering, rather than seeking a better performing system from empirical experience.

DI EXAMPLE CALCULATION

Box 2

1. Specify well characteristics encountered or expected to be encountered; e.g., a rank wildcat is drilled with a surface BOP with subsea hangers and VD = 12,000 ft, WD = 2,000 ft, HD = 4,500 ft, DOG = 65°, MXMW = 15 ppg, MXMW/O = 16 ppg, T(TD) = 300° F., NS/ECD = 2, NS = 5
2. Compute weight factors: δ_1(VD) = 3, δ_2(VD-WD, HD) = 1, δ_3(DOG) = 5, δ_4(MXMW) =4, δ_5(MXMW/O) = 6, δ_6(T(TD)) = 2, δ_7(NS/ECD) = 2, δ_8(NSD) = 6, δ_9(rank wildcat) = 6, δ_{10}(surface BOP) = 3
3. Compute DI:

   $DI = \Sigma\,\delta_j(f) = 38$

The field process for using MSE allows drillers to adjust parameters and observe whether the MSE increases or declines. Parameters are maintained to minimize MSE. After optimizing drilling, engineering redesign is often necessary to adjust nozzles and flow rates to achieve the highest hydraulic hp/sq in.

Dupriest describes the use of MSE surveillance to optimize the drilling process work flow through the identification of the best operating parameters and by providing the quantitative data to costs to justify design changes.[12-14]

Conclusion

Many factors influence penetration rate and as metrics become further removed from the technical aspects of drillability, additional factors influence the performance measures. Several methods exist to quantify drilling cost and complexity, which attempt to balance the variability involved in the operation with the uncertainty of selecting relevant factors in constructing a descriptive model.

The JAS and MRI are commonly employed in the Gulf of Mexico but relatively little attention has been devoted to the structural basis of the procedures or reliability of the assessment. There have been recent advances, however, in using the MSE to manage and quantify the drilling process. ✦

References

1. Oag, A.W., and Williams, M., "The directional difficulty index—a new approach to performance benchmarking," IADC/SPE 59196, IADC/SPE Drilling Conference, New Orleans, Feb. 23-25, 2000.
2. Shirley, Kathy, "Extended-reach drilling: the viable alternative for field development," The American Oil and Gas Reporter, 46 (4), April 2003, pp. 97-104.
3. Tibbits, G., Tek, T., Long, R.C., Miller, B.E., and Black, A.D., "World's first benchmarking of drilling mud-hammer performance at depth conditions," IADC/SPE Drilling Conf., Dallas, Feb. 26-28, 2002.
4. Proehl, Tom S., "Geomechanical uncertainties and exploratory drilling costs," SPE/ISRM 78230, Rock Mechanics Conf., Irving, Tex., Oct. 20-23, 2002.
5. Hannegan, Don M., "UBD tolls and technology solve conventional deepwater drilling problems," AADE National Drilling Technical Conf., Houston, Mar. 27-29, 2001.
6. "Benchmarking deep drilling final report," Schlumberger Data and Consulting Services, Pittsburgh, November 2004.
7. Simon, R., "Energy balance in rock drilling," SPE Journal, December 1963, pp. 298-306.
8. Teale, R., "The concept of specific energy in rock drilling," Int. J. Rock Mech. & Mining Sci., Vol. 2, 1965, 57-73.

9. Rabia, H., "Specific energy as a criterion for bit selection," JPT, July 1985, pp. 1225-29.

10. Pessier, R.C., and Fear, M.J., "Quantifying common drilling specific coefficient of sliding friction," SPE 24584, SPE Annual Technical Conf. and Exhibition, Washington, DC, Oct. 4-7, 1992.

11. Curry, D., Christensen, H., Fear, M., Govzitch, A., Huges, B., and Aghazada, L., "Technical limit specific energy—an index to facilitate drilling performance evaluation," SPE/IADC 92318, SPE/IADC Drilling Conf., Amsterdam, Feb. 23-25, 2005.

12. Dupriest, Fred E., and Koederitz, William L., "Maximizing drill rates with real time surveillance of mechanical specific energy," SPE 92194, SPE/IADC Drilling Conf., Amsterdam, Feb. 23-25, 2005.

13. Dupriest, F.E., "Maximizing ROP with real-time analysis of digital data and MSE," IPTC 10706, International Petroleum Technology Conf., Doha, Nov. 21-23, 2005.

14. Dupriest, F.E., "Comprehensive drill-rate management process to maximize rate of penetration," SPE 102210, 2006 SPE Annual Technical Conf. and Exhibition, San Antonio, Sept. 24-27, 2006.

Now that fieldbus is used in virtually all new refineries, oil and gas companies are looking beyond the older, established products and their problems to more modern fieldbus hardware solutions that promise to make installations even more reliable, productive, and efficient. This article discusses the advantages and problems with new developments in fieldbus.

Fieldbus developments improve process control system operations

Harry Wilson
MooreHawke
North Hills, Calif.

Ten years ago, the oil and gas industry pioneered fieldbus installations and helped in development and testing of fieldbus hardware and software. Its participation paid off in that fieldbus moved beyond demonstration and "proof of concept" projects to the point where virtually all new operations are based on fieldbus.

During the initial phases of fieldbus, few hardware developments occurred. Vendors were more concerned with ironing out the bugs and making the systems work than they were in pushing fieldbus technology. Users and vendors alike learned to live with the drawbacks and difficulties of fieldbus because the end result of a fieldbus installation had so many benefits.

Typical benefits of projects using fieldbus are faster start-ups, higher sustained operating levels, and fewer unscheduled outages. Additionally, planned outages are rarer and take less time.

Most of these benefits result from effective use of the information available from the intelligent fieldbus devices and systems. Fieldbus technology also provides the ability to put control in the field and to run unattended operations, such as oil platforms. Some fieldbus-based oil platforms connect to a land-based central control system via wireless and run completely unattended for weeks at a time.

Fieldbus also eliminates the need to adjust, tune, and calibrate instruments in the field. Instead, maintenance personnel can perform instrument calibrations and diagnostics from the control room, via human-machine interface screens—even from hundreds of miles away.

The most significant trend in fieldbus is the ongoing development of better physical-layer hardware.

Problems

Fieldbus systems based on 10-year-old technology often cause several operations and maintenance headaches, including:

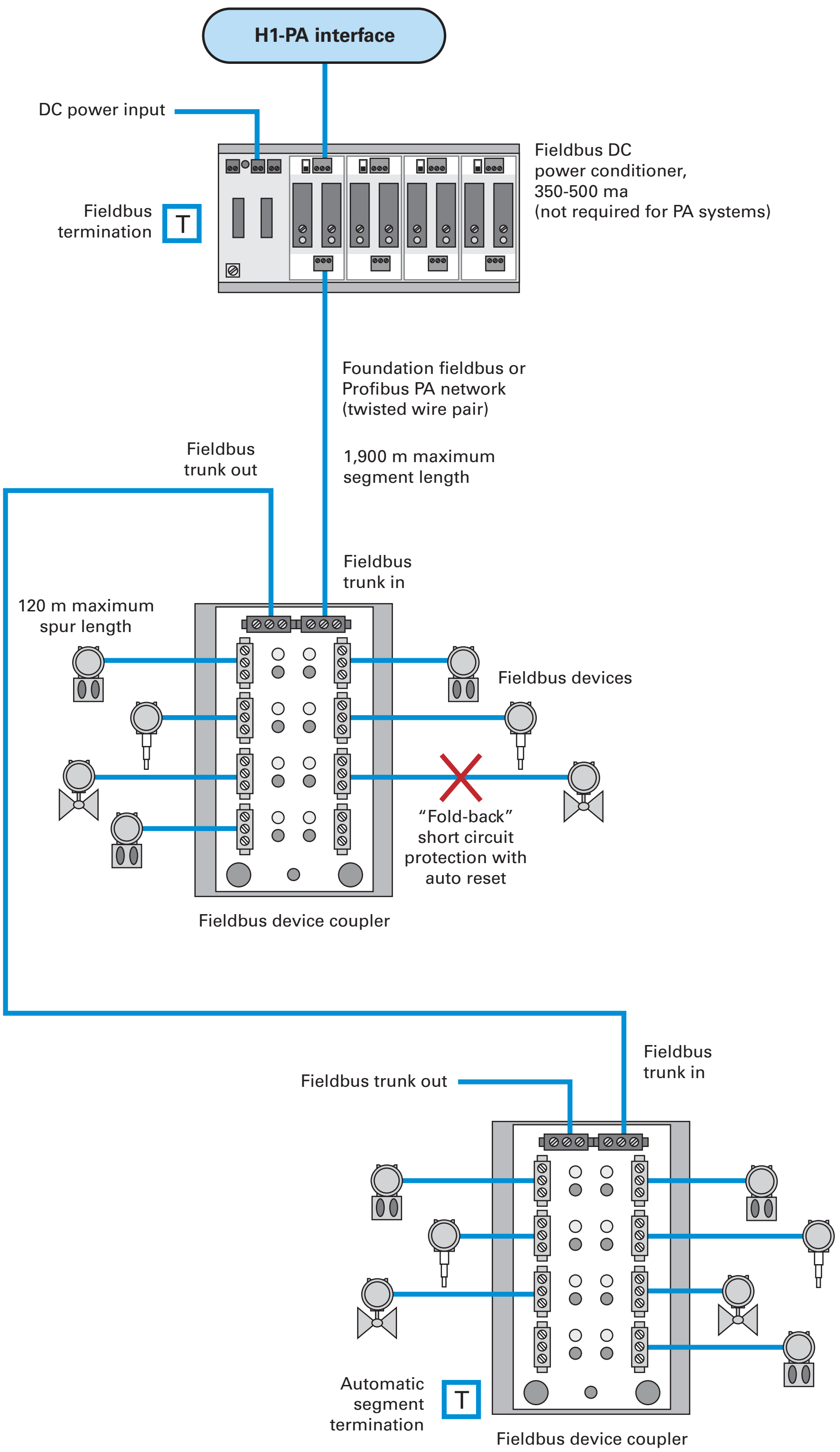
- Installation and start-up.
- Surviving short circuits.
- Removing and replacing instruments.
- Operating in hazardous environments.
- Redundancy in critical loops.

One of the most baffling operational problems over the past 10 years occurred during start-ups, when technicians couldn't get the instruments to work over the fieldbus connection. In many cases, it was a simple installation problem: The segment was over- or underterminated. All fieldbus segments must be properly terminated to prevent communications errors through signal reflections.

Fig. 1 shows the square T boxes of a properly terminated fieldbus segment. Essentially, segment terminators must be present at the beginning and end

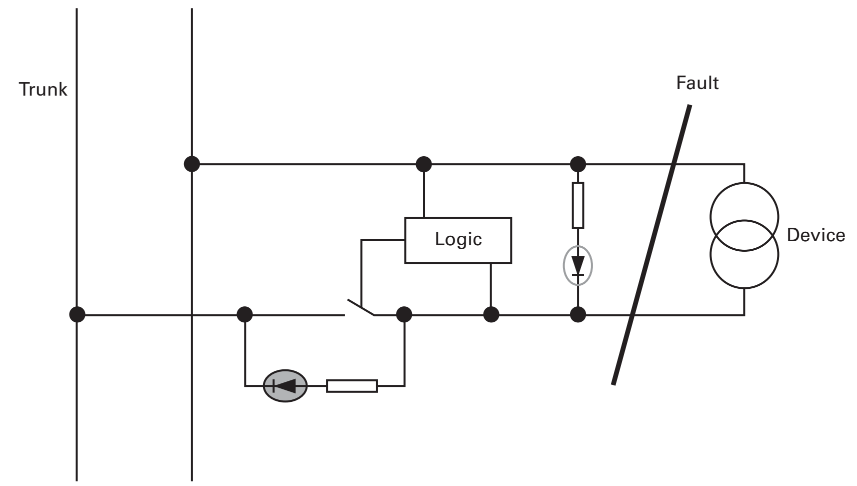
FIELDBUS SEGMENT TERMINATIONS

Fig. 1



Fold-back protection

Fig. 2



of a segment. More or fewer than two terminators cause problems.

Many installation subcontractors paid no attention to the terminators. They either forgot them completely or simply installed them everywhere. Neither approach allowed the segment to operate properly. Often, physical inspection of all junction boxes and field enclosures on each segment was the only way to locate and correct terminator settings.

This still happens today because many plants continue to use older device couplers that require the terminator to be hardwired or manually engaged via an on-off switch.

The problem was eliminated with development of device couplers with automatic segment terminators. The automatic segment terminator greatly assists in segment commissioning by eliminating the issue of over or under-terminating.

If multiple field device couplers are used, the autoterminator is always activated at the farthest unit, and automatically migrates up the segment if a coupler is disconnected.

Physical layer diagnostics

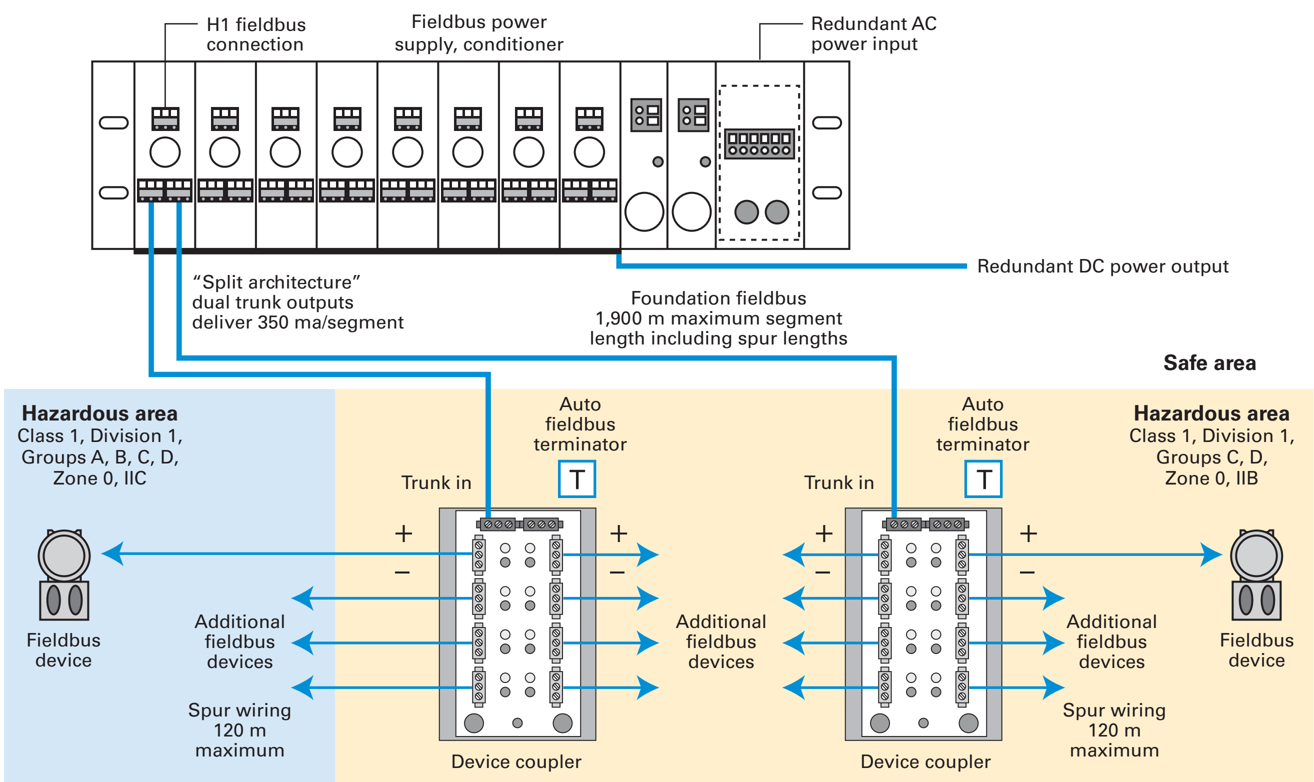
Another trend is the increasing number of physical layer diagnostic tools that can be portable or integrated into the overall system design.

Few engineers realize that practically none of the large control system vendors makes its own fieldbus physical layer equipment, such as segment power supplies and device couplers. Approved third-party fieldbus vendors typically supply this equipment.

Fortunately, all the physical layer

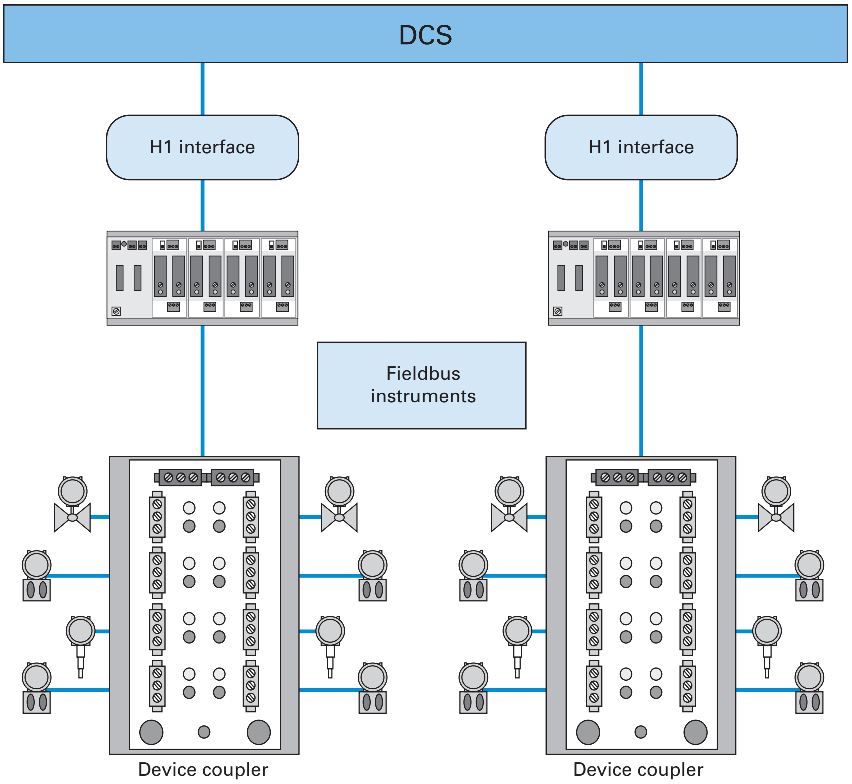
Split architecture

Fig. 3



CONVENTIONAL REDUNDANCY

Fig. 4



fieldbus suppliers are (or will be) making diagnostic hardware and software available. This promises to make life a little easier for plant maintenance departments.

Short circuits

Short circuits are a problem in any fieldbus installation. Maintenance technicians can jostle cables, corrosion can weaken connections, and vibration from pumps and motors can loosen cables and connectors.

Because all devices are in parallel on the segment, a short anywhere can shut down the entire segment if there is no short-circuit protection. The specifying engineer should ensure that short-circuit protection is available for each spur.

Older fieldbus device couplers use a "current limiting" approach to short-circuit protection. This technique limits the amount of current the short-circuit fault can draw to 40-90 ma.

This "current-limited" approach protects the system, but puts an additional burden on the segment until the short is eliminated. The additional current draw causes a voltage drop, which can deprive other instruments on the segment of the minimum 9 v they need to operate. When devices have less than 9 v, they drop off the segment.

A typical fieldbus segment has 350 ma at 25 v available, enough to theoretically power as many as 16 20-ma fieldbus devices. The specifying engineer, however, must also take into account voltage drop due to cable runs.

For example, in a system with 10 devices and 4,000 ft of cable, the end device receives 10.52 v, which is adequate. If a short occurs and is current limited to 60 ma, this takes away enough power so that the remaining devices receive less than 9 v, and some will drop off the segment. If two shorts occur, many more devices could drop off, and an entire process unit might go down.

With older fieldbus equipment, specifying engineers must allow a safety margin. They do this by designing for a fault in their segment. Accordingly, they do not install as many instruments as the segment can theoretically power, limiting instead the number of devices on the segment.

By limiting the number of devices that can be connected to every segment they ensure continuous operation of the segment despite a short in the spur.

The latest device coupler technology uses "fold-back" short circuit protection; the fold-back circuit disconnects a shorted spur from the segment. The fold-back technique has a logic circuit on each spur (Fig. 2) that detects a short in an instrument or spur, and disconnects that spur from the segment.

A trickle current is then used to detect when the short has been removed. The trickle current and current used to run a warning LED use only 4-5 ma during a short. Because this current is less than the typical device current, users actually see an increase in voltage at the device coupler.

Using device couplers with this capability allows the maximum number of devices in a segment, and allows users to make full use of fieldbus capabilities—not to mention the advantage of not having devices fall off the network and cause operational confusion.

Hazardous area maintenance

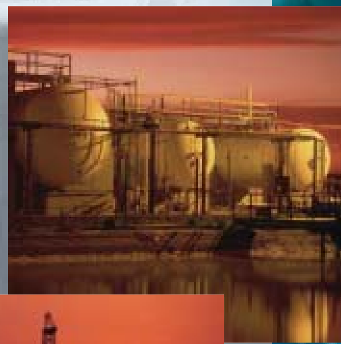
Maintenance people working in hazardous areas want to be able to remove devices from fieldbus segments without turning off the whole segment, and without going through complex disconnection procedures and mechanical interlocks. Specifying fieldbus device couplers properly will avoid these headaches.

Modern designs have nonincendiary, energy-limited spurs that allow disconnection in Division 2, Zone 2 applications. In Zone 1 applications, a device coupler that has a magnetic interlock on each spur should be specified.

The technician puts the key in the

OGJ Surveys in Excel!

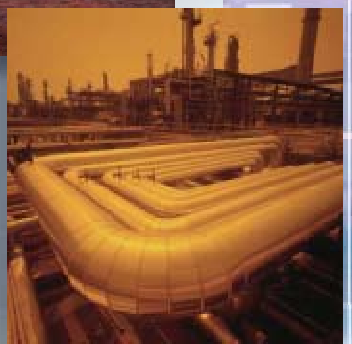
Your Industry Analysis Made Cost Effective and Efficient



Put the *Oil & Gas Journal* staff to work for you! Employ our Surveys with accepted standards for measuring oil and gas industry activity, and do it the easy way through Excel spreadsheets.

Oil & Gas Journal Surveys are available from the OGJ Online Research Center via email, on CD, or can be downloaded directly from the online store. For more information or to order online go to www.ogjresearch.com.

OIL&GAS JOURNAL online research center™



For Information
E-mail: orcinfo@pennwell.com
Phone: 1.918.831.9488 or 1.918.832.9267

To Order
Web site: www.ogjresearch.com
Phone: 1.800.752.9764 or 1.918.831.9421

Numbers You Can Count On Every Time!

Oil & Gas Journal Surveys

Worldwide Refinery Survey — All refineries worldwide with detailed information on capacities and location. Updated annually in December.
E1080 $795.00 Current E1181C $1,495.00 Historical 1986 to current

Worldwide Refinery Survey and Complexity Analysis — Minimum 1 mg of space required. Updated each January.
E1271 $995.00 US

International Refining Catalyst Compilation — Refining catalysts with information on vendor, characteristics, application, catalyst form, active agents, etc.
CATALYST $295.00 US Current

OGJ guide to Export Crudes-Crude Oil Assays — Over 190 of the most important crude oils in world trade.
CRDASSAY $995.00 US Current

Worldwide Oil Field Production Survey — Field name, field type, discovery date, and depth. Updated annually in December.
E1077 $495.00 US Current E1077C $1,495.00US Historical, 1980 to current

Enhanced Oil Recovery Survey — Covers active, planned and terminated projects worldwide. Updated biennially in March.
E1048 $300.00 US Current E1148C $1,000.00 US Historical, 1986 to current

Worldwide Gas Processing Survey — All gas processing plants worldwide with detailed information on capacities and location. Updated annually in July.
E1209 $395.00 US Current E1219C $1,195.00 US Historical, 1985 to current

International Ethylene Survey — Information on country, company, location, capacity, etc. Updated in March.
E1309 $350.00 US Current E1309C $1,050.00 US Historical, 1994 to current

LNG Worldwide — Facilities, Construction Projects, Statistics LNGINFO $395.00 US

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current		Historical 1996–Current	
Refinery	E1340	$395.00 US	E1340C	$1,495.00 US
Pipeline	E1342	$395.00 US	E1342C	$1,495.00 US
Petrochemical	E1341	$395.00 US	E1341C	$1,495.00 US
Gas Processing	E1344	$195.00 US	E1344C	$ 795.00 US

U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040 $545.00 US

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
PIPEMILL $695.00 US

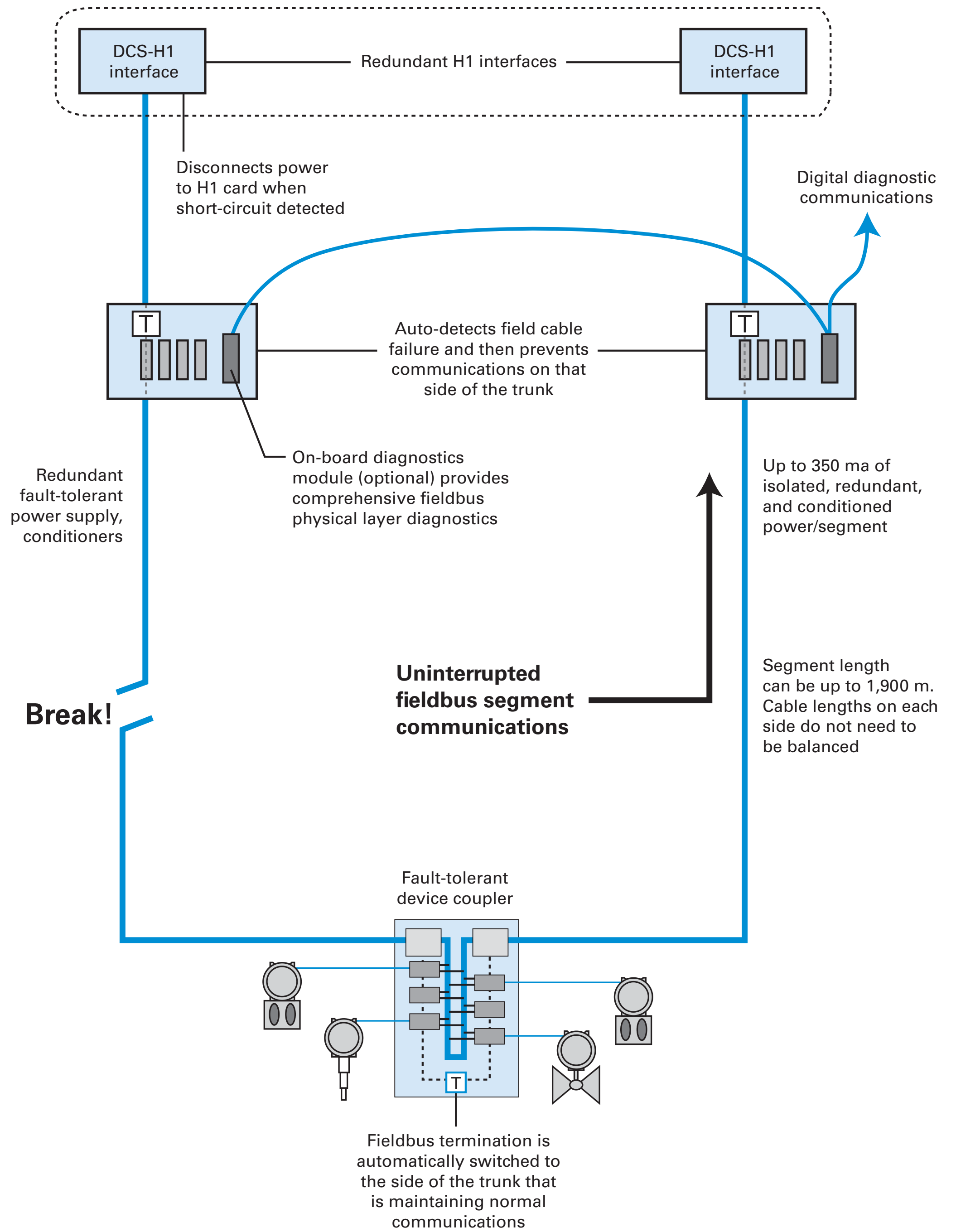
OGJ 200/100 International Company Survey — Lists valuable financial and operating data for the largest 200 publicly traded oil and gas companies.
E1345 $395.00 US Current E1145C $1,695.00 US Historical 1989 to current

OGJ 200 Quarterly — Current to the most recent quarter. OGJ200Q $295.00 US

Production Projects Worldwide — List of planned production mega-projects Location, Project Name, Year, Production Volume, Operator and Type
PRODPROJ $395.00 US

FAULT-TOLERANT SYSTEMS

Fig. 5



slot, which de-energizes the spur, and makes it accessible for rewiring without shutting down the segment. This works if IEC/AEx (NEC 505) standards are being followed, since the device coupler can fit inside an Exe/AExe enclosure and spurs are fully accessible in Zone 1.

Under NEC 500, user options in Division 1 are limited to explosion-proof enclosures with complex live demateable plug-sockets or restrictive power-down procedures, at significantly higher costs.

Intrinsically safe systems

Intrinsic safety (IS) restricts the amount of available energy and remains safe even if the connecting wires are shorted accidentally in a hazardous location. IS systems are popular in Europe, Brazil, Canada, etc.

Fieldbus and IS have a fundamental conflict, however: Fieldbus can theoretically use up to 32 devices on one segment, whereas IS concepts are designed to limit current, voltage, and power to low levels. Standard IS barriers for fieldbus offer about 80 ma/segment.

Major IS vendors introduced the fieldbus intrinsically safe concept (FISCO) as a way around some of these restrictions; but in reality a FISCO system requires expensive barriers and power supplies, and supports only a small increase in current—up to 115 ma in Group ABCD/IIC applications. FISCO also dramatically reduces the mean time between failures of the system and cuts the allowable cable length in half.

In the latest development in IS, a split-architecture concept offers all the benefits of fieldbus without the restrictions of a barrier alone or FISCO.

Essentially, it splits the barrier into two pieces, one piece at the safe-hazardous interface and the other piece in the field in the device coupler (Fig. 3).

This design allows a full 350 ma/segment, access to the full length of 1,900 m/segment and 120 m/spur, and still maintains standard IS approvals at the device connections.

Cost savings are dramatic. When Boehringer Ingelheim Chemicals, Petersburg, Va., converted its plant from traditional IS to a split-architecture system, it found that it was able to install 17 fieldbus devices on a segment vs. only 4 devices on a traditional IS segment.

The savings in enclosure space from eliminating barriers allowed it to install four DeltaV controllers in cabinets that previously held only one with the older IS system.

A recent enhancement in split-architecture systems is the incorporation of FISCO compatibility at the field device coupler. Having FISCO and Entity compatibility at the device coupler enables users to implement intrinsically safe fieldbus with any desired mix of approved devices.

Redundant systems

One of the major user concerns with fieldbus is the exposure of so many devices and loops to a single-point failure in the interface card, power conditioner, or segment cable. Neither Foundation fieldbus (FF) nor Profibus PA addresses the issue, and no standards exist for building a redundant system with fieldbus. FF systems can support redundant H1 cards and redundant power conditioners, but Profibus PA still has no redundancy whatsoever.

Consequently, oil and gas engineers typically limit severely the number of devices on a critical segment (two devices/segment is typical). Another approach is to duplicate the segments—including fieldbus cards, power supplies, device couplers and field instruments (Fig. 4). When the DCS determines that a problem exists on one segment, it can switch to the other.

Special software is then required within the DCS to operate in 1oo2 or 2oo3 modes, with all the associated plant override, maintenance, and fall-back issues.

Newer fieldbus systems allow segment cables to be split into two trunks, each independently powered and connected to a dedicated device coupler in the field. No special software is required and this fault-tolerant configuration maintains communications, in spite of any single point failure, for any DCS.

Even better, the fault-tolerant system has two continuously active trunks, which means that the user can forget that classic nagging doubt: "Will the back-up system be ready and able to pick up if the active system goes down?" Hardware duplication and special software are a thing of the past for the majority of process critical applications.

Fig. 5 shows that newer fault-tolerant systems run duplex communications and automatically disable any faulty trunk, eliminating the need to duplicate field instruments for a significant savings in hardware costs with much higher availability.

No special software is required for the system and DCS software configuration remains the same. This new fault-tolerant system helps prevent the loss of a complete segment, the shutdown of associated plant or equipment, and potential catastrophic process failures.

The cost of the hardware is only slightly more than that of conventional fieldbus devices. This means it should be possible to install redundant fieldbus segments on any control segment. ✦

The author

Harry Wilson (hwilson@miinet.com) is an application consultant for MooreHawke, North Hills, Calif. He has also served as director of marketing for ABB, general manager of systems marketing for Yokogawa, and manager of applications marketing for Foxboro. He holds a MS in electrical engineering, control systems, from the University of Texas. He is a member of ISA.

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

Dynamic simulation useful for reviewing plant control, design

Sissy Psarrou
Yiannis Bessiris
Ivor Phillips
Vassilis Harismiadis
Hyperion Systems Engineering
Nicosia, Cyprus

While plants continually become more complex, chemical engineers, with the advent of computers and commercial off-the-shelf simulation software, can now successfully redesign processes and control systems much faster and better than in the past.

Technology used to optimize material flows and increase plant throughput, maximize equipment efficiency, review resource use, and enhance planning and logistics, is now mature. Furthermore, access to experimental data, integrated solutions and "what-if" scenarios is easier and more valuable than ever before.

This article explores some of the process modeling techniques used with emphasis on dynamic simulation.

Chemical engineers can perform difficult calculations in a short time and use tools fit for purpose, i.e., steady-state tools for basic design and dynamic modeling for reviewing controllability and distributed control system (DCS) checkout. For a project-driven organization, however, and in which reliability and accuracy of results are paramount, the following questions constantly arise:

- Are the thermodynamics and the reactor kinetics correct?
- Are the data correct? Do we understand the control scheme?
- Are there any smart methods to perform the allocated tasks in less time?

Understanding unit operations, questioning the model-obtained results, and asking questions to the more experienced engineers are the strongest requirements for success in using dynamic simulations for process control and design.

Process modeling

Using first principle, rigorous models allows engineers to simulate any process in great detail and analyze scenarios and situations that, in the real plant, would be difficult to monitor or are dangerous. For plants that are being designed, one must:

- Demonstrate overall controllability, safe operability, reliability, and the adequacy of process for all start-up, operating, transient, and shutdown conditions.
- Meet regulatory demands for emissions and depressurizing.
- Test and accept the plant's DCS and emergency shutdown schemes.
- Develop operating procedures and train the operators to maximize production and quickly react to abnormal situations.

Conversely, for existing plants, engineers are typically required to:

- Maximize production and debottleneck specific plant areas.
- Verify that a planned DCS update will be smooth with minimal process disruptions and ensure that new automations and sequences will operate as intended.
- Improve control strategies and implement advanced control.
- Financially optimize the costs to the added-value balance.

In this article, we first review the process modeling requirements for some of these obstacles. This article also examines the differences between standard steady-state process simulation and dynamic modeling.

Finally, the article also reviews special requirements of modeling for dynamic studies or a detailed checkout of the DCS logic and control loops.

Steady-state, dynamic modeling

Steady-state modeling means that the modeled process is solved only for a specific set of operating conditions. This is like a snapshot of the unit operation. Any change in the plant conditions requires solving the model again. After converging, the model should predict where the process will settle.

On the other hand, dynamic modeling provides information about the unit operation over time. All variables are solved at each time step and at any specific time that the process conditions are monitored. Compared to the steady-state "snapshot" equivalent, dynamic

---

Based on a presentation to the 6th Pan-Hellenic Conference in Chemical Engineering, Athens, May 31-June 2, 1007.

modeling is more of a movie than a single picture.

Using one or the other technique really depends on the operator's requirements. For process design, a steady-state model of the unit is typically sufficient. When unit controllability is in question or the process response to transients must be investigated, however, a dynamic model is needed.

The main difference in dynamic and steady-state modeling has to do with the level of detail required. Steady-state modeling uses process specifications and focuses on process feasibility.

For example, if the temperature at the tube side of a heat exchanger is equal to a certain temperature, a minimum temperature approach is assumed. In dynamic simulation, the heat transfer coefficient of the exchanger should be estimated first from existing data (equipment datasheet, heat and material balance, or equivalent). Then the flows are estimated based on pressure drops and resistances across the heat exchanger. Only then, the temperature at the exchanger exit can be calculated.

Furthermore, one should understand the tricks used. For example, in steady-state modeling, pumps are rarely modeled; flow is possible from low to high pressure; distillation column reboilers and condensers are typically integrated within the first and last column equilibrium stage. In dynamic modeling, resistances across valves and piping are important; pressure and flow boundaries are typically used; and exact pump and compressor curves should be used.

Engineering studies

When increased confidence in the unit design is required, a detailed engineering study is recommended. This is typically the case for expensive equipment exhibiting controllability difficulties during major process upsets, like start-ups or shutdowns (normal and emergency). Model results are evaluated, issues uncovered, engineering solutions proposed, and finally, the unit design is modified.

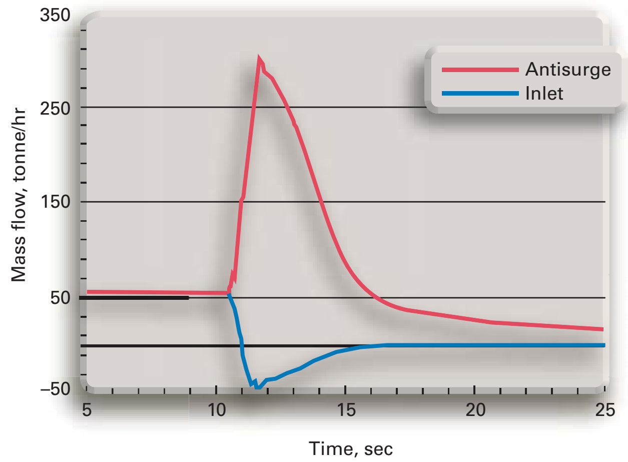
The nature of engineering studies is such that modeling should be as detailed and exact as possible. In addition to the process and instrumentation diagrams and process flow diagrams, detailed datasheets are required for all equipment in scope.

Moreover, isometric diagrams are needed so that the actual pipe volume and resistances can be evaluated and taken into account. Lastly, the entire process-control philosophy must be incorporated so that the model-unit responds to disturbances in exactly the same way as the real unit.

The modeling engineer should be experienced and should have a clear understanding of the unit operation and critical parameters before starting the modeling. The engineer therefore focuses on the important modeling aspects and will be able to interpret the observed process behavior during testing. Typically, a thorough understanding of electric motors, steam and gas turbines, and relative inertia calculations is required.

TYPICAL STUDY RESULTS

Fig. 1



DCS check, training simulators

A major undertaking for a new plant is development of the control system. It is the online, real-time software integrated with the necessary hardware that will ensure that the plant can be properly operated.[1 2]

Engineers test the DCS operation by actually triggering one by one all inputs and verifying that the output is behaving correctly.

Fig. 1 shows typical study results for a motor-driven compressor that is tripped. Before delivering this result to the client, the modeling engineer must verify that the results obtained by the model have physical meaning. The engineer must ask "is the reverse flow observed real or a model artifact?" or "are the calculated flows reasonable?"

This is a lengthy and costly endeavor. There is no easy way to follow though the DCS code, however, especially when complex sequences, alarms, and shutdown sequences are involved.

The preferred solution is therefore integration with a dynamic process model. System snapshots can therefore be saved easily and recalled when required, while process and DCS modifications can be readily made and evaluated.

Major differences between the dynamic models suitable for DCS testing and those suitable for training simulators have to do with the available graphics. This is due to the fact that engineers are performing the DCS testing, and operators will be using a training simulator. In the typical case, engineers do not have a great need for fancy graphics with buttons and emulated hand-switches or bypass signals. Many variables will be triggered directly from the model.

Trends in process modeling

The past few years have seen the rise of integrated modeling environments that provide the ability to model and optimize the plant (engineering suites, point solutions) or the whole enterprise (supply chain, demand planning, etc.). These products have matured; they are not "engineering tools" any more, but commercial off-the-shelf products, ready to be used.

Currently:

- The main driving force behind major product development is model reuse and its ability to be used for the plant's entire life.
- Interactions of the major engineering suites with the "environment" become standardized.
- Upward product compatibility is maintained.
- Connectivity with external or client-delivered models and applications is achievable using a variety of tools (Dll, OPC, MS Excel, VBA, Fortran, C++, C#) is provided.
- Windows-based systems take up the space previously reserved exclusively by UNIX.
- Rival products exploit standard connectivity. Using the proper API calls or the proper model export and import facilities (text, xml) and some programming or scripting, one may use models under a competing product suite.
- Modeling is becoming a commodity. Only web-based technologies supported by major groups seem to be those that will survive in the longer term. ✦

References

1. "Distributed control system," Wikipedia, http://en.wikipedia.org/wiki/Distributed_control_system.

2. "OPC dictionary and glossary of terms," MatrikonOPC, http://www.matrikonopc.com/resources/dictionary.asp?range=a

The authors

Sissy Psarrou (s.psarrou@hyperionsystems.gr) is a senior engineer for Hyperion Systems Engineering, Athens. She has 8 years' experience in the detailed modeling of refining, chemical, and polymer systems for engineering studies and operator training simulators. Psarrou holds a PhD in Chemical Engineering from the National Technical University of Athens. She is a member of the Technical Chamber of Greece.

Yiannis Bessiris (y.bessiris@hyperion.com.cy) is a business development manager for Hyperion Systems Engineering, Nicosia, Cyprus. He has also served as a process engineer for Procter & Gamble, Brussels. Bessiris has 7 years' experience in the development of large scale and full scope high-fidelity process simulations for the oil, gas, and power industries. He holds a MSc in chemical engineering from the University of Patras, Greece.

Ivor Phillips (i.phillips@hyperion.com.cy) is a technology manager for Hyperion Systems Engineering, Nicosia, Cyprus. With 15 years' experience in the process simulation industry, he has also served as senior consultant and lead engineer at Fantoft UK Ltd. and ABB Simcon Inc. He holds a BSc in chemical engineering from Loughborough University, UK.

Vassilis Harismiadis (v.harismiadis@hyperionsystems.gr) is a business development manager for Hyperion Systems Engineering, Athens. He has 9 years' experience in the oil and gas industry with particular emphasis on the use of latest technology to improve plant effectiveness. His special expertise is in the area of operator training using virtual plant technology. Harismiadis holds a PhD from the National Technical University of Athens in the thermodynamic modeling of complex systems; most of the work was performed at the Shell Research Technical Center, Amsterdam. He is a member of the Technical Chamber of Greece.

Waxy crude shutdown method yields savings

Fan Hua-jun
Zhang Jin-jun
China University of Petroleum
Beijing

Huang Jin-ping
PetroChina Pipeline Co.
Shenyang, China

A new method for determining the maximum shutdown time of a waxy crude oil pipeline is not only more accurate and flexible, but can also yield substantial savings in heating costs compared to the subjective methods employed before a pipeline enters service.

Pipeline operators often heat waxy crude lines to ensure safe and economic transport.[1] Shutdowns may occur regularly for operational reasons and occasionally for such emergencies as pipe ruptures.[2] Shutdowns lower the temperature of the oil, increasing its viscosity and strengthening its thixotropic tendencies,[3] the combination of which requires a large start-up pressure. Start-up pressure exceeding the capacity of the pipe could lead to pipe failure, resulting in potentially large economic losses.[4]

Increasing heating temperature before a planned shutdown can help ensure a successful restart. An accidental shutdown, however, requires that restart occur before a predetermined maximum shutdown time has elapsed. This time can be increased by heating the line after the shutdown has occurred. The operator must, however, return the pipeline to service before reaching the MST, even if it means incurring such associated risks as soil contamination.

For large-throughput hot oil pipelines, however, reducing the heating temperature even slightly may save a great amount of fuel,[4] creating a potential conflict with the desire to maximize MST. How to save fuel while ensuring reliable and safe operations therefore becomes an important question.

Background

China has subjectively established different MSTs for different seasons for different hot waxy crude pipelines,[5 6] with little attention given to the MST's rationality. Subjective determination is necessary and practical for a new pipeline. Continued use of the same MST for many years, however, exposes the pipeline to both potential inefficiencies and potential safety concerns.

New developments in emergency tools and technology have also greatly reduced the time required to deal with an accident, further increasing the need to reevaluate MST for hot waxy crude pipelines.

This article accounts for the uncertain duration of an accidental shutdown and proposes an accident response reliability index to assess how individual accidents are handled. Simple methods use this index to determine and evaluate the MST of hot waxy oil pipelines in operation for a few years. A case study then illustrates these methods and the results are analyzed. Results show that the proposed methods can both save fuel and ensure effective response to accidents during pipeline operation.

Accident index

The longer the time available to deal with an accident, the more likely it is to be addressed successfully, with the reverse also holding true. The relationship between the required time and the available time to deal with accidents can therefore characterize the success with which pipeline accidents are addressed, yielding an accident response reliability index.

Equation 1 defines and calculates the index, R, which in turn represents the probability of successfully addressing a pipeline accident. A large R means a high probability that the accident will be effectively addressed.

Determining MST

Many factors influence the time required to deal with an accident: its location, type, etc.[7] Most of these factors are uncertain and stochastic. It is very complex, perhaps even impossible, quantitatively to investigate the relationship between the time required to deal with an accident and its factors. But pipelines with many years of operation-

Actual accidental shutdown lengths, hr; July 2006-July 2007

Table 1

Shutdown	hr	Shutdown	hr	Shutdown	hr	Shutdown	hr
1	10.75	13	10.17	25	3.53	37	9.83
2	9.25	14	13.50	26	8.00	38	11.58
3	9.72	15	12.00	27	7.30	39	11.45
4	9.47	16	3.50	28	8.97	40	9.67
5	5.83	17	7.83	29	12.12	41	14.00
6	11.75	18	9.00	30	4.67	42	11.32
7	7.50	19	5.08	31	3.82	43	17.80
8	6.50	20	1.67	32	6.05	44	8.83
9	10.50	21	5.08	33	13.15	45	11.83
10	13.00	22	2.58	34	10.57	—	—
11	10.50	23	4.00	35	16.63	—	—
12	14.83	24	11.20	36	13.43	—	—

Equations

$$R = P(t_p > t) \qquad (1)$$

Where:

$P(t_p > t)$ = the probability of t_p exceeds t.

t_p and t = the available time and the required time to deal with an accident.

$$R_{max} = P(t_{max} > t_r) \qquad (2)$$

t_{max} and t_r = the MST and actual shutdown time to deal with encountered accidents for the pipeline.

$$W = \left\{\sum_{k-l}^{[n/2]} a_k(W)[x_{(n+l-k} - X_{(k)}]\right\}^2 \Big/ \sum_{k=l}^{n}(X_{(k)} - \overline{X})^2 \qquad (3)$$

Where:

n/2 means mixmal integer not bigger than n/2.

$X_{(k)}$ and $\overline{X}$ = the k - th sample and the average value of n samples.

$$\sum_{k=1}^{45}(X_{(k)} - \overline{X})^2 = 622.44 \left\{\sum_{k=l}^{[[n/2]]} a_k(W)[X_{(n+l-k} - X_{(k)}]\right\}^2 = 607.05 \qquad (4)$$

Where:

$W = 607.05/622.44 \approx 0.975$

$$R_{obj} = \frac{l}{\sigma_{tl}\sqrt{2\pi}}\int_0^{t_p} \exp\left[\frac{-(tl - \mu_{tl})^2}{2\sigma_{tl}^2}\right]dtl \qquad (5)$$

Where:

tl, μ_{tl} and σ_{tl} = actual accidental shutdown time, its mean and standard deviation.

t_p = the shutdown time to realize the objective safety requirement.

R_{obj} = an ARRI corresponding to the safety requirement of the pipeline.

al history will instead have actual accidental shutdown data recorded.

The actual shutdown times can represent the time required time to deal with accidents, while the MST, as the longest possible shutdown time, can represent the available time. Substituting the MST and actual accidental shutdown times into Equation 1 yields Equation 2; calculating the accident response reliability index for a given MST.

Equation 2 can also use the real shutdown times and distribution law to determine MST for a given pipeline.

The following steps, therefore, determine a pipeline's MST:

- Gather the data. Collect shutdown times, accident type, cause, position, etc.
- Determine the distribution of actual shutdown times. Analyze the data and remove invalid points. Integrate the valid data and use hypotheses testing to study the distribution of the actual shutdown times.
- Obtain objective reliability from the pipeline operator.
- Determine MST. Simulate the distribution of the actual shutdown times and iteration calculation according to the operator's objective reliability.

MST evaluation

The length of MST affects both the transportation cost and the efficiency with which accidents can be addressed.

The following steps evaluate the rationality of a given MST:

- Gathering actual accidental shutdown data and the safety requirements of the pipeline. This requires gathering as much accidental shutdown data as possible and determining their distribution.
- Calculating the accident response reliability index of the pipeline using MST. Integrate the gathered data and determine the distribution of the accidental shutdown time using hypotheses testing. Then use Equation 2 to calculate ARRI.
- Comparing the calculated ARRI and an objective one. If the former is much smaller than the later, the MST is unreasonable in terms of safety. If the calculated ARRI is much larger than the objective value, however, the MST is similarly unreasonable due to unnecessary heating.

An ARRI a bit smaller than the safety requirement yields a reasonable MST. A calculated ARRI a bit larger than the safety requirement, however, requires further calculation before making judgment.

Case study

A pipeline in northeast China, 720-mm OD and 459 km long, provides an example, using one input station, one terminal, and five intermediate heating-pumping stations. The pipeline has operated for 34 years and has a safety target of 0.999.

Given that accident shutdown times from many years ago would no longer represent actual shutdown times, Table 1 only considers accidental shutdowns that occurred over the past 6 years. The longest shutdown measures 17.8 hr, and the shortest 1.67 hr.

The W test method often judges if probability distribution of studied samples meets the norm. The W method requires between 3 and 50 samples. The 45 samples studied here satisfy this requirement.

The following sequence can determine the distribution law:[8]

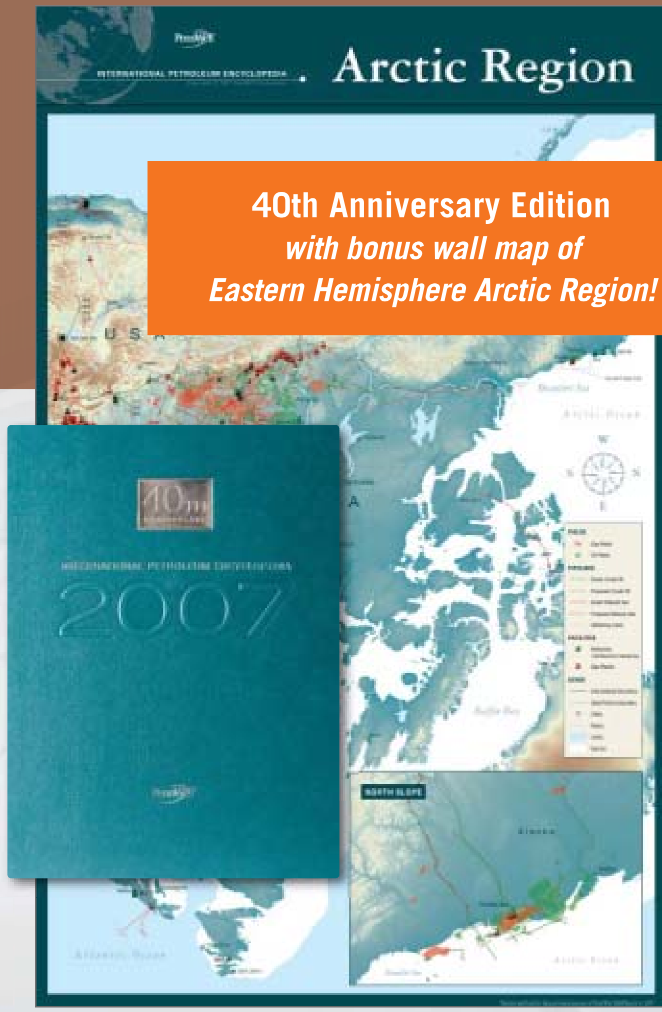
- Sort the samples in ascending sequence: $X_{(1)}$ $X_{(2)}$......$X_{(n)}$.
- Calculate W (Equation 3). Table 2 calculates and lists the value of $X_{(n+l-k)}$-$X_{(k)}$ and $a_k(W)$.
- If $W < W_\alpha$, reject the null hypothesis H_0; the actual shutdown time doesn't meet the normal distribution. Otherwise, accept the null hypothesis H_0.

Equation 4 shows the values calculated by Table 2.

Values of α=0.05 and n=45, yield W_α=0.945. For $W > W_\alpha$, accept the

the INTERNATIONAL PETROLEUM ENCYCLOPEDIA

trusted by energy industry executives for 40 years



40th Anniversary Edition
with bonus wall map of Eastern Hemisphere Arctic Region!

The annual *International Petroleum Encyclopedia (IPE) 2007* has been the premier resource for the petroleum and energy industries worldwide for four decades. The 40th Anniversary Edition features new articles, new statistics, and new and up-to-date maps.

- **Bonus wall map of the Eastern Hemisphere Arctic Region,** showing activity, infrastructure, and exploration potential in Alaska, Northern Canada, and Greenland.
- **Atlas country reports on 118 nations,** including new entries for Cambodia, Uganda, and Nicaragua, and more.
- **Key statistics for the year's most important energy trends, including:**
  - Future energy supply.
  - Reserves and production.
  - Drilling and exploration.
  - LNG industry outlook, liquefaction and receiving, carrier fleet, risks and opportunities.
  - Investment and markets.
  - Trade and tankers.
  - Refining and products.
  - Gas processing & products.
  - Petrochemicals outlook.
- **Statistics from the *Oil & Gas Journal* and *BP Statistical Review of World Energy 2006*,** as well as the US Energy Information Administration, including data for:
  - Oil and natural gas production, consumption, imports/exports, and prices.
  - Oil refineries, capacities, margins, and throughput.
- **Chronology of events.**
- **Guest essay** authored by a senior executive from the Chevron Corporation.
- **Directory of national oil companies and energy ministries.**

Print	*Read-only CD-ROM*	*Set (Book/CD-ROM)*
484 Pages/Hardcover/June 2007	ISBN13 978-1-59370-123-9	Order No. I2007SET
ISBN13 978-1-59370-103-1	**Price: $195.00 US**	**Price: $331.50 US**
Price: $195.00 US		

ORDER YOUR COPY TODAY!

www.pennwellbooks.com
800.752.9764

PennWell®

Place a standing order & save 20%!

To order please complete this form and fax or mail it to Pennwell with your check, money order, or credit card information.
1421 S. Sheridan, Tulsa, OK 74112 USA • Tel.: 800.752.9764 or 918.831.9421 • Fax: 918.831.9555

___ (Quantity) Book(s) at $195.00 each (US$)__________
___ (Quantity) CD(s) at $195.00 each (US$)__________
___ (Quantity) Set(s) at $331.50 each (US$)__________

US SHIPPING (FEDEX GROUND) (US$)__________
1 item $4.00
2 items $5.00
3 items $6.00

TAX (US$)__________
AZ, CA, CO, FL, GA, IL, MI, NJ, NY, OK, PA, RI, TX & WA residents

☐ **Check here to place a standing order & save 20%!**

TOTAL ORDER (US$)__________

PAYMENT OPTIONS:

☐ Cash ☐ Check ☐ Bill Company (Acct. No.)__________
☐ Credit Card (circle one)
AMEX Visa Mastercard Discover Diners Club

Signature__________
Account No.__________ Exp.__________
Name on Card__________

SHIP TO:

Name:__________
Company:__________
Address:__________
City/State/Zip:__________
Tel:__________ Fax:__________
Email:__________

☐ *Billing Address Same as Shipping Address*

BILL TO:

Name:__________
Company:__________
Address:__________
City/State/Zip:__________
Tel:__________ Fax:__________
Email:__________

VALUES OF $X_{(n+1-k)}$-$X_{(k)}$ AND $a_k(W)$ Table 2

$X_{(k)}$	$X_{(46-k)}$	$X_{(46-k)}$-$X_{(k)}$	$a_k(W)$	$X_{(k)}$	$X_{(46-k)}$	$X_{(46-k)}$-$X_{(k)}$	$a_k(W)$
1.67	17.80	16.13	0.3850	6.50	11.75	5.25	0.0959
2.58	16.63	14.05	0.2651	7.30	11.58	4.28	0.0860
3.50	14.83	11.33	0.2313	7.50	11.45	3.95	0.0765
3.53	14.00	10.47	0.2065	7.83	11.32	3.49	0.0673
3.82	13.50	9.68	0.1865	8.00	11.20	3.20	0.0584
4.00	13.43	9.43	0.1695	8.83	10.75	1.92	0.0497
4.67	13.15	8.48	0.1545	8.97	10.57	1.60	0.0412
5.08	13.00	7.92	0.1410	9.00	10.50	1.50	0.0328
5.08	12.12	7.04	0.1286	9.25	10.50	1.25	0.0245
5.83	12.00	6.17	0.1170	9.47	10.17	0.7	0.0163
6.05	11.83	5.78	0.1062	9.67	9.83	0.16	0.0081

MST, SAFETY REQUIREMENT LEVELS Table 3

Safety requirement	0.99	0.999	0.9999
MST, hr	18	21	23

MST, ACCIDENT RESPONSE RELIABILITY INDEX Table 4

MST, hr	20	30
ARRI	0.998	1.000

HEATING CONSUMPTION, GJ/DAY; 21, 30-HR MST Table 5

	Shutdown group A — June and October			Shutdown group B — (July, August, and September)		
Pipeline pump station*	30-hr MST	21-hr MST	Savings, GJ/day	30-hr MST	21-hr MST	Savings, GJ/day
1	782.4	714.4	68.0	446.6	400.2	46.4
2	624.0	581.9	42.1	499.2	447.2	52.0
3	699.8	646.1	53.7	362.9	347.9	15.1
4	713.8	659.3	54.5	365.0	335.2	29.8
5	691.6	622.6	69.0	354.0	327.3	26.7
6	657.6	603.0	54.6	385.6	355.2	30.3
Total	**4,169.2**	**3,827.3**	**341.8**	**2,413.3**	**2,213.0**	**200.3**

*Throughput, 19,200 b/d.

null hypothesis H_0; the actual accidental shutdown time meets the normal distribution.

Equation 5 can calculate the ARRI for the studied pipeline with a given shutdown time.

Iterative calculation yielded a 21-hr shutdown time based on the safety requirement of 0.999 and the accidental shutdown time records.

The safety requirements of a pipeline operator also affect the length of MST determined by the proposed method. Different MSTs for the pipeline studied in this article satisfied different safety requirement levels of the operator (Table 3). A safety requirement of 0.9999 needed a 23-hr MST, while only 18 hr were needed to meet a safety requirement of 0.99.

MST rationality

Shutdowns of 20 hr MST occurred on the pipeline in January, February, March, April, May, November, and December; 30-hr MST shutdowns in June, July, August, September, and October.[6]

Table 4 lists the ARRI for the MSTs.

An ARRI of 0.998 existed for the 20-hr MST, a deviation of only 0.001 from the objective value of 0.999. The 20-hr MST therefore satisfied basic safety requirements and was reasonable in terms of fuel economy. The fact that no accidents had failed to be properly resolved due to a lack of time in the past 33 years further proved that a 20-hr MST was sufficient.

An ARRI of 1.000 existed for the 30-hr MST. Although it had the same deviation of 0.001, a 21-hr MST was proven by further calculations to be enough to realize the safety requirement of 0.999, making a 30-hr MST unnecessary.

Table 5 lists the studied pipeline's heating consumptions for both a 21 and 30-hr MST. The 5 30-hr MST months represented two groups, divided according to environmental conditions. Group A includes June and October. Group B includes July, August, and September. The pressure at restart determined safe pumping temperature, replacing the more conventional pour-point temperature method of reaching this determination.[9, 10]

Reducing MST to 21 hr from 30 hr can save 341.8 GJ/day of heating consumption in June and October at a throughput of 19,200 tons/day (Table 5). Heat supplied by oil with a heating value of 44.1×10^6 J/kg would therefore save 7.75 tons/day of oil in June and October, for a total saving during the 2 months of 472 tons. A similar reduction of MST for July, August, and September would save 200.3 GJ/day; or 4.54 tons/day of oil, for a total savings of about 417 tons of oil.

Reducing MST to 21 hr from 30 hr would save a total of 889 tons of oil over the 5 months studied, demonstrating that the 30-hr MST in place was uneconomical.

Acknowledgments

The authors thank Wei Li, who gathered part of the actual shutdown time data used in this work. ✦

References

1. Xiaoheng Yang and Guozhong Zhang, Design and management for oil transportation pipelines, Beijing: Petroleum University Press, 1996.

2. Chang, C., Nguyen, Q.D., and Ronningsen, H.P., "Isothermal start-up of pipeline transporting waxy crude oil," Journal of Non-Newtonian Fluid Mechanics, No. 87, pp. 127-154, 1999.

3. Dafan Yan and Zheming Luo, "Rheological properties of Daqing crude oil and their application in pipeline transportation," SPE Production Engineering, No. 11, pp. 267-276, 1987.

4. Jinjun Zhang, Jianlin Ding, et al., "Determination of safe pumping

temperature for waxy crude pipelines," International Pipeline Conference, Calgary, Sept. 25-29, 2006.

5. Q/SHGD 0048-2001, Safe operation code for waxy crude oil pipelines, 2001.

6. Dispatcher manual for northeast pipelines.

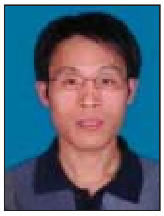
7. Guozhong Zhang and Zhixiang Ma, "Determination of safe and economic transportation temperature in hot oil pipelines," Journal Acta Petrolei Sinica, Vol. 25, No. 1, pp. 106-109, 2004.

8. Xiang Li, Yongle Li, and Qingjun Hu, Applied Mathematical Statistics, Beijing: National University of Defense Technology Press, 2001.

9. National Development and Reform Commission, The operation and regulation of crude oil pipelines, November 2004.

10. Kang Xu, "Study on the flow safety evaluation of buried waxy crude pipelines and its application," PhD dissertation, China University of Petroleum (Beijing), 2005.

The authors



Huajun Fan (fhaujun@126.com) is a PhD candidate at the China University of Petroleum at Beijing. He holds a BS (1998) in mechanical design and manufacturing engineering and has 4 years' working experience in the petroleum industry and 5 years' experience in the research of crude oil pipeline transportation.

JinJun Zhang (zhangjj@cup.edu.cn) is a professor and head of the department of petroleum storage and transportation at China University of Petroleum at Beijing. He holds BS (1982), MS (1987), and PhD (1998) degrees in petroleum storage and transportation engineering from the CUPB and has 25 years' experience in teaching and research of crude oil theory and pipeline transportation.

Jinping Huang (hjp82402@sohu.com) is supervisor of dispatchers at PetroChina Pipeline's Shenyang dispatch center. She holds a BS (1987) in petroleum storage and transportation and has worked at PetroChina Pipeline Co. as a senior engineer since 1991. Huang has worked in pipeline operation technologies and management for 20 years.

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

Equipment/Software/Literature

New motor mount encoder helps reduce downtime

The new Dynapar HSD35 motor-mount encoder is designed to reduce large motor downtime via a shaft seal, unbreakable code disk, and optional redundant outputs.

The new encoder uses optical technology combined with field serviceable connectors.

Mounting options include stamped metal or swivel ball tethers for TEFC or C-face mounting.

The encoder replaces the firm's NorthStar MagCoder. The HSD35 incorporates a field-serviceable EPIC connector requiring no special tools or soldering irons for connection—a simple slotted screwdriver is all that's needed, the firm notes. Conduit or cable can be wired directly to the encoder via ½-in. NPT connection.

Overall rating of the unit is IP65/NEMA 4, and the shaft seals are proved to the more stringent IP67, the company points out. A sister product, the HS35 encoder, is rated to the full IP67 rating. Use of the included back-end shaft cover and mating gasket helps make the unit even more resistant to contamination.

The HSD35 uses an unbreakable disk made of a highly engineered plastic, currently offered on the 2048 PPR resolution model. Lower resolution models use an unbreakable metal disk.

Source: **Danaher Industrial Controls**, 1675 Delany Rd., Gurnee, IL 60031.

New wireless integrated pressure switch, receiver

The Meriam/ADALET wireless integrated pressure switch and receiver has been added to this firm's line of electrical enclosure, instrumentation, and accessory products.

The wireless system is suited for pressure measurement applications such as tank levels, power generation, process control, flow monitoring, and pipelines. The system utilizes license-free frequency hopping spread spectrum technology, as well as AES encryption, to protect data integrity with a secure and accurate signal.

The integrated pressure switch's transmitter, contained in a transparent polycarbonate antenna dome, provides unhindered data transmission as far as 3,000 ft. With as much as 500 mW of transmission power available, the switch is powerful enough for applications that require constant monitoring, the company says.

Source: **AD Products Co.**, 4799 W. 150th St., Cleveland, OH 44135.

Services/Suppliers

Knowledge Systems Inc.

Houston, has elected Jamey Webster as chief executive officer. Webster, who served as the company's chief operating officer for the past four years, succeeds the founder, Jim Bridges, who will continue as chairman of the board.

Before joining Knowledge Systems, Webster held leadership positions for US Senator Phil Gramm, US Congressman Kevin Brady, and Texas Lt. Governor David Dewhurst.

Knowledge Systems Inc. is a leading provider of software and services for the worldwide oil and gas drilling industry.

Rockwell Automation Inc.

Milwaukee, has announced its acquisition of Industrial Control Services Group Ltd., which does business as ICS Triplex. Headquartered in Maldon, UK, ICS Triplex is a leading global supplier of critical control and safety solutions to the process industries.

Rockwell Automation will operate the new acquisition under its current brand name, as a part of Rockwell's Control Products & Solutions operating segment.

Rockwell Automation Inc. provides industrial automation control and information solutions for customers across a wide range of industries around the globe. The company looks to the acquisition of ICS Triplex to gain a strong foothold in the oil and gas, chemical, and power generation industries.

Red Man Pipe & Supply Co. and McJunkin Corp.

Tulsa, Okla., and Charleston, W.Va., respectively, have announced a merger of equals which will make the new company one of the leading industrial and oil field PVF suppliers in North America. Craig Ketchum, president and CEO of Red Man Pipe & Supply Co., and H.B. Wehrle III, CEO and president of McJunkin Corp., will serve as co-chief executive officers for the new company.

Red Man Pipe & Supply Co. was founded in 1977 as a distributor of oil field and industrial supplies to the oil and gas, petrochemical, refining, pipeline, transmission, utility, and chemical industries.

Founded in 1921, McJunkin Corp. distributes industrial pipe, valve fittings, and other products to a wide variety of industries including oil and gas exploration, refining, chemical, and petrochemical.

Noble Denton Group

London, has announced its acquisition of Poseidon Maritime UK Ltd., headquartered in Aberdeen.

Poseidon Maritime provides marine and marine safety consultancy services, primarily to the offshore oil and gas exploration and production industry.

Noble Denton Group, a global offshore and marine consulting firm, has employees in all key oil and gas industry centers in Europe, North and South America, the Middle East, and Asia.

Statistics

Imports of crude and products

	Districts 1-4 7-27 2007	Districts 1-4 7-20 2007	District 5 7-27 2007	District 5 7-20 2007	Total US 7-27 2007	Total US 7-20 2007	Total US *7-28 2006
	1,000 b/d						
Total motor gasoline	1,167	1,503	58	149	1,225	1,652	1,327
Mo. gas. blending comp.	824	1,009	51	110	875	1,119	785
Distillate	339	206	0	51	339	257	473
Residual	322	315	0	0	322	315	562
Jet fuel-kerosine	145	128	120	61	265	189	224
Propane-propylene	66	83	0	0	66	83	279
Other	289	225	0	73	288	298	931
Total products	**3,152**	**3,469**	**228**	**444**	**3,380**	**3,913**	**4,581**
Total crude	**9,060**	**9,328**	**1,105**	**1,050**	**10,165**	**10,378**	**10,431**
Total imports	**12,212**	**12,797**	**1,333**	**1,494**	**13,545**	**14,291**	**15,012**

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

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

OGJ crack spread

	*8-3-07	*8-4-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	85.61	93.73	–8.11	–8.7
Brent crude	76.27	76.29	–0.02	—
Crack spread	9.34	17.43	–8.09	–46.4
FUTURES MARKET PRICES				
One month				
Product value	86.77	92.17	–5.40	–5.9
Light sweet crude	76.78	75.07	1.71	2.3
Crack spread	9.99	17.11	–7.12	–41.6
Six month				
Product value	86.08	86.63	–0.56	–0.6
Light sweet crude	74.44	77.85	–3.41	–4.4
Crack spread	11.64	8.78	2.85	32.5

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

Purvin & Gertz LNG netbacks—Aug. 3, 2007

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.43	4.67	5.62	4.57	5.27	5.60
Everett	4.91	2.85	4.53	2.94	3.42	5.21
Isle of Grain	4.97	2.91	4.54	2.81	3.47	4.42
Lake Charles	3.58	1.72	3.33	1.87	2.12	4.19
Sodegaura	4.92	6.89	5.12	6.76	6.09	4.38
Zeebrugge	5.77	3.83	5.25	3.73	4.39	5.26

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	13,688	55,204	26,335	10,844	48,107	14,693	4,191
PADD 2	67,917	48,264	15,665	6,623	28,176	1,163	21,362
PADD 3	192,072	63,653	27,046	13,705	36,081	15,407	22.536
PADD 4	13,782	5,990	1,847	507	2,907	350	[1]1,965
PADD 5	57,072	31,609	22,345	9,440	11,271	5,577	—
July 27, 2007	**344,531**	**204,770**	**93,238**	**41,119**	**126,542**	**37,190**	**50,054**
June 20, 2007	**351,028**	**204,134**	**92,521**	**40,665**	**123,653**	**37,503**	**47,940**
July 28, 2006[2]	**333,723**	**210,868**	**92,583**	**40,054**	**132,558**	**42,861**	**58,199**

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

Refinery report—July 27, 2007

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Refinery output Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,606	1,623	1,932	102	502	109	64
PADD 2	3,210	3,206	2,104	211	887	44	212
PADD 3	8,054	8,010	3,503	678	2,134	328	704
PADD 4	608	604	319	26	199	16	[1]151
PADD 5	2,853	2,767	1,571	424	605	180	—
July 27, 2007	**16,331**	**16,210**	**9,429**	**1,441**	**4,327**	**677**	**1,131**
June 20, 2007	**15,989**	**15,822**	**9,271**	**1,446**	**4,133**	**732**	**1,064**
July 28, 2006[2]	**15,796**	**15,516**	**9,037**	**1,480**	**3,834**	**628**	**1,086**
	17,443 operable capacity		**93.6% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 8-1-07	Pump price* 8-1-07	Pump price 8-2-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	254.3	294.0	304.3
Baltimore	245.7	287.6	308.6
Boston	244.4	286.3	303.3
Buffalo	243.5	303.6	311.9
Miami	254.3	304.6	314.9
Newark	243.7	276.6	299.9
New York	242.5	302.6	309.6
Norfolk	239.0	276.6	303.9
Philadelphia	247.0	297.7	317.3
Pittsburgh	237.3	288.0	301.5
Wash., DC	257.6	296.0	322.3
PAD I avg.	246.3	292.1	308.9
Chicago	254.6	305.5	334.0
Cleveland	218.7	265.1	297.1
Des Moines	248.7	289.1	290.6
Detroit	247.4	296.6	297.7
Indianapolis	249.1	294.1	291.0
Kansas City	245.2	281.2	294.8
Louisville	260.1	297.0	299.4
Memphis	251.2	291.0	295.4
Milwaukee	244.8	296.1	298.7
Minn.-St. Paul	238.6	279.0	292.4
Oklahoma City	237.3	272.7	286.0
Omaha	243.2	289.6	296.2
St. Louis	262.0	298.0	291.1
Tulsa	239.3	274.7	285.0
Wichita	246.7	290.1	289.1
PAD II avg.	245.8	288.0	295.9
Albuquerque	249.8	286.2	297.2
Birmingham	240.0	278.7	290.0
Dallas-Fort Worth	240.0	278.4	300.3
Houston	239.5	277.9	301.1
Little Rock	236.8	277.0	292.8
New Orleans	240.3	278.7	295.6
San Antonio	237.9	276.3	288.6
PAD III avg.	240.6	279.0	295.1
Cheyenne	254.6	287.0	286.8
Denver	267.4	307.8	304.3
Salt Lake City	262.2	305.1	307.0
PAD IV avg.	261.4	300.0	299.4
Los Angeles	253.4	311.9	324.9
Phoenix	264.5	301.9	313.7
Portland	266.6	309.9	303.5
San Diego	264.5	323.0	328.7
San Francisco	261.5	320.0	332.5
Seattle	248.5	300.9	320.1
PAD V avg.	259.6	311.3	320.6
Week's avg.	**248.2**	**291.8**	**302.9**
July avg.	**251.6**	**295.2**	**295.2**
June avg.	**265.9**	**309.4**	**288.4**
2007 to date	**227.9**	**271.5**	—
2006 to date	**220.1**	**263.4**	—

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

REFINED PRODUCT PRICES

	7-27-07 ¢/gal		7-27-07 ¢/gal
Spot market product prices			
		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	206.70
New York Harbor	205.88	Gulf Coast	204.65
Gulf Coast	201.75	Gas oil	
Los Angeles	207.50	ARA	208.17
Amsterdam-Rotterdam-Antwerp (ARA)	192.06	Singapore	201.90
Singapore	195.88	Residual fuel oil	
Motor gasoline		New York Harbor	137.81
(Reformulated-regular)		Gulf Coast	142.26
New York Harbor	211.00	Los Angeles	154.53
Gulf Coast	208.50	ARA	131.92
Los Angeles	222.50	Singapore	145.47

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

BAKER HUGHES RIG COUNT

	8-3-07	8-4-06
Alabama	6	5
Alaska	7	8
Arkansas	50	26
California	36	34
Land	35	29
Offshore	1	5
Colorado	104	93
Florida	1	0
Illinois	0	0
Indiana	4	0
Kansas	15	13
Kentucky	9	6
Louisiana	181	186
N. Land	60	57
S. Inland waters	22	14
S. Land	37	34
Offshore	62	81
Maryland	1	0
Michigan	3	4
Mississippi	14	13
Montana	20	22
Nebraska	0	0
New Mexico	85	88
New York	5	7
North Dakota	40	32
Ohio	13	6
Oklahoma	187	194
Pennsylvania	17	17
South Dakota	4	1
Texas	835	767
Offshore	9	12
Inland waters	1	3
Dist. 1	25	18
Dist. 2	31	25
Dist. 3	65	62
Dist. 4	82	75
Dist. 5	177	141
Dist. 6	113	110
Dist. 7B	38	47
Dist. 7C	58	40
Dist. 8	112	100
Dist. 8A	20	28
Dist. 9	42	31
Dist. 10	62	75
Utah	36	45
West Virginia	32	28
Wyoming	66	107
Others—NV-2; TN-5; VA-2; WA-1	10	3
Total US	**1,781**	**1,705**
Total Canada	**394**	**486**
Grand total	**2,175**	**2,191**
Oil rigs	306	305
Gas rigs	1,470	1,396
Total offshore	74	99
Total cum. avg. YTD	**1,751**	**1,596**

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

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	8-3-07 Rig count	8-3-07 Percent footage*	8-4-06 Rig count	8-4-06 Percent footage*
0-2,500	66	7.5	39	2.5
2,501-5,000	109	53.2	87	41.3
5,001-7,500	226	23.8	233	18.0
7,501-10,000	417	3.5	392	4.5
10,001-12,500	446	1.3	407	0.9
12,501-15,000	274	—	285	—
15,001-17,500	114	—	112	—
17,501-20,000	63	—	72	—
20,001-over	35	—	28	—
Total	**1,750**	**7.8**	**1,665**	**6.1**
INLAND	38		40	
LAND	1,646		1,549	
OFFSHORE	66		66	

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

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]8-3-07	[2]8-4-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	765	666
California	672	677
Colorado	51	64
Florida	7	7
Illinois	32	27
Kansas	97	97
Louisiana	1,375	1,382
Michigan	15	14
Mississippi	50	49
Montana	94	99
New Mexico	166	159
North Dakota	107	111
Oklahoma	169	173
Texas	1,355	1,359
Utah	44	49
Wyoming	145	138
All others	61	71
Total	**5,225**	**5,160**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	8-3-07
Alaska-North Slope 27°	57.84
South Louisiana Sweet	80.25
California-Midway-Sunset 13°	66.30
Lost Hills 30°	74.15
Southwest Wyoming Sweet	69.48
East Texas Sweet	71.50
West Texas Sour 34°	65.15
West Texas Intermediate	72.00
Oklahoma Sweet	72.00
Texas Upper Gulf Coast	68.75
Michigan Sour	65.00
Kansas Common	71.00
North Dakota Sweet	68.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	7-27-07
United Kingdom-Brent 38°	77.22
Russia-Urals 32°	74.83
Saudi Light 34°	72.59
Dubai Fateh 32°	70.56
Algeria Saharan 44°	78.62
Nigeria-Bonny Light 37°	79.06
Indonesia-Minas 34°	78.39
Venezuela-Tia Juana Light 31°	72.33
Mexico-Isthmus 33°	70.87
OPEC basket	74.63
Total OPEC[2]	73.74
Total non-OPEC[2]	73.64
Total world[2]	73.69
US imports[3]	71.36

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

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

US NATURAL GAS STORAGE[1]

	7-27-07	7-20-07	Change
	bcf		
Producing region	928	912	16
Consuming region east	1,511	1,455	56
Consuming region west	401	396	5
Total US	**2,840**	**2,763**	**77**
	May 07	**May 06**	**Change, %**
Total US[2]	**2,179**	**2,310**	**–5.7**

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

Statistics

Worldwide crude oil and gas production

	May 2007	Apr. 2007	5 month average production 2007	5 month average production 2006	Change vs. previous year Volume	Change vs. previous year %	May 2007	Apr. 2007	Cum. 2007
	Crude, 1,000 b/d						Gas, bcf		
Argentina	633	627	631	631	—	—	134.8	128.4	622.44
Bolivia	45	45	45	45	—	–0.9	42.0	41.0	205.00
Brazil	1,725	1,739	1,745	1,712	33	1.9	24.0	24.0	131.00
Canada	2,576	2,625	2,612	2,463	149	6.0	493.9	499.1	2,549.70
Colombia	520	526	520	531	–11	–2.0	18.0	17.5	87.50
Ecuador	511	502	502	547	–45	–8.1	0.3	0.3	1.51
Mexico	3,110	3,182	3,153	3,346	–193	–5.8	184.0	179.0	886.52
Peru	119	109	113	112	1	1.1	6.8	6.0	30.49
Trinidad	125	125	124	152	–28	–18.2	118.0	114.0	570.31
United States	5,179	5,218	5,184	5,056	128	2.5	1,679.0	1,620.0	8,109.00
Venezuela[1]	2,370	2,370	2,410	2,624	–214	–8.2	72.0	70.0	367.00
Other Latin America	80	80	80	79	1	1.6	10.5	7.2	39.63
Western Hemisphere	**16,993**	**17,148**	**17,119**	**17,297**	**–178**	**–1.0**	**2,783.3**	**2,706.5**	**13,600.11**
Austria	17	17	17	17	—	–0.6	5.0	4.9	26.00
Denmark	303	316	313	337	–25	–7.3	19.3	18.9	116.88
France	20	19	19	22	–3	–12.7	3.1	1.7	14.36
Germany	67	68	69	72	–3	–3.6	49.5	49.9	264.50
Italy	106	107	108	113	–5	–4.4	29.0	28.5	146.30
Netherlands	40	40	42	29	13	43.4	150.0	150.0	1,445.00
Norway	2,181	2,427	2,377	2,566	–189	–7.4	240.6	291.4	1,345.34
Turkey	41	41	40	41	—	–1.2	—	—	6.50
United Kingdom	1,577	1,584	1,588	1,628	–39	–2.4	241.1	237.1	1,225.90
Other Western Europe	3	4	4	4	—	–6.7	2.2	2.0	12.55
Western Europe	**4,357**	**4,624**	**4,578**	**4,829**	**–251**	**–5.2**	**739.8**	**784.5**	**4,603.34**
Azerbaijan	870	800	824	580	244	42.1	30.0	21.0	123.00
Croatia	16	16	16	17	–1	–5.3	6.1	5.9	30.27
Hungary	16	17	17	18	–1	–6.2	6.5	7.5	36.79
Kazakhstan	1,250	1,350	1,250	1,018	232	22.8	80.0	80.0	400.00
Romania	100	98	98	100	–2	–1.6	18.0	17.4	88.40
Russia	9,610	9,590	9,666	9,400	266	2.8	1,900.0	1,900.0	9,800.00
Other FSU	450	450	420	520	–100	–19.2	450.0	450.0	2,260.00
Other Eastern Europe	41	49	47	47	1	1.6	87.7	87.4	443.22
Eastern Europe and FSU	**12,354**	**12,370**	**12,339**	**11,699**	**639**	**5.5**	**2,578.3**	**2,569.1**	**13,181.67**
Algeria[1]	1,360	1,340	1,338	1,356	–18	–1.3	290.0	275.0	1,390.00
Angola[1]	1,689	1,679	1,645	1,397	247	17.7	2.6	2.5	12.40
Cameroon	84	83	84	89	–5	–6.1	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	630	630	648	694	–46	–6.6	42.0	40.6	204.60
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.30
Gabon	230	230	230	240	–10	–4.2	0.3	0.3	1.51
Libya[1]	1,710	1,690	1,696	1,680	16	1.0	22.0	21.0	106.50
Nigeria[1]	2,010	2,250	2,188	2,198	–10	–0.5	70.0	75.0	368.00
Sudan	480	480	462	396	66	16.7	—	—	—
Tunisia	108	104	98	64	33	52.2	6.1	6.7	33.37
Other Africa	262	262	262	273	–11	–3.9	10.2	10.0	49.97
Africa	**9,143**	**9,327**	**9,230**	**8,967**	**263**	**2.9**	**443.2**	**431.1**	**2,166.65**
Bahrain	175	171	171	174	–3	–1.6	25.0	23.3	121.53
Iran[1]	3,900	3,970	3,916	3,786	130	3.4	250.0	250.0	1,255.00
Iraq[1]	2,000	2,100	1,956	1,814	142	7.8	5.0	5.0	25.00
Kuwait[1,2]	2,345	2,395	2,409	2,513	–104	–4.1	30.0	30.0	150.00
Oman	710	710	718	756	–38	–5.0	57.0	55.0	280.00
Qatar[1]	800	800	798	818	–20	–2.4	110.0	110.0	545.00
Saudi Arabia[1,2]	8,565	8,465	8,491	9,263	–772	–8.3	160.0	150.0	765.00
Syria	380	390	390	438	–48	–11.0	16.0	15.5	77.90
United Arab Emirates[1]	2,590	2,560	2,570	2,622	–52	–2.0	135.0	130.0	655.00
Yemen	360	360	358	342	16	4.7	—	—	—
Other Middle East	—	—	—	—	—	–26.1	7.8	7.1	39.17
Middle East	**21,825**	**21,921**	**21,778**	**22,526**	**–749**	**–3.3**	**795.8**	**775.9**	**3,913.60**
Australia	437	474	447	357	90	25.2	115.7	112.9	551.46
Brunei	181	180	185	205	–20	–9.8	28.0	35.0	172.60
China	3,791	3,759	3,763	3,695	68	1.8	202.9	188.9	1,003.12
India	668	684	687	669	18	2.7	81.0	80.0	399.87
Indonesia[1]	850	840	848	922	–74	–8.0	190.0	175.0	898.00
Japan	15	18	18	17	1	7.6	12.0	12.2	57.92
Malaysia	690	720	734	740	–6	–0.8	130.0	130.0	663.00
New Zealand	25	20	19	15	4	23.4	15.0	14.0	63.10
Pakistan	69	67	66	65	1	1.8	120.6	114.9	583.43
Papua New Guinea	50	50	52	58	–6	–10.3	0.5	0.5	2.45
Thailand	212	217	211	219	–8	–3.7	80.0	74.6	373.12
Viet Nam	320	320	324	348	–24	–6.9	15.0	14.5	73.00
Other Asia–Pacific	38	36	36	32	4	11.6	96.9	91.6	464.96
Asia Pacific	**7,346**	**7,385**	**7,390**	**7,342**	**48**	**0.6**	**1,087.6**	**1,044.0**	**5,306.02**
TOTAL WORLD	**72,017**	**72,775**	**72,432**	**72,661**	**–229**	**–0.3**	**8,428.0**	**8,311.1**	**42,771.40**
*OPEC	30,189	30,459	30,265	29,596	669	2.3	1,334.0	1,291.0	6,524.50
North Sea	4,080	4,352	4,297	4,548	–251	–5.5	545.6	592.2	3,119.97

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

Your marketplace for the oil and gas industry

DEADLINE for CLASSIFIED ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to CLASSIFIED SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-831-9776,
email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $350 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED CLASSIFIED: $3.50 per word per issue. 10% discount for three or more CONSECUTIVE issues. $70.00 minimum charge per insertion. Charge for blind box service is $50.50 No agency commission, no 2% cash discount. Centered heading, $8.75 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $75.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN CLASSIFIED SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR CLASSIFIED AD.*

EMPLOYMENT

GEOMARKET TECHNICAL ENGINEER

Well Intervention Services

Schlumberger Technology Corporation is seeking to hire a GeoMarket Technical Engineer - Well Intervention Services for its facility in Oklahoma City, Oklahoma to apply concepts of fluid mechanics, reaction chemistry, heat and mass transfer and industry safety standards and requirements to review technical competency of treatment designs and recommend improvements to company products and services; use principles of thermodynamics and reactive chemistry to prevent adverse effects of reactive materials on intervention equipment and select treatments for carbonate, dolomitic and sandstone formations; predict flow rates and friction pressure losses to select appropriate treating conditions and chemicals based on analysis of fluid flow through pipes and fluid rheology; train engineers on implementation of intervention stimulation processes in horizontal and vertical carbonate sandstone completions; analyze formation damage, completion design, log analyses and interpretations, sand and water control procedures and production forecasts to develop client solutions using latest technology; evaluate results of well testing, rate and pressure transient analysis, nodal analysis and magnetic resonance log analysis to recommend strategic placement of key units; provide technical support to sales group for applications involving fluid dynamics, thermodynamics and heat and mass transfer issues. Position requires a Bachelor's degree in Chemical Engineering, Petroleum Engineering or Mechanical Engineering and 5 years of experience performing oilfield well intervention services. Salary commensurate with background. Please send resume to: Schlumberger, Attn: Staffing Manager (Job Code #GMTE-201), 201 N.W. 63rd Street, Suite 200, Oklahoma City, Oklahoma 73116 or by e-mail to: resumes-slb-okc@oklahoma-city.oilfield.slb.com and include Job Code #GMTE-201. See our website at www.slb.com. Schlumberger is an Equal Opportunity Employer.

Baker & O'Brien, Inc. is a well established midsize consulting firm with offices in Dallas and Houston. We are looking to expand our natural gas practice and seeking candidates with technical and commercial experience in the natural gas industry. Consultant position requires working knowledge of natural gas and NGL markets, gathering and pipeline transportation, gas processing/treating, and end use consumption. Experience in the design/engineering, construction, operations, and/or commercial management of midstream facilities is required. Related experience in crude oil and refined products, LNG, power generation, and/or petrochemicals is preferred but not required. Typical client engagements include market and feasibility studies, technology assessment, due diligence, asset valuation, litigation support, and contract disputes/audits. Requirements: US Citizenship, Engineering degree required (Mechanical or Chemical), MBA preferred, Minimum 15 years experience within natural gas industry, Previous consulting experience preferred but not required. Submit resume to resumes@bakerobrien.com.

Established production company located in Denver, Colorado, seeks Petroleum Engineer. Experienced in Rocky Mountain Operations. Retirees welcome. Resumes to Ken McKinney at K.McKinney@grynberg.com

EMPLOYMENT

DST/TCP TECHNOLOGY SUPPORT MANAGER

Schlumberger Technology Corporation is seeking a DST/TCP Technology Support Manager for its facility in Rosharon, Texas to coordinate research and development, product sustaining and new product development for Drill Stem Testing and Tubing Conveyed Perforating (DST/TCP) systems including hydraulic and electro hydraulic control systems for Drill Stem Testing and Tubing Conveyed Perforating systems in high temperature/pressure environments; apply concepts of fluid dynamics, well control, well testing, hydraulics, mechanical engineering, petroleum engineering, shaped charge technology, perforating optimization and wireless telemetry principles to coordinate design, manufacture and delivery of DST/TCP systems for optimized production testing and well completion; apply oilfield industry standards and utilizing enterprise knowledge management principles to develop, manage and disseminate global Drill Stem Test and Tubing Conveyed Perforating Quality Management Auditing, QHSE, Service Delivery Systems, Technical Documentation, and Operational Standards; coordinate DST/TCP product support improvements of documentation, training, communication and product delivery utilizing knowledge management principles for deployment of more robust new technology through improved technical support and comprehensive solutions; provide global DST/TCP technical support for tender and operations project system design and failure analysis; develop and manage equipment selection and procurement guidelines for DST and TCP product lines. Position requires a Bachelor's degree or equivalent (equivalent can be based on education or experience or a combination thereof, determined by using the formula of 3 years of progressive experience equals 1 year of university-level education) in Petroleum Engineering or Petroleum Services and 5 years of experience in knowledge management for the development, deployment and post development support of Drill Stem Testing and Tubing Conveyed Perforation technologies and services. Salary commensurate with background. Please send resume to: Charles van Petegem, DST/TCP Marketing and Technology Manager, Job Code #DST072007, 14910 Airline Road, Bldg. 1, Rosharon, Texas 77583 or by e-mail to: vanpetegem1@rosharon.oilfield.slb.com and include Job Code #DST072007 (no attachments accepted). See our website at www.slb.com. Schlumberger is an Equal Opportunity Employer.

Petroleum Engineer - The Tertiary Oil Recovery Project (TORP) at the University of Kansas has an opening for the position of Petroleum Engineer. Major responsibilities: serving as primary liaison between TORP and Kansas oil and gas operators, developing and managing field demonstration projects, conducting data analysis related to field application of petroleum recovery processes, delivering presentations at TORP technology transfer workshops and seminars. Required: BS degree in Petroleum Engineering or related field with an academic background or work experience related to petroleum reservoir/production engineering. For more information and to apply on-line go to https://jobs.ku.edu and search for position number 00008169. Review of applications begins Oct. 15, 2007. EO/AA Employer.

Reservoir Simulation Engineer in Denver, CO. Participate in multi-disciplinary reservoir modeling/simulation projects using state-of-the-art tools, methodologies and technologies for integrated reservoir studies. Assist project managers in utilizing embedded mathematical techniques in simulation software to analyze reservoir fluid and rock properties using well test, well log surveys, core analysis, fluid measurements and production records in reservoir simulation models. Master's degree in Petroleum Engineering. Nitec LLC.
Resumes via email only to
bsavage@niteclc.com

EMPLOYMENT

Reservoir Simulation Engineer in Denver, CO. Manage multi-disciplinary reservoir modeling/simulation projects using state-of-the-art tools, methodologies and technologies for integrated reservoir studies. Utilize embedded mathematical techniques in simulation software to analyze reservoir fluid and rock properties using well test, well log surveys, core analysis, fluid measurements and production records in reservoir simulation models. Master's degree in Petroleum Engineering. Nitec LLC.
Resumes via email only to:
bsavage@niteclc.com

PROJECT MGR. –
Libya

Outstanding oppor. with international energy firm headquartered in Houston. Two year contract in Tripoli, Libya with option to renew for third year, with oppor. to move up in firm and return to Houston. Project Mgr. shore based, with two mgrs. offshore to supervise operations on FSSO, reporting and maintenance to the Proj. Mgr. Engring Degree + 15 + yrs. exper. with major o&g co., and/or e&c co.,
with mgt. of international cultural groups. Must have exper. with offshore platforms and fixed producing facilities. Live in Tripoli with wife and self. 30 day annual vacation, airfare, $200,000.00 salary + bonus, medical, etc. U.S., Canadian, U.K. or European prefd. Employer Fee Paid.

DEPUTY GENERAL –
Libya

Exec. level position resp. for assisting the General. Mgr. of major oil co. operating in Libya, for directing leadership & in planning & executing the exploration for energy co. in Libya. Serve as Proj. Mgr. for special projects. Maintain communication w/govt. agencies. B.S. in Technical Field (Geosciences &/or Engineering) Libyan Passport Holder. Min. 15+ yrs. with mgt. positions with major or national oil companies. Exceptional compensation. Employer Fee Paid. Reply in complete confidence to:

The Roddy Group, 281.545.2423,
roddygrp@wt.net

REAL ESTATE

Carroll Real Estate Co
Wanted ... ranch / recreational listings
Texas, Oklahoma, New Mexico
903-868-3154

Classified Advertising

EQUIPMENT FOR SALE

REFRIGERATION AND J.T. PLANTS

7.5 MMSCFD, 1000 PSI, NATCO
4.0 MMSCFD, 1000 PSI, NATCO
6.5 MMSCFD, 1250 PSI X 400 PSI, H&H J.T.
2.0 MMSCFD, 1000 PSI, PROCESS EQPT.
OTHERS AVAILABLE
PLEASE CALL 318-425-2533, 318-458-1874
regardres@aol.com

Process Units
Crude Topping Units
~~6,000 BPSD~~ SOLD
10,000 BPSD
14,000 BPSD
Condensate Stabilizer
6,500 BPSD
Catalytic Reformer
3,000 BPSD
Naphtha Hydrotreater
8,000 BPSD
HF Alkylation Unit
2,500 BPSD
Butane Isomerization
3,700 BPSD
Sulfur Recovery Plant II
22T/D
Tail Gas Plant
Amine Treating
300 GPM
FCCU UOP
17,000 available
BASIC EQUIPMENT
Please call: 713-674-7171
Tommy Balke
tbalkebasic1@aol.com
www.basic-equipment.com

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS:10 - 600 MMCFD
AMINE PLANTS:10 – 2,700 GPM
SULFUR PLANTS:10 - 180 TPD
COMPRESSION:100 - 20,000 HP
FRACTIONATION:1000 – 25,000 BPD
HELIUM RECOVERY:75 & 80 MMCFD
We offer engineered surplus equipment solutions.

Bexar Energy Holdings, Inc.
Phone 210 342-7106
www.bexarenergy.com
Email: matt.frondorf@bexarenergy.com

CHROMATOGRAPH

ABB BTU8000 model. Measures C_1-C_6, CO_2, N_2 in the field. Reasonably priced.
Contact Jeff at 918.534.2322 or
jeff@bratco-operating.com

Solar Taurus 60

5.2 MW • Mobile Gen Sets
FOR SALE

- Solar Maintained - Low Time
- 13 Units (Gen 1) & (Gen 2)
- 8 Natural Gas - 5 Dual Fuel
- Low Nox 25 ppm
- Complete Packages
- Mobile PCR U.G. Switchgear
- 60 Hz ○ 13.8 kV
- 50 Hz Conversion Available

Mid America Engine, Inc.
662-895-8444 · Fax: 662-895-8228
Keith: keith@maegen.com
Art: art@maegen.com

LEASE FOR SALE

For Sale – Oil Lease (Wyoming)
Existing new 160-acre oil field with one (1) well oil field for sale. Well needs remedial work. Estimated recoverable reserves of 113,000 barrels. Lease carries royalties of 25%. "Area of Mutual Interest" letter required. Make offer to Paul at 702-300-1098. Serious inquiries only please.

CONSULTANTS

Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment - 120 specialists upstream, downstream, gas and biofuels. Email: contato@expetro.com.br.
Web: www.expetro.com.br - Rio de Janeiro, Brazil.

PROSPECTS

LARGE RESERVE OIL PROSPECT – NEVADA
– White Pine Co. – 9300' Guilmette test – thick multi-pay w/50 MMBO potential – near oil shows, seeps – 2 seismic closures w/gravity high – solid acreage block – W.I. available – need operator – 81.5% NRI
303 861-2115

E-mail your ad to: glendah@pennwell.com

Advertising Sales / Advertisers Index

Houston
Regional Sales Manager, Marlene Breedlove, 1700 West Loop South, Suite 1000, Houston, TX 77027; Tel: (713) 963-6293, Fax: (713) 963-6228, E-mail: marleneb@pennwell.com. Regional Sales Manager, Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com

Southwest / South Texas/Western States/ Gulf States/Mid-Atlantic
1700 West Loop South, Suite 1000, Houston, TX 77027; P.O. Box 1941 Houston, TX 77251; Regional Sales Manager; Marlene Breedlove, Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com

Northeast/New England/Midwest/North Texas/ Oklahoma/Alaska/Canada
1700 West Loop South, Suite 1000, Houston, TX 77027; Tel: (713) 963-6244, Fax: (713) 963-6228; Regional Sales Manager, Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com.

Scandinavia/The Netherlands/Middle East/Africa
David Betham-Rogers, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France; Tel: 33 2 33 282584, Fax: 33 2 33 274491; David Betham-Rogers, E-mail: davidbr@pennwell.com.

United Kingdom
Carole Winstanley, ADBIZ MEDIA LTD, 252 Union Street, Aberdeen, AB10 1TN, Scotland, United Kingdom; Tel: +44 (0) 1224 791178; Fax: +44 (0) 5601 151590; E-mail: adbizmedia@btconnect.com.

France/Belgium/Spain/Portugal/Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33 (0)1 3071 1224, Fax: 33 (0)1 3071 1119; E-mail: danielb@pennwell.com, France, Belgium, Spain, Portugal, Southern Switzerland, Monaco.

Germany/Austria/Denmark/Northern Switzerland/Eastern Europe/Russia
Verlagsburo Sicking, Emmastrasse 44, 45130, Essen, Germany. Tel: 49 0201 77 98 61, Fax: 49 0201 781 741; E-mail: wilhelms@pennwell.com. Wilhelm F. Sicking, Germany, Austria, Denmark, Northern Switzerland, Eastern Europe, Russia, Former Soviet Union.

Japan
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; Manami Konishi

Brazil
Grupo Expetro/Smartpetro, Att: Jean-Paul Prates and Bernardo Grunewald, Directors, Ave. Erasmo Braga 22710th and 11th floors Rio de Janeiro RJ 20024-900 BRAZIL; Tel: (55-21) 3084 5384, Fax: (55-21) 2533 4593; E-mail: jpprates@pennwell.com.br and bernardo@pennwell.com.br

Singapore/Australia/Asia-Pacific
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; Michael Yee, E-mail: yfyee@singnet.com.sg

India
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. Mr. Rajan Sharma.

Italy
Vittorio Rossi Prudente, UNIWORLD MARKETING, Via Sorio 47, 35141 PADOVA - Italy; Tel:+39049723548, Fax: +390498560792; E-mail: vrossiprudente@hotmail.com

This index is provided as a service. The publisher does not assume any liability for errors or omission.

Real heroes make their own fuel choices

The Editor's Perspective

by Bob Tippee, Editor

Why can't movie stars at least try to live up to their on-screen heroism?

Matt Damon is good, really good, as Jason Bourne in the movie series named for his character—an amnesiac government assassin trying to reconstruct his life while former comrades with nasty secrets chase him from continent to continent.

Damon has a vexed scowl that fits the part like a 9 mm pistol and fake passports fit that safety deposit box in Zurich his character somehow doesn't forget in The Bourne Identity, first in the series. It says, "I know I'm about to remember something important about myself, but first I need to outrun, outsmart, outfight, and eventually blow to public smithereens the killer chasing me, from whose twisted and bloodied corpse I'll stalk away wondering if I should know his name."

Bourne has more humanity than you expect in someone who once sneaked up on people at night with murderous intent. Damon flourishes in the contradiction.

So why does he—just before the third thriller in the series opens—spoil the illusion by acting in real life like a helpless wimp?

Damon and fellow actor Ben Affleck appear in video clips produced recently by the Center for American Progress Action Fund summoning government to action on energy against villainous "big oil."

Dressed as a gasoline pump, Damon calls on Congress and big oil to "mandate cleaner cars and cleaner fuel." Very un-Bourne-like, he says: "A little bit of corn and a pinch of can-do attitude is all it takes. And kids love it, too. Yippee!"

Affleck, playing an ear of corn, promises to bring down big oil, portrayed with astonishing inaccuracy as bullying ethanol out of the fuel market.

As Bourne, Damon is independence personified, ever able, for example, to make a time bomb just when he needs one out of a toaster and magazine.

As himself, Damon invests his reputation in a pitiful plea for governance entitled Clean My Ride, Flex My Fuel.

This is no reason to skip The Bourne Ultimatum, of course. But Bourne will have to be extra self-reliant to overcome what Damon has done to him.

(Online Aug. 3, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Loss followed record high prices

The front-month crude contract ended the trading week through Aug. 3 with a 2% loss after setting record highs in earlier sessions on the New York market.

The September contract for US light, sweet crudes hit an intraday high of $78.28/bbl July 31 on the New York Mercantile Exchange, buoyed by news that US consumer confidence hit a 6-year high in the second quarter. It closed at a record high of $78.21/bbl, up $1.38 for the same day. The previous record closing for a front-month crude contract was $77.03/bbl on July 14, 2006, the same day that the intraday trading set a record of $77.95/bbl.

The crude contract continued climbing in early trade Aug. 1, setting an all-time high of $78.77/bbl on NYMEX. That surpassed the previous high of $78.40/bbl in electronic trading prior to a regular NYMEX session in mid-July of last year. But then the Energy Information Administration reported Aug. 1 a larger-than-expected draw of US crude inventories and large builds in gasoline and distillate fuel stocks during the week ended July 27. That triggered a sell-off that wiped out gains from the July 31 session, with benchmark September crude down to $76.53/bbl by the end of the day.

The contract rebounded to close at $76.86/bbl on Aug. 2 when members of the Organization of Petroleum Exporting Countries reiterated that they see no need to produce more oil when US inventories are 12% above the 5-year average and US refining capacity remains constrained. On Aug. 3, the contract had declined to $75.48/bbl at closing, amid rising fears on Wall Street of a downturn in economic growth.

The front-month crude contract "managed to print a new historical high but it was followed by a quick reversal that brought West Texas Intermediate down for the first week of the last 8" on the New York market, said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. At the end of the week, the crude contract was down $1.54/bbl, reversing the gains of the previous week, while North Sea Brent crude was down a second week in a row, losing $1.51/bbl during the week. The front-month contract for reformulated blend stock for oxygenate blending (RBOB) was down for the fourth consecutive week, and heating oil posted a loss for the third week in a row, Jakob reported.

Energy inventories

US gasoline inventories rose by 600,000 bbl to 204.7 million bbl in the week ended July 27, bigger than Wall Street's expectation for a 100,000 bbl build. Distillate inventories rose by 2.8 million bbl to 126.5 million bbl, compared with a consensus expectation for a 1.3 million bbl build. Crude oil inventories fell by 6.5 million bbl to 344.5 million bbl, well beyond the consensus expectation for a 1.1 million bbl drawdown.

Imports of crude into the US declined by 213,000 b/d to 10.2 million b/d in the week ended July 27. Gasoline imports dropped to 1.2 million b/d from the prior week's record 1.7 million b/d. Distillate fuel imports averaged 339,000 b/d. The input of crude into US refineries increased by 388,000 b/d to 16.2 million b/d in the week ended July 27, the largest input since the week ended Aug. 26, 2005, EIA said.

Analysts at Raymond James & Associates Inc. see signs that OPEC ministers may increase production at their Sept. 11 meeting if crude prices rise too high. If OPEC maintains its current production quota, however, that could result in a fourth-quarter decline in supplies, driving prices up. Raymond James said OPEC production actually increased in July by 850,000 b/d, including a 150,000 b/d hike in Nigeria and an 800,000 b/d decrease in Iran.

At the time of EIA's Aug. 1 report, crude inventories at the key pipeline delivery center in Cushing, Okla., had fallen for 10 consecutive weeks. Jakob said, "The weekly statistics were a reminder that, if underlying demand is not strong enough, a crude oil draw translates into a product build. In July for total products and crude combined, there was a build of 8 million bbl. Gasoline production reached a new record high and is 400,000 b/d higher than the same week last year, while middle distillate production is higher by 490,000 b/d. Refinery runs have [increased] and at the current levels of runs and of imports would cause further severe crude draw downs."

However, he cautioned, "We are starting from US crude stock levels at multiyear highs, and it remains to be seen how long runs can be maintained at the levels of last week when margins are at fall levels and product demand remains moribund."

(Online Aug. 6, 2007; author's e-mail: samf@ogjonline.com)

The New Meaning of FAST

FastMax™—new Tricone® technology

At Hughes Christensen, we've made a habit of defining the industry standard in roller cone bits. Our culture of continuous improvement—based on the industry's biggest R&E spend—delivers the products that give new meaning to performance.

Our R&E team's latest definition for fast is FastMax high-ROP technology. Onshore or offshore, you'll see the difference with

- higher ROP
- fewer bits per section
- better dull condition
- lower drilling cost.

FastMax technology. The industry's first significant steel tooth ROP enhancement in more than a decade.

www.bakerhughes.com/fastmax

BAKER HUGHES Hughes Christensen