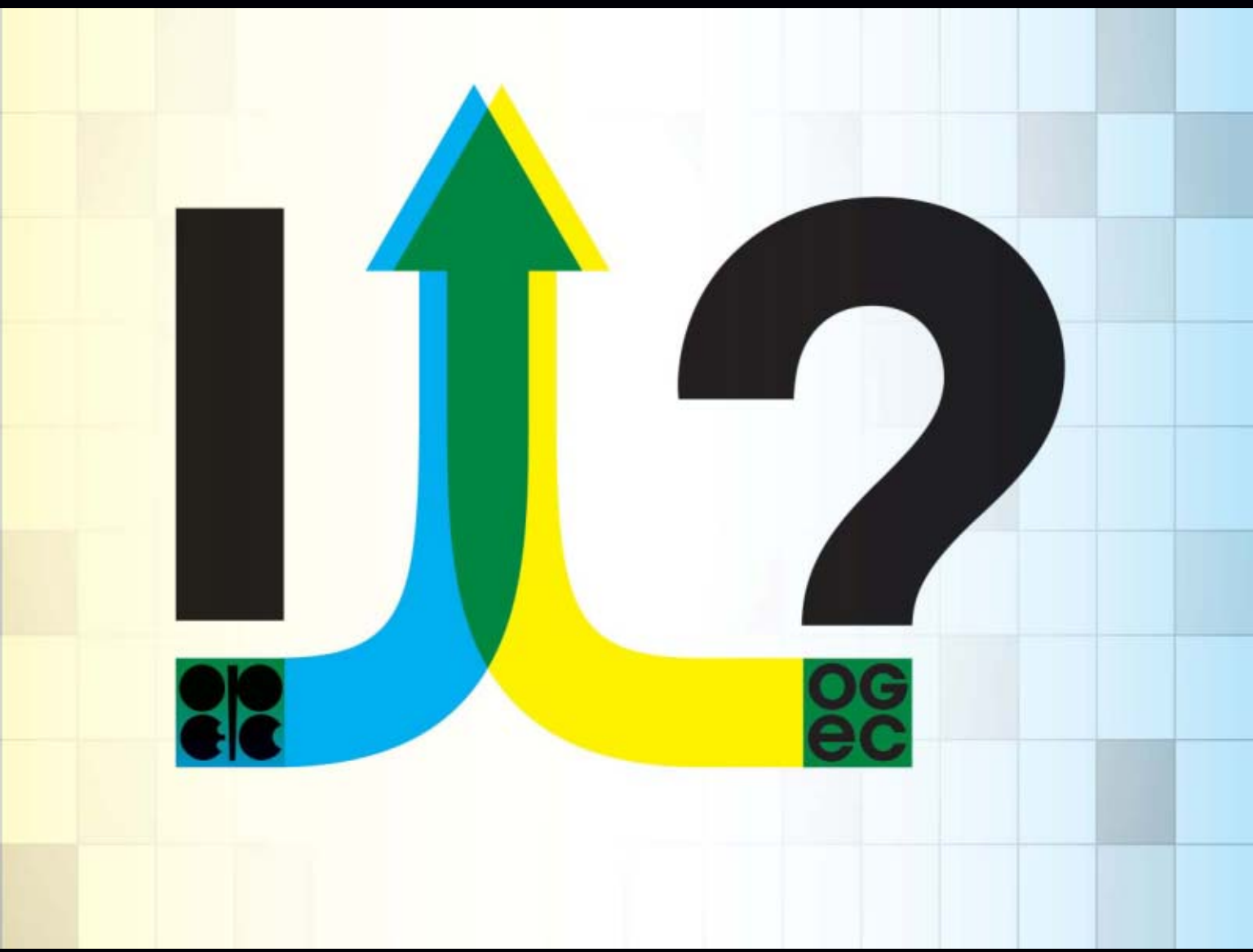
Week of May 28, 2007/US$10.00

PennWell®

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com



OPEC's New Directions

Sudan's oil production, refining capacity climb
Sinai well logging compares TDT, CHFR applications
Offshore processing plant uses membranes for CO_2 removal
Chromatograph, equation yield usable field dewpoint prediction

OIL&GAS JOURNAL®

May 28, 2007
Volume 105.20

OPEC's New Directions

Regular Features

Cover

The Organization of Petroleum Exporting Countries has impacted the price and availability of oil for more than 40 years. Now that natural gas can move farther from source to market via lengthy pipelines and LNG deliveries, there has been talk of a similar organization forming to control gas. Will an OGEC form? If it did, how would it impact current and future plans for costly LNG and pipeline infrastructure? How could gas consumers protect themselves? Many gas-exporting countries are also OPEC members; how much more power could they wield? And where does Russia fit in all this, with its vast gas resources and quest for energy power? These questions and more are answered in the Special Report beginning on p. 22. Cover illustration by Kermit Mulkins.

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. 20) 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

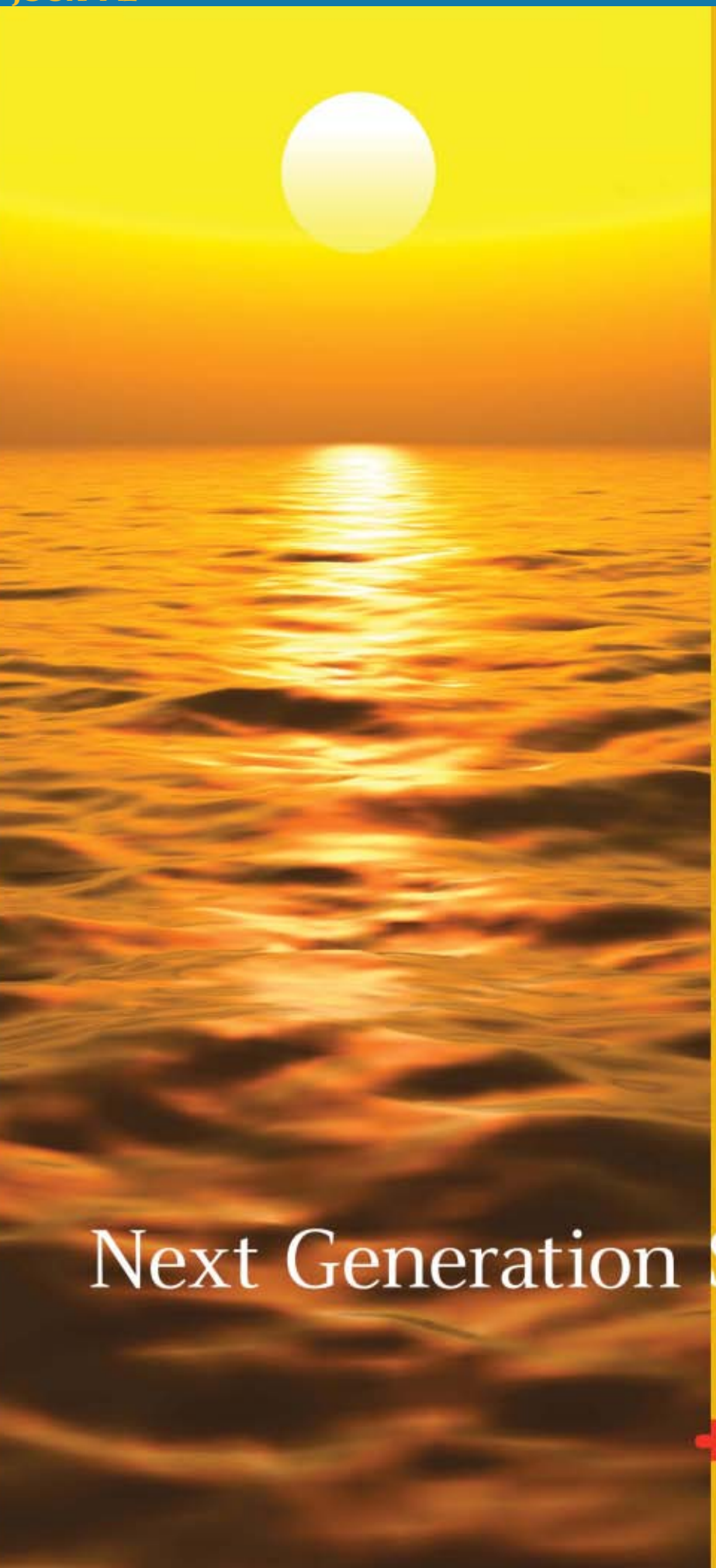
Los Angeles
Tel 310.595.5657
Senior Correspondent Eric Watkins, hippalus@yahoo.com

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



Enabling a New Reality in Offshore Production

With offshore operations moving to deeper fields, remote locations and heavier oil, the ability to process fluids at the seabed can radically change the profitability of your fields.

Next Generation Subsea from FMC Technologies makes it possible to separate oil, gas, water and sand at the seafloor, without the cost of lifting all fluids to the surface. Subsea processing, gas compression and boosting enable efficient transfers of hydrocarbons over greater distances, eliminating the need for offshore platforms in some fields.

The reality? You can boost production and ultimate recovery rates from existing fields and achieve the profitable development of new ones.

Learn more at:
www.fmctechnologies.com

Next Generation Subsea

FMC Technologies

OGJ Newsletter

May 28, 2007

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

General Interest — Quick Takes

UK planning policy to speed energy projects

The UK has launched a white paper to revamp the planning system and ensure that large energy projects of national importance are dealt with quickly, smoothly, and separately from other proposals in the planning program.

Energy companies previously had complained that the planning system—particularly when dealing with major gas projects—was burdensome and that local communities abused the process system by blocking proposals and significantly delaying their timetable.

UK Communities Sec. Ruth Kelly insisted that local communities would have a say in major infrastructure projects at every stage of the process and stressed that the new regime would be accessible to them for voicing their concerns. Companies will now be required to have low-carbon emissions under any new community projects planned.

The new planning system will replace more than eight different planning regimes and could save over £1 billion within 10 years, the UK government said. Ministers and parliament will draw up a new national policy framework to decide how the country's key infrastructure needs for the next 10-25 years will be met under one legal framework. This will be subject to public consultation.

The government has proposed introducing a new independent infrastructure planning commission that would make decisions on nationally significant energy applications, such as LNG terminals and power plants. The commission would comprise "experts of considerable standing and experience drawn from a range of relevant fields," the government said.

Trade and Industry Sec. Alistair Darling said, "Secure, clean energy supplies are vital. Currently major energy projects, including wind farms, can take many years going through the planning system which is confusing and unpredictable for both industry and communities."

Appeals must now be filed within 8 weeks rather than 6 months so they can be dealt with quickly, according to the white paper.

National Grid said that major reform of the planning system was needed and that it would continue to involve local communities in the planning process for its 14 gas and electricity projects that are expected to come on stream by 2012.

E.On welcomed the white paper and urged the government to implement it by 2009 to help facilitate constructing new power stations and renewable schemes. Paul Golby, chief executive of E.On UK said, "The situation is especially pertinent for next generation nuclear power stations and for onshore wind farms, where some of our schemes have been held up in planning for literally years."

Environmentalists were dismayed that major infrastructure projects, such as nuclear power stations and airport expansions, would get the green light under the white paper, arguing that these would harm the environment.

Interested parties have until Aug. 17 to submit comments on the white paper.

DOE staffer pushes renewable technology transfer

The US Department of Energy's renewable energy office is working to accelerate technology transfer as part of an overall effort to improve its outreach to industry, a spokesman said at a recent wind and biofuels conference.

Paul Dickerson, chief operating officer of DOE's office of energy efficiency and renewable energy, said the DOE hired three people having experience as venture capitalists to help accelerate technology commercialization and deployment.

The three visit DOE laboratories and talk with researchers and scientists about ways to provide technology to businesses, said Dickerson. Meanwhile, he schedules weekly meetings between himself and business leaders to discuss technology transfer.

"I have asked the DOE to think differently and to quicken our pace," Dickerson told reporters after he spoke at an energy conference in Houston sponsored by Haynes and Boone LLP on May 19.

"For the first time in our lives, being 'green' is not a partisan issue," Dickerson said. "It is in our vital interests to diversify the United States' energy supply, and the way forward is through technology."

President George W. Bush promotes the use of ethanol in gasoline as a way to help reduce fossil fuel consumption. He has outlined a goal to produce 35 billion gal of renewable and alternative fuel by 2017.

Dickerson called that goal realistic. He said much of the leading-edge fuel technology is being financed by private capital rather than by DOE funding.

Simmons & Co. International analyst Pearce W. Hammond Jr. believes total production of ethanol and biodiesel together could reach only 17.5 million gal by 2017. Other fuel options also will be needed to fulfill Bush's goal, Hammond told the conference.

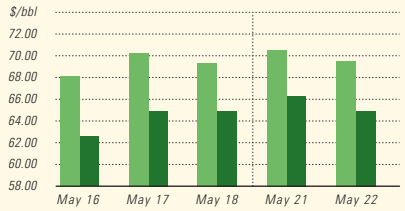
Previously the US Energy Information Administration predicted that the nation's ethanol use will grow to 14.6 billion gal/year by 2030, with corn ethanol accounting for 13.6 billion gal of the total. That projection was made assuming no changes in existing energy policy.

Under the same scenario, EIA predicted US consumption of biodiesel will reach 400 million gal/year in 2030. Last year, the US produced 91 million gal of biodiesel, made primarily from soybean oil.

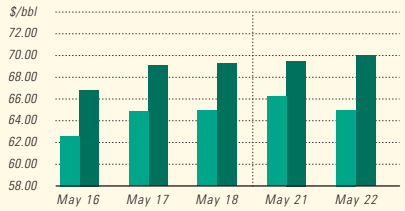
Pamela Beall, Marathon Oil Corp. vice-president of business development, downstream, noted that Marathon is one of the nation's largest blenders of ethanol.

Industry Scoreboard

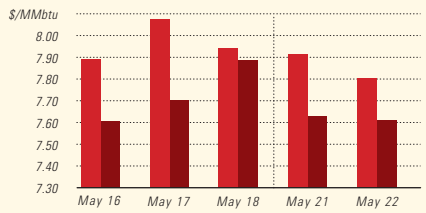
IPE BRENT / NYMEX LIGHT SWEET CRUDE



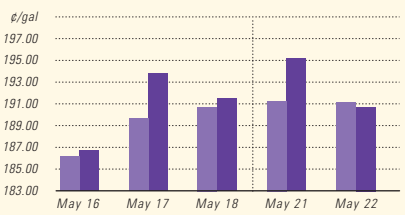
WTI CUSHING / BRENT SPOT



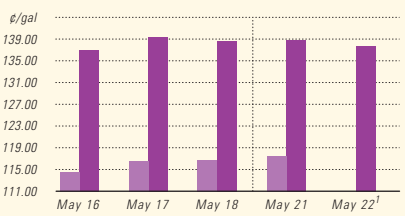
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



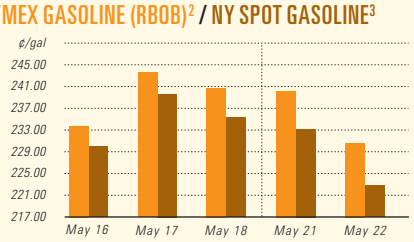
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available
[2]Reformulated gasoline blendstock for oxygen blending

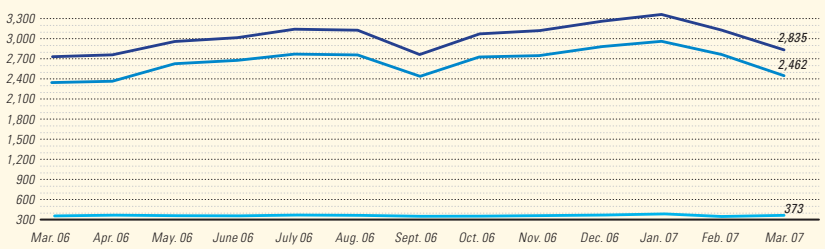
US INDUSTRY SCOREBOARD — 5/28

Latest week 5/18	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	9,163	9,251	–1.0	9,132	9,029	1.1
Distillate	4,177	4,064	2.8	4,377	4,218	3.8
Jet fuel	1,534	1,643	–6.7	1,598	1,585	0.9
Residual	780	629	24.0	753	749	0.5
Other products	4,930	4,775	3.2	4,971	4,772	4.2
TOTAL DEMAND	20,583	20,362	1.1	20,831	20,353	2.3
Supply, 1,000 b/d						
Crude production	5,161	5,088	1.4	5,248	5,056	3.8
NGL production[2]	2,286	2,405	–4.9	2,397	2,168	10.6
Crude imports	10,422	10,072	3.5	9,825	9,890	–0.7
Product imports	3,392	3,816	–11.1	3,216	3,573	–10.0
Other supply[3]	1,114	920	21.0	970	1,102	–11.9
TOTAL SUPPLY	22,374	22,302	0.3	21,656	21,788	–0.6
Refining, 1,000 b/d						
Crude runs to stills	14,933	15,311	–2.5	14,696	14,890	–1.3
Input to crude stills	15,342	15,663	–2.1	15,133	15,231	–0.6
% utilization	88.5	90.0	—	87.3	87.7	—

Latest week 5/18	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	348,960	349,935	–975	342,627	6,333	1.8
Motor gasoline	199,103	201,448	–2,345	209,752	–10,649	–5.1
Distillate	119,540	120,376	–836	117,318	2,222	1.9
Jet fuel	41,158	39,518	1,640	39,230	1,928	4.9
Residual	38,726	38,747	–21	41,709	–2,983	–7.2
Stock cover (days)[4] **5/11**			**Change, %**		**Change, %**	
Crude	22.5	22.4	0.4	22.8	–1.3	
Motor gasoline	21.0	20.9	0.5	22.4	–6.2	
Distillate	28.6	27.8	2.9	28.0	2.1	
Propane	31.8	27.1	17.3	39.0	–18.5	
Futures prices[5] **5/18**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	63.88	62.00	1.88	69.12	–5.24	–7.6
Natural gas, $/MMbtu	7.95	7.75	0.19	6.09	1.86	30.5

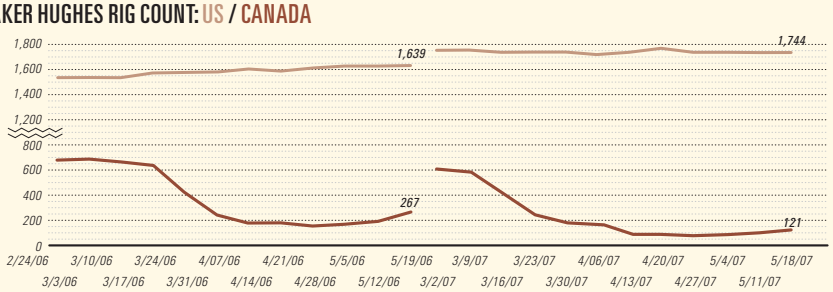
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

We put expandables in your comfort zone

MetalSkin® solid expandable systems reduce installation risks and well construction costs.

New-generation *MetalSkin* open-hole and cased-hole systems feature solid advantages for greater peace of mind.

MetalSkin systems provide more trouble-free installation. An ultraslim design gives more running clearance to avoid ECD problems and differential sticking.

Pipe expansion is far more reliable, using lower expansion pressures and a high-integrity circulation valve. Plus there's a backup expansion system and a unique expansion cone that retracts for retrieval to avoid getting stuck.

Zonal isolation is more positive with elastomer sealing elements. And fully qualified premium metal-to-metal connectors seal the deal.

MetalSkin systems are tailored to your needs and backed by our global expandables network.

Find out more about the world's most advanced expandables. Expand your comfort zone while you reduce well construction costs, mitigate drilling hazards and increase reservoir exposure.

Visit **www.weatherford.com/metalskin**, or contact your Weatherford representative, and see why we're The Solid Choice™ for solid expandable technology.

Our business is built **All Around You.**

Drilling | Evaluation | Completion | Production | Intervention

Weatherford®

Cellulosic ethanol is years away from commercial operations and will not replace corn-based ethanol, Beall said. Renewable fuels will not make energy cheaper, she added.

William Spence, chief executive officer of BioSelect Fuels, Houston, said the biodiesel industry is looking for more feedstock with which to produce biodiesel.

Scientists are researching how to improve crop yields, possibly through genetically modified crops, Spence said, and also are seeking to develop technology enabling a move from food crops for feedstock to nonfood crops.

BioSelect Fuels will operate a biodiesel production and distribution plant in Galveston, Tex. Chevron Technology Ventures LLC, another partner in the project, is part of a joint venture consisting of various investors. The plant is in the process of being commissioned, and it initially will use soy feedstocks.

The facility will have an initial production capacity of 20 million gal/year. Spence hopes the plant can be expandable to 470 million gal/year by 2010 through three sites near refining centers. ✦

Exploration & Development — *Quick Takes*

PTTEP's Gulf of Martaban wells show gas

Thailand's PTT Exploration & Production PLC (PTTEP) said another two exploration wells drilled on Block M9 in Myanmar's Gulf of Martaban have both tested natural gas. The results followed on the success made earlier this year (OGJ Online, Apr. 3, 2007).

Zawtika 3, drilled to 2,274 m TD, encountered eight zones of gas-bearing formation with a total thickness of 65 m, the company said. A tubing stem test was conducted on a selected zone, indicating gas flows of 26.7 MMcfd.

Zawtika 4 reached a 2,390 m TD and found 11 zones of gas-bearing formation with a total thickness of 161 m. A tubing stem test was conducted on two zones, indicating gas flows of 39.6 MMcfd and 31.5 MMcfd.

PTTEP said it plans to drill three additional appraisal wells—Kakonna 2, Zawtika 5, and Zawtika 6—in July. It will then prepare a development plan with sights on starting production in 2011 or 2012.

Falcon to develop Mako Trough in Hungary

Timing remains uncertain, but Falcon Oil & Gas Ltd., Denver, plans to develop a vast basin-centered gas accumulation in southeastern Hungary, where it just announced an oil discovery.

The company, which on May 22 received a long-term oil and gas production license from the Hungarian Mining Authority, said it will "put the necessary systems and personnel in place" to develop its holding in the Mako Trough near the borders with Montenegro and Romania.

The production license covers Falcon's Tisza and Mako exploration licenses totaling 900 sq miles and remains in force as long as the company continues operations, but it was unclear how soon sustained gas or oil production might begin (see map, OGJ, Feb. 6, 2006, p. 40).

The company said its Magyarcsanad-1 well near the acreage's southern extremity discovered oil and gas in the Miocene Endrod formation below 13,000 ft.

Falcon plans to frac the entire 1,188 ft of Endrod that is behind casing after a 23-ft gross interval at 13,310 ft flowed 377 b/d of sweet, 48° gravity oil and 745 Mcfd of gas at 3,843 psi flowing tubing pressure without treatment. Estimated bottomhole temperature is 360° F.

Magyarcsanad-1 is 10¼ miles south of Falcon's Mako-6 well, TD 18,674 ft, which encountered 17,100 psi bottomhole pressure and 460° F. temperature. Mako-7, northwest of Mako-6, set a Hungarian drilling depth record at TD 19,964 ft on Dec. 21, 2006.

Falcon has acquired more than 1,100 sq km of 3D seismic surveys, is drilling its sixth well, and has built a high-capacity gathering pipeline on the acreage. The company has described the Tertiary-age Mako Trough basin-centered gas accumulation, discovered in the 1960s, as the world's youngest.

Consulting engineers in 2006 assessed the acreage as having potential for a contingent resource of 55 tcf of gas, three fourths of which is attributed to the Pliocene Szolnok formation.

Nicaraguan exploration well noncommercial

Norwood Resources Ltd., Calgary, was moving to test its first indicated discovery in the Sandino basin of western Nicaragua after it plugged its second well there as noncommercial.

The company tested eight intervals at the Las Mesas Gutierrez-1 well southwest of Managua. An interval at 3,350-3,460 ft yielded a noncommercial flow of 45° gravity oil.

Intervals at 8,818-38 ft, 8,708-28 ft, and 7,846-8,034 ft tested noncommercial gas flows.

Intervals at 2,770-95 ft, 2,954-3,035 ft, 3,908-56 ft, and 4,742-4,810 ft flowed salt water.

"This well indicates the presence of a positive hydrocarbon basin system (source, maturation, migration and timing of migration including the generation of light oil); and the presence of reservoir rock, as demonstrated by logs, sidewall cores, and water flow rates," the company said.

Norwood is moving to test the San Bartolo Rodriquez Cano-1 well, where it set casing in February. Logs from that well, showed 232 ft of conventional pay and 300 ft of naturally fractured low permeability sands in eight zones below 6,000 ft. Porosities were 17-21% and permeabilities 3 to 30 md (OGJ, Mar. 26, 2007, p. 38).

Murphy Oil lets Thunder Hawk contracts

Murphy Oil Corp. has let several contracts to Intec Engineering for detailed design of flowlines and export pipelines for the Thunder Hawk project on Mississippi Canyon Block 734 in the Gulf of Mexico.

The work has already begun and will be completed by midyear. It includes the detailed design for twin 8-in. insulated flowlines to be installed in 5,710 ft of water. The lines will transport production fluid from the Thunder Hawk subsea development to the host facility, a floating deep-draft semisubmersible to be located 4.5 miles east of the subsea wells on MC Block 736.

Intec also will perform the detailed design work for two 12-in. export pipelines that will transport the separated oil and gas from the host facility to the Mardi Gras transportation system. This detailed design work includes wall thickness selection, cathodic protection design, expansion and lateral buckling analysis, pipeline crossing analysis, and pipeline routing. Also included is the detailed design of the tie-in jumper spools that will connect the export pipelines to existing tie-in sleds on the Okeanos and Proteus pipelines.

Thunder Hawk is scheduled to start oil production in 2009.

Murphy Exploration & Production Co. USA is the lease operator, and its partners include Dominion Exploration & Development Inc., Hydro Gulf of Mexico LLC, and Marubeni Offshore Production (USA) Inc. ✦

Drilling & Production — *Quick Takes*

CNOOC brings WZ 11-1 oil field on stream

CNOOC Ltd. reported start of oil production from Wei Zhou (WZ) 11-1 field in the western South China Sea. The field currently has one well producing more than 2,100 b/d of oil.

WZ11-1 lies southwest of Weizhou Island in 30-40 m of water and next to WZ11-4 and WZ12-1 producing fields.

The one producing platform in WZ11-1 field is tied back to the adjacent WZ12-1 field's production facilities and subsea pipelines.

At peak, WZ11-1 field is expected to produce 7,200 b/d of oil.

CNOOC said marginal fields such as WZ11-1 can be commercialized by sharing facilities with surrounding oil fields. The company has previously developed WZ6-1 field, another marginal field next to WZ11-1, in the same way.

CNOOC Ltd. holds 100% interests of WZ11-1.

Antrim to drill three wells in UK North Sea

Antrim Energy Inc. has secured the services of AGR Peak Well Management of Aberdeen and a drilling rig to facilitate its plans to drill three wells this year in the UK North Sea.

The well sites are about 2 miles southwest of Antrim's 2006 East Causeway discovery, which tested at a combined flow rate of 14,500 b/d of light oil with no water.

Transocean Inc.'s Prospect semisubmersible will drill all the wells, with the first well on schedule to spud the week of May 20, Antrim said. This well is projected to an estimated depth of 11,500 ft and is intended to appraise each of the Jurassic Tarbert, Ness, and Etive sandstones.

The three-well program also will assist in the evaluation of tie-in options for production to nearby facilities.

Meanwhile in Fyne and Dandy oil fields on UK Continental Shelf Block 21/28a, Antrim is acquiring about 70 sq km of 3D seismic data, which is expected to establish an optimum location for development drilling, slated to begin in early 2008.

Petrobras secures semi for work off Brazil

Petroleo Brasileiro SA (Petrobras) has awarded a 5-year, $482 million drilling contract to Pride International Inc. for the Pride Mexico semisubmersible to drill off Brazil.

The contract is to start during second quarter 2008.

Before then, the rig will undergo a 270-day shipyard program and then be moved from the Gulf of Mexico. The $120 million shipyard program includes a previously planned regulatory survey and maintenance, upgrade of the rig's water depth capability to 2,300 ft from 1,100 ft, and modifications to the rig's mooring system and crew quarters.

The contract value includes a performance bonus option of as much as 15%, but it excludes revenues for mobilization, demobilization, and reimbursables. The contract also includes an operating cost escalation provision.

Currently the Pride Mexico rig is mobilizing to a shipyard in Galveston, Tex., having recently completed a 3-year contract off Mexico.

Shell lets Scotford upgrader expansion contract

Shell Canada Ltd. has let a construction and fabrication contract to KBR Inc. for the Scotford upgrader expansion east of Edmonton, Alta. The value of the contract, which will be completed in March 2010, was not disclosed.

KBR will fabricate 160 modules to boost by 100,000 b/d the capacity of the Athabasca Oil Sands Project (AOSP) Expansion 1. Shell plans to increase production from AOSP to 550,000 b/d.

The expansion plan includes adding a third bitumen upgrading train which, along with debottlenecking of the existing facilities, will increase upgrading capacity to 300,000 b/d.

AOSP is a joint venture of Shell Canada 60%, Chevron Canada Ltd. 20%, and Western Oil Sands LP 20%. The group plans to invest $10-12.8 billion in the project. ✦

Processing — *Quick Takes*

Essar Global plans $3.4 billion Egypt refinery

India's Essar Global plans to invest 138 billion rupees ($3.4 billion) to build a proposed 300,000 b/d refinery in northern Egypt. The project likely will be approved, but it is unknown whether Egypt would permit Essar Global to proceed alone or insist in retaining some portion of equity in a project. If approved, the refinery could be on stream by 2010.

Egyptian oil output has declined to 800,000 b/d from peak levels of nearly 1 million b/d in the mid-1990s, and the country is actively encouraging international firms to invest in the oil and gas sector in the country to reverse the declining hydrocarbon output trend.

Egyptian Oil Minister Sameh Fahmy said the country plans to develop recent discoveries in the Gulf of Suez and the Western Sahara. And last month, because of its strategic importance, Egypt

postponed a plan to privatize its 100,000 b/d Middle East Oil Refinery (Midor) in Alexandria.

Essar Global's proposed refinery is part of its plan to have a larger presence in western Asia, where oil-fueled growth and a construction boom have boosted domestic consumption, squeezing supplies to Europe and Asia.

The diversified group also is conducting talks with Iran to develop the country's largest oil field, Azadegan, to fuel a planned refinery and steel plant.

India's state-owned refiner Indian Oil Corp. also has proposed participation in a crude pipeline project from the Mediterranean to the Red Sea coast to allow oil flow to Asia, bypassing the Suez Canal. ✦

Transportation — *Quick Takes*

Oil flow resumes through Nigeria's Bomu manifold

Royal Dutch Shell PLC has resumed pumping crude through the Bomu pipeline manifold in the eastern Niger Delta in southern Nigeria. About 170,000 b/d of production was shut in last week because of community protests.

During the shut-in, Bomu was unable to feed the Bonny export terminal in southern Nigeria.

"Force majeure, however, for May and June contracts still remains in place for Bonny," a Shell spokesman told OGJ. Shell was forced in mid-May to declare force majeure on its contracts after attacks on its facilities.

Nigeria's oil exports have fallen by about 25% over the past year because of continuous attacks on oil infrastructure by militants, which have promised to increase pressure until May 29 when President-elect Umar Musa Yar'Adua takes over from incumbent Olusegun Obasanjo.

The militants see this transition as an opportunity to demand a more equitable distribution of Nigeria's oil wealth.

Statoil installs Tampen link for fall gas deliveries

Statoil AS has installed the 23-km Tampen gas pipeline link between Statfjord field and the UK section of the North Sea preparatory to the delivery of gas from its Statfjord field to the UK beginning Oct. 1. Statoil will hand over its operatorship of the Tampen link to Gassco AS when production begins.

The 32-in. Tampen link delivers Statfjord field gas to the Flags pipeline that extends from Brent field in the UK North Sea to St. Fergus, Scotland. Statoil installed the pipeline using Saipem's Castoro Sei laybarge.

The Statfjord partners will convert three Statfjord field platforms from handling oil with associated gas, to handling gas with associated oil. The work enables Statfjord to continue Statfjord production to 2020, with partners investing just over $2.7 billion.

Statfjord "late-life" additional resources are estimated at 32 billion cu m of gas, 25 million bbl of oil, and 60 million bbl of condensate. The expected recovery ratio is up to 70% for oil and 75% for gas.

National Grid to expand Isle of Grain LNG terminal

Capacity at the UK's Isle of Grain regasification terminal will increase for the third time by another 50% to 14.8 million tonnes/year by 2010-11. The terminal, which has a current capacity of 3.3 million tpy, is undergoing a second expansion to 9.8 million tpy to start in 2008.

National Grid PLC subsidiary National Grid Grain LNG Ltd., which operates the terminal, will invest $612.3 million to boost capacity, positioning the terminal to import one fifth of forecast UK gas demand by 2010. This expansion is in response to the UK's growing need for gas imports and its dwindling supplies from the mature UK North Sea.

Under a $500 million lump-sum turnkey contract, Chicago Bridge & Iron Co. NV will construct a jetty to support LNG vessels with capacity as large as 265,000 cu m and with an unloading rate of 12,000 cu m/hr. CB&I also will build another 190,000 cu m full containment LNG storage tank and gas processing infrastructure.

National Grid has secured long-term contracts with E.On, Iberdrola, and Centrica, each of which have taken all the additional capacity to justify the third expansion.

BP PLC and Algeria's Sonatrach have a 20-year contract for 3.3 million tpy of LNG at Isle of Grain. Long-term contracts for the second phase of expansion have been agreed with Gaz de France, Centrica, and Sonatrach.

Kinder Morgan signs pipeline release agreement

Kinder Morgan Energy Partners LP has entered into a consent agreement with several government agencies to resolve civil claims relating to the unintentional release of petroleum products during three pipeline incidents in northern California.

These releases occurred in the Suisun Marsh area in Solano County in April 2004, in Oakland in February 2005, and near Donner Pass in April 2005.

KMEP has since undertaken a number of operations and pipeline integrity initiatives to prevent similar incidents from occurring in the future. For instance, the Concord-Sacramento pipeline that was involved in the Suisun Marsh incident was replaced in late 2004 as part of a major expansion project and was routed outside the marsh area, KMEP said.

Terms of the agreement state that KMEP will pay $3.7 million in civil penalties, $1.3 million in natural resource damages and assessment costs, and $170,000 in agency response and future remediation monitoring costs. In addition, KMEP agreed to perform enhancements in its Pacific operations relative to its spill prevention, response, and reporting practices, the majority of which have already been implemented.

KMEP has substantially completed remediation and restoration activities at the three sites; remaining restoration work at the Suisun Marsh and Donner Pass areas is expected to be completed later this year. ✦

Deep. Remote. Environmentally sensitive. Situations like this make you appreciate Tenaris R&D.

Tough challenges call for innovative solutions: new products, continuous upgrades, advances in metallurgy. We've already introduced the TenarisBlue® Dopeless™ connection. Our high-strength, corrosion-resistant line pipe takes the worst of sour service, deep-water applications in stride. And there's more. Just watch what we're doing to extend your capabilities, help you drill successfully in complex situations—and make your life easier.

Tubular technologies. Innovative services.

www.tenaris.com

Tenaris

Letters

Taxing creativity

I concur with the position of your editorial "Fuels and political favors" (OGJ, May 7, 2007, p. 17).

However, opposition from "protesting lawmakers" was to have been expected. It is often a normal reaction to successful programs. I recall having developed a salesman compensation program which met all of the vice-president of marketing's desires and had his full approval. At yearend, the program had exceeded all sales goals, contributing to unprecedented profitability at the Williams Cos. fertilizer division. But the executive in charge was extremely displeased: A very few salespersons received total compensation which exceeded his own.

Successful incentive programs should drive creativity to new heights along unexpected paths. ConocoPhillips's venture not only provides a feedstock for biodiesel, it uses waste materials extracted as part of the water purification process at animal processing facilities.

If the current uproar is not overcome, where will it stop? I can anticipate challenges to the Cargill-Ashland venture which will produce chemicals with glycerin waste from agricultural biodiesel production. Yet many biodiesel ventures have wondered how to make that waste disappear through landfill or compost. The Cargill-Ashland venture should be cheered, not attacked. Yet the same rationale used to oppose the ConocoPhillips project may encourage an effort to recapture biodiesel financial incentive from chemical users of glycerin. Where would it stop? Should the distillers' grain (one of the effluents of ethanol manufacture) be taxed? This high-protein byproduct, now far more available due to the ethanol craze, is being substituted for soybean meal in animal rations.

At this rate, the mantra may soon be: "If a profit is being made from unexpected creativity, tax it to oblivion." It sounds ominously like the refrain emanating from Venezuela. Creativity is one of the primary means for this nation to meet its many energy and environmental challenges. Let us not stifle that guiding light every time it brings success.

Gerard d'Aquin
Con-Sul Inc.
Bigfork, Mont

Calendar

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

OIL&GAS JOURNAL online research center

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

MAY

Contract Risk Management for the Oil & Gas Industry Conference, Jakarta, +00 603 2723 6745, +00 603 2723 6699 (fax), e-mail: CindyC@marcusevanskl.com, website: www.marcusevans.com/events/CFEventinfo.asp?EventID=12204. 28-29.

Russia Power Conference, Moscow, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 29-31.

CIS Oil and Gas Summit, Paris, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. May 30-Jun. 1.

SPE European Formation Damage Conference, Scheveningen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 30-June 1.

JUNE

Society of Petrophysicists and Well Log Analysts (SPWLA) Annual Symposium, Austin, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 3-6.

International Caspian Oil & Gas Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: julia.romanenko@ite-exhibitions.com, website: www.caspianoil-gas.co.uk. 5-8.

International Liquefied Petroleum Gas Congress & Exhibition, Nice, 32 2 566 91 20 32 2 566 91 29 (fax), website: www.aegpl.com. 6-8.

Society of Petroleum Evaluation Engineers Annual Meeting, Vail, Colo., (713) 651-1639, e-mail: bkspee@aol.com, website: www.spee.org. 9-12.

PIRA Scenario Planning Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11.

Asian Petrochemicals & Gas Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 11-12.

Central European Gas Conference, Berlin, +44 (0)20 8275 5198, +44 (0)20 8275 5401 (fax), e-mail: CEGC@lynne-evens.com, website: www.thecegc.com. 11-13.

ERTC Refining Management and Strategy Conference, Vienna, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 11-13.

IPAA Midyear Meeting, Henderson, Nev., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11-13.

EAGE/SPE Europec Conference and Exhibition, London, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 11-14.

PIRA London Energy Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 12.

Health and Safety Excellence Conference, Barcelona, +420 257 218 505, +420 257 218 508 (fax), e-mail: healthhandsafety@jacobfleming.com, website: www.jacobfleming.com. 12-13.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-14.

Calendar

Asian Downstream Technology & Catalyst Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 13-14.

IADC World Drilling Conference, Paris, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 13-14.

PIRA Understanding Global Oil Markets Conference, London, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 13-14.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 13-15.

GazChem Conference, Port of Spain, +44 20 7903 2444, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: www.britishsulphurevents.com/Gazchem07_prog.htm. 17-20.

Newfoundland Ocean Industries Association Conference, St. John's, Newf., (709) 758-6610, (709) 758-6611 (fax), e-mail: noia@noianet.com, website: www.noianet.com. 18-22.

Offshore Newfoundland Petroleum Show, St. John's, Newf., (403) 209 3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 19-20.

Brasil Offshore International Oil & Gas Trade Show & Conference, Macae, 55 11 3816 2227, 55 11 3816 2919 (fax), e-mail: contato@brasiloffshore.com, website: www.brasiloffshore.com. 19-22.

PIRA Scenario Planning Conference, Houston, 212-686-6808, 212-686-6628, e-mail: sales@pira.com. website: www.pira.com. 25.

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

API Exploration and Production Standards Conference on Oilfield Equipment and Materials, San Francisco, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 25-29.

PIRA Understanding Global Oil Markets Conference, Houston, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com. website: www.pira.com. 26-27.

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

Power-Gen Europe Conference, Madrid, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 26-28.

Russian Petroleum Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

Moscow International Oil & Gas Conference & Exhibition, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 26-29.

JULY

IPAA OGIS, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11.

✦Carbon Sequestration Development & Finance Summit, Houston, (818) 888-4444, website: www.infocastinc.com/sequest07.html. 11-13.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 18-20.

Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 236-0318, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 25-28.

West China International Oil & Gas Conference, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-27.

International Petroleum & Petrochemical Exhibition, , Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

AUGUST

Coal-Gen Conference, Milwaukee, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 1-3.

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.

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.

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

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.

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.

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.

Come visit us
at Go-Expo 07
June 12 - 14
Booth 4024

X-treme ENERGY GROUP

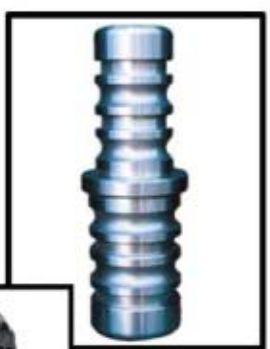
X-treme Energy Group is pleased to announce the purchase and amalgamation of X-treme PDC and Oilfield Tooling, Parkers CNC Machining and Laden Steel Fabrication. Together we have over 100 years of drilling, machining and fabrication experience.

Oilfield Manufacturing

- Complete Drilling Rig Packages
  - Singles, Doubles, Triples
- General Oilfield Manufacturing
- Tanks
- Skids & Platforms
- Buildings

Environmental Services

- Emergency Showers
- Hazardous Waste Storage
- Secure Contained Storage
- Containment Pans
- Pressure Testing Enclosures
- Explosive Magazines



Oilfield Services

- Custom CNC Lathing & Milling
- 5 Axis Milling
- Solid Modeling and Design
- Coring Systems
- Oilfield Rentals
- PDC and Tricone Bits

CWB CERTIFIED

FM APPROVED

ULC

X-treme Energy Group Inc.
Box 6239; 3600 - 61 Ave.
Innisfail, AB Canada T4G 1S9
P. 403.227.5400 F. 403.227.4073

www.xeg.ca

Mixing coffee and crude

Sam Fletcher
Senior Writer

Energy expert Daniel Yergin, the Pulitzer Prize-winning author of The Prize: The Epic Quest for Oil, Money, and Power, a best-seller history of the oil industry, is now appearing in print on hot-drink cups at Starbucks Corp., the coffeehouse chain based in Seattle, Wash., with 7,521 self-operated and 5,647 licensed stores in 39 countries.

The latest publication by Yergin, chairman of Cambridge Energy Research Associates, is a much shorter read than the 877-page Prize. It consists of just two sentences: "To meet the energy challenge requires the most important energy of all—human creativity. That's the real prize."

It may not have the dramatic or defiant ring of "Don't give up the drillship" or "I've just began to drill!" But it's a thought-provoking concept to chew over with a doughnut and a hot cup of Joe.

Yergin's is the 243rd entry in a "The Way I See It" program started in 2005 as "a natural extension of the Starbucks experience," a throwback to the "age-old tradition of the coffeehouse as an egalitarian gathering place where spirited conversation and dynamic debate are the norm," said company officials, who see their coffeehouses as "gathering places for friendly meetings and conversation between friends and neighbors." Yergin's "timely insight" will appear for a limited period of time on the "iconic" white cups in which Starbucks serves its coffee at its North American outlets.

Hand-picked quotes

Company officials hand-pick such "quality roasted quotes from a diverse and extraordinary assortment of individuals, from authors to artists, sports figure to scientists, musicians to politicians, and even local Starbucks baristas [and] customers," they said. All quotes were contributed free of charge and must be "original content," which rules out quotes from books and speeches and limits participation to living persons. Each quarter, 34 new quotes are introduced and remain in circulation until those cup supplies run out.

"We only feature one quote per contributor," said Tricia Moriarty, a Starbucks representative. "All of the white hot-beverage cups in North America carry the quotes—there is no extra cost [for the cups]."

A review board comprising internal Starbucks partners as well as people not employed by the company determines which quotes appear on the cups. "Starbucks looks for original contributions that provoke thought, spark conversation, and initiate debate without being offensive or inflammatory. Contributors are specifically asked to not include indecent speech, hate speech, or ad hominem attacks. Starbucks also asks that contributors consider that some issues might be too big to be properly handled in such a small forum, or too divisive to be respectfully treated on the back of a coffee cup," officials said.

It's good to know that energy is not too big or too divisive a subject for such a forum. "We have featured quotes on many, many different topics including energy and the environment," a Starbucks representative told OGJ. However, company officials could not say how many times energy and the environment have been featured on their coffee cups. Nor could anyone confirm if former Vice-President Al Gore has yet been quoted.

"It is a great honor to be selected for this program," Yergin said in a joint release. "Starbucks provides a unique way to communicate with millions of its customers across North America, in a daily moment of calm, about the global energy challenges and the human spirit that will respond to it." He said, "A great bubbling and brewing of energy innovation is now taking place, and where better to reflect upon it than over a brew at Starbucks." Yergin previously coined that term, "the great bubbling" to describe the widespread technological response to the energy challenge.

It might prove symbolic if, thanks to Yergin's inspiration, Starbucks coffeehouses do become neighborhood centers for the discussion and resolution of energy issues in North America. Coffeehouses have been social gathering places in Middle Eastern countries since the 16th century. They became popular in Europe with the introduction of coffee in the 17th century. In England, where coffeehouses were open to all regardless of social status, they became identified with equality and republicanism. Eventually they became meeting places for businessmen. Lloyd's of London began in a coffeehouse where underwriters of ship insurance met to do business.

So maybe Starbucks could become a clearinghouse for North American energy issues. Of course, it might seem odd complaining about record retail gasoline prices of $3.209/gal while quaffing coffee priced at the equivalent of $28/gal. But then how often do any of us buy coffee in 10-20 gal lots? ✦

Editorial

OPEC's changes

Much of what has been written about the Organization of Petroleum Exporting Countries lately concerns not the group but the model. As demand grows worldwide for natural gas, the question arises: Can a global cartel of gas producers form with enough control over supply to influence price? The special report starting on p. 22 examines the issue.

Most other questions about OPEC focus on immediate conditions in the oil market. How will political unrest affect production in restive members such as Nigeria and Venezuela? Will the group predict demand accurately and make timely adjustments in production?

Questions such as those are now the routine because OPEC, contrary to lingering prejudices, has become a steadying influence in the market. The group regularly parries the lurches of its maverick members and has settled into its role as the oil market's balancing mechanism. While internal politics can be testy, OPEC as a whole has learned from its mistakes and improved its ability to anticipate and adjust production to requirements for members' crude. That the group sometimes misreads market signs hardly makes it unique.

Stability, though, is not stasis. OPEC is changing.

Adding members

Most obviously, membership of the group is growing. In January, Angola, with its 1.6 million b/d of production, became a member. Sudan, with 300,000 b/d of production, wants to join. Ecuador, which produces 500,000 b/d, might rejoin after having left the organization in 1992. New members increase OPEC's market share and, therefore, its leverage. They also represent new bundles of interests that must be accommodated when the group tries to coordinate production.

Divergence of interest is the bane of any cartel. The problem seems minor when, as now, the oil market absorbs most of what OPEC members can produce. But conditions change. The next time OPEC needs to apportion production cuts across the membership, an expanded roll will complicate the politics. So will another important influence on the group's character: the contrast between members able to increase production capacity and those with no hope for output gains.

Another often-overlooked but important trend in OPEC is the steady growth of members' production of natural gas liquids. In its May Oil Market Report, the International Energy Agency says OPEC output of NGL might rise by 7.8%/year to reach 7.1 million b/d by 2012. There are several reasons for the expected increase, most having to do with burgeoning gas production and antiflaring programs. Most significant about the increase is that OPEC quotas don't apply to NGL. In the context of quota pressures, OPEC NGLs represent, to OPEC, competitive supply.

In international affairs, OPEC frequently expresses concern about security of demand, the reciprocal of the supply-security worries voiced regularly by industrial consuming countries. For OPEC, security of demand has a vital financial component. Members able to expand capacity must make immediate decisions about the enormous investments required if they're to meet projected demand for their crude oil years and decades from now. They naturally worry when politicians in the US and other consuming countries make diminished reliance on foreign oil a touchstone of energy policy. At present, the mutuality of interest between buyers and sellers gets little attention as a source of security. Still, an opportunity for international cooperation presents itself here.

Iraq and OPEC

Looming over all matters pertaining to OPEC is Iraq. Still exempt from group quotas, the beleaguered country struggles to produce 2 million b/d. Key pipelines and production equipment remain subject to attack by insurgents. Insecurity precludes oil-field modernization. Work on a hydrocarbon law has stalled over regional politics. The government wants to take a 2-month vacation.

But Iraq's travails, deadly and drawn out as they have been, can't last forever. Not everyone has given up hope for peace and prosperity for Iraqis. With stabilization, wherever that might lie in the future, comes a renewal of prospects for the 6 million b/d of oil output of which the country surely is capable.

When Iraq realizes its production potential, OPEC will be a different organization than it is now—and hopefully not much older. ✦

Held under the Patronage of
H.E. Dr. Abdul Hussain Bin Ali Mirza, Minister of Oil & Gas Affairs,
Chairman-National Oil & Gas Authority, Kingdom of Bahrain

PIPELINE REHABILITATION & MAINTENANCE ™

Co-Hosted by:

Supported by:

Co-located with:

CALL FOR ABSTRACTS

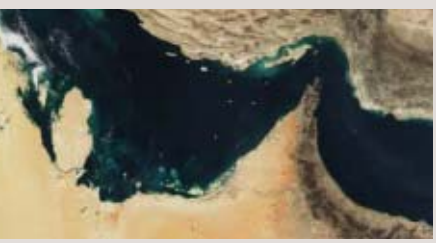
Few of the world's oil and gas regions are as hard on field equipment as the Middle East. At the same time, the region's importance in supplying oil and natural gas to the rest of the world has only increased in recent years and critical in the movement of hydrocarbons from field to market are the region's oil and gas pipelines, the integrity of which is the focus of ongoing research and development.

The tools and technologies that are the fruits of the research and the accounts of how pipeline operators have dealt with maintenance issues form the core of this conference.

This event has established itself as the leader in bringing together major operating and service companies and their technical and management personnel to learn the latest and best in pipeline rehabilitation and maintenance.

ADVISORY BOARD

www.pipeline-rehab.com



Bahrain International Exhibition Centre, Manama, Kingdom of Bahrain
9–13 December 2007

TECHNICAL OVERVIEW:

- Pipeline construction in challenging soil environment (such as Sabkha)
- Pipe manufacturing and metallurgy
- Rehabilitation methods and material technology
- Risk assessment and area classification
- HAZOP (hazard and operability) studies,
- security and integrity
- Leak detection and cathodic protection systems
- Inspection of CP systems
- Inline inspection and development of repair plans
- Risk assessment and preventive measures
- Offshore pipeline inspection, repair and rehabilitation
- Selection of valves
- Project Management

CALL FOR ABSTRACTS DEADLINE 18 JUNE 2007

Opportunities now exist to submit paper abstracts for consideration, with actual case study presentations being of particular interest.
Please forward your title and 150 – 200 word abstract and list all the authors.
Full contact information for the primary contact author (company affiliation, telephone, fax number and email address) must be provided.

Please submit a 150–200 word abstract online or via email to **Frances Webb, Event Director, by 18th June 2007.**
Online: www.pipeline-rehab.com
Email: francesw@pennwell.com

EVENT DIRECTOR

Frances Webb
Tel: +44 (0) 1628 810562
Email: francesw@pennwell.com

SALES ENQUIRIES

Craig Moritz
Tel: +1 713 499 6316
Email: craigm@pennwell.com

Jon Franklin
Tel: +44 (0) 1992 656658
Email: jfranklin@pennwell.com

Jane Bailey
Tel: +44 (0) 1992 656651
Email: janeb@pennwell.com

Owned and Produced by: PennWell

Flagship Media Sponsors: Oil, Gas & Petrochem EQUIPMENT | OIL&GAS JOURNAL | Offshore

Could a future gas OPEC shape LNG import plans?

David Wood
David Wood & Associates
Lincoln, UK

The Organization of Petroleum Exporting Countries has influenced both the supply and the price of oil internationally for more than 30 years. Many commentators, consumers, and politicians in Organization for Economic Cooperation and Development (OECD) countries consider the rise of the cartel's power to be a consequence of their countries' becoming dependent on imported energy supplies to fuel growing economies.

OECD countries in East Asia and many in the European Union decades ago also had to come to terms with a dependence on imported natural gas.

In recent years the US and the UK have recognized a future that requires increasing gas imports to fill widening domestic supply gaps caused by increasing demand, primarily for power generation, along with the simultaneous decline of domestic reserves and production.

Many in the US and the EU are associating OPEC's rise and subsequent many-fold oil price increases for consuming nations with a potential for the formation of a similar natural gas cartel of main gas reserve holders and producers—an OPEC-like Organization of Gas Exporting Countries (OGEC).

It is important to explore such an argument because the prospect is used, particularly by some in the US, to argue against building extensive additional LNG import capacity.

Furthering this apprehension, the world's leading gas exporting nations met this April at the Gas Exporting Countries Forum (GECF) in Qatar and, with Russia as driver, agreed to establish a group to evaluate "gas pricing implications for gas exporters" and "cooperation to stabilize the market," viewed by some as another step towards the creation of an OGEC.

Although the GECF includes the more-market-friendly nations of Qatar and Nigeria, it is the Russian, Iranian, Venezuelan, and Algerian contingent that is striving for a cohesive "gas OPEC" that can command an export price for gas that reflects its "real" value.

There are several relevant factors that influence how, when, and if a cartel of producing gas nations might form and the control it might leverage over supply and prices. Considered here are some of those factors and a comparison of the circumstances of the global oil and natural gas industries.

Who controls reserves?

Tables 1 and 2 summarize the latest BP Statistical Review statistics for June 2006 proved gas (Table 1) and oil (Table 2) reserves at yearend 2005, ranking the top 25 countries in descending order according to their reported holdings of gas and oil. In Table 2 the 12 OPEC countries are boldfaced.

Comparisons between the two tables are illuminating. The cumulative reserves column reveals how many countries together control what percentage of proved reserves worldwide. Although the broader distribution of reserves incorporating the lesser categories of reserves and potential resources provide the full long-term picture, proved reserves are those that are most likely to be converted into production in the medium term and will serve here to make the necessary points.

Tables 1 and 2 reveal striking

similarities in the ranking of the largest reserves holders, particularly the top 10 nations.

Eight nations appear as the top 10 reserve holders of both oil and gas. Seven of these—Saudi Arabia, Iran, Iraq, Venezuela, Algeria, the UAE, and Nigeria—are OPEC members, and the other is Russia, which dwarfs the other countries in terms of its gas reserves much as Saudi Arabia dwarfs the other nations in terms of its oil reserves.

The US is 6th on the list for gas and 11th for oil, but it is rapidly dropping on both lists because of the way it has effectively exploited and consumed domestic oil and gas over past decades. Apart from the eight countries mentioned and the US, two others appear in the top 10 on one list and rank high on the other list: Qatar ranks 14th for oil and 3rd for gas, and Kazakhstan ranks 8th for oil and 11th for gas. Two others are much more oil-rich than gas-rich: Kuwait ranks 4th for oil and 21st for gas, and Libya is 9th for oil and 22nd for gas, although results of the current phase of exploration in Libya may yet change its position.

GLOBAL PROVED NATURAL GAS RESERVES*

Table 1

Rank	Country	Tcf	Trillion cu m	Share of total, %	Cumulative share of total, %	Reserves/ production (R/P), years
1	Russian Federaton	1,688	47.8	26.6	26.6	80.0
2	Iran	944	26.7	14.9	41.5	>100
3	Qatar	910	25.8	14.3	55.8	>100
4	Saudi Arabia	244	6.9	3.8	59.6	99.3
5	UAE	213	6.0	3.4	63.0	>100
6	US	193	5.5	3.0	66.0	10.4
7	Nigeria	185	5.2	2.9	68.9	>100
8	Algeria	162	4.6	2.5	71.5	52.2
9	Venezuela	152	4.3	2.4	73.9	>100
10	Iraq	112	3.2	1.8	75.6	>100
11	Kazakhstan	106	3.0	1.7	77.3	>100
12	Turkmenistan	102	2.9	1.6	78.9	49.3
13	Indonesia	97	2.8	1.5	80.5	36.3
14	Australia	89	2.5	1.4	81.9	67.9
15	Malaysia	88	2.5	1.4	83.2	41.4
16	Norway	85	2.4	1.3	84.6	28.3
17	China	83	2.4	1.3	85.9	47.0
18	Egypt	67	1.9	1.1	86.9	54.4
19	Uzbekistan	65	1.9	1.0	88.0	33.2
20	Canada	56	1.6	0.9	88.8	8.6
21	Kuwait	55	1.6	0.9	89.7	>100
22	Libya	53	1.5	0.8	90.5	>100
23	Netherlands	50	1.4	0.8	91.3	22.3
24	Azerbaijan	48	1.4	0.8	92.1	>100
25	Ukraine	39	1.1	0.6	92.7	58.7
Sum of top 25 countries		**5,885**	**166.7**	**92.7**		
Rest of world		**463**	**13.1**	**7.3**		
Total world		**6,347.79**	**179.82**	**100**	**100**	**65.1**

*On Jan. 1, 2006.
Sources: BP Statistical Review, June 2006, David Wood & Associates

PROVED GLOBAL OIL RESERVES[1]

Table 2

Rank	Country	Billion tonnes	Billion bbl	Share of total, %	Cumulative share of total, %	Reserves/ production (R/P), years
1	**Saudi Arabia[2]**	36	264.2	22.2	22.2	65.6
2	**Iran**	19	137.5	11.5	33.7	93.0
3	**Iraq**	16	115.0	9.5	43.2	>100
4	**Kuwait**	14	101.5	8.5	51.8	>100
5	**UAE**	13	97.8	7.9	59.7	97.4
6	**Venezuela**	11	79.7	7.0	66.7	72.6
7	Russian Federation	10	74.7	6.2	72.9	21.4
8	Kazakhstan	5	39.6	3.3	76.3	79.6
9	**Libya**	5	39.1	3.1	79.4	63.0
10	**Nigeria**	5	35.9	3.0	82.3	38.1
11	US	4	29.3	2.2	84.5	11.8
12	Canada	2	16.5	1.4	85.9	14.8
13	China	2	16.0	1.3	87.3	12.1
14	**Qatar**	2	15.2	1.2	88.5	38.0
15	Mexico	2	13.7	1.1	89.7	10.0
16	Brazil	2	11.8	1.0	90.6	18.8
17	**Algeria**	2	12.2	0.9	91.6	16.6
18	Norway	1	9.7	0.8	92.4	8.9
19	**Angola**	1	9.0	0.7	93.1	19.9
20	Azerbaijan	1	7.0	0.6	93.7	42.4
21	Sudan	1	6.4	0.5	94.2	46.3
22	India	1	5.9	0.5	94.7	20.7
23	Oman	1	5.6	0.5	95.2	19.6
24	Ecuador	1	5.1	0.4	95.6	25.5
25	**Indonesia**	1	4.3	0.4	96.0	10.4
Sum of top 25 countries		**157**	**1,152.5**	**96.0**		
Rest of world		**7**	**48.2**	**4.0**		
Total world		**164**	**1,201**	**100**	**100**	**40.6**

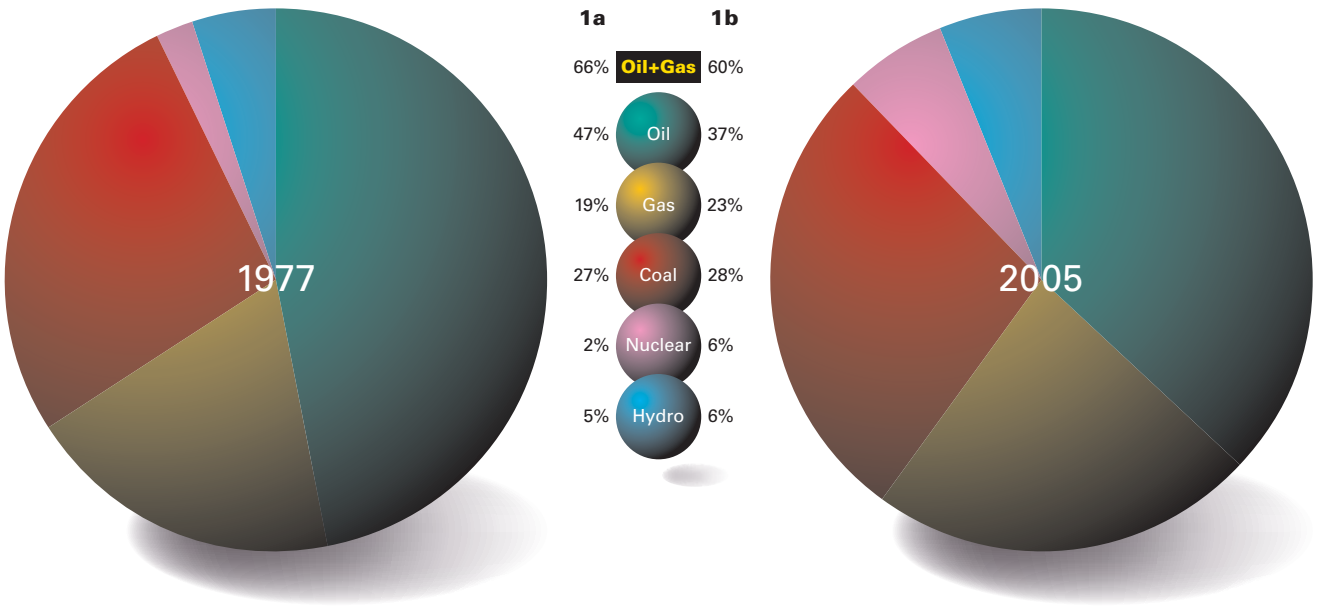
[1]On Jan. 1, 2006. [2]OPEC member countries are highlighted.
Sources: BP Statistical Review, June 2006, David Wood & Associates

What these statistical rankings emphasize is that it is essentially the same group of countries that control the bulk of proved global oil and gas reserves. If reserves holdings were the only factor considered, they probably could have formed a gas cartel a decade or so ago.

However, it is the Russian Federation's position that stands out in both

WORLD CONSUMPTION OF PRIMARY ENERGY

Fig. 1



Sources: BP Statistical Review, June 2006, David Wood & Associates

tables: Together with Kazakhstan, it is the only non-OPEC member in the top 10 ranking for oil reserves, and it is at the top of the rankings for gas reserves, controlling more than 25% of the world's resource. Despite its other mineral riches Russia remains a petro-economy, historically booming when prices are high and suffering economic crisis when oil prices collapse, such as during the major recession in 1998.

Russia's gas market role

Russia has remained outside of the OPEC cartel. If geopolitics in the days of the Soviet Union had been different, however, it could easily have become an OPEC member in the 1970s. Along with other non-OPEC oil producing nations, Russia certainly has been quick to exploit oil export supply shortages and price increases. It has been able to benefit more from being outside OPEC and responding to oil supply and demand circumstances on its own rather than as part of a group.

From the OECD perspective, Russia has a huge influence on global oil supply whether it is in or out of OPEC, and its inability to sustain year-on-year production growth of nearly 10% that it achieved during 2000-04 has partly influenced the high oil price environment of the last few years. It is not necessary for such a large reserve holder to be part of a cartel to make its mark on the oil industry, particularly when supply is tight.

Russia's position for gas is even more dominant, and should a gas cartel form, Russia would have to be part of it for it to be effective on a global scale. Indeed gas reserves are even more tightly held than oil. Russia, Kazakhstan, Turkmenistan, and Uzbekistan together hold 30.7% of global proved gas reserves. Russia already controls gas supply from those countries to a great degree through infrastructure holdings and access to Western Europe.

By adding Iran and Qatar, a cartel of six nations could be formed, straddling parts of central Asia and the Middle East in one contiguous geographic block that controls some 60% of global proved gas reserves—the same percentage that Middle East OPEC nations control of the world's oil.

By adding the North African producers—Algeria, Egypt, and Libya—along with Saudi Arabia and Nigeria, another 10% of global gas reserves could be controlled. It is certainly possible therefore, in volume and geographic terms, to conceive of a gas cartel, led by Russia, with as much resource might as OPEC holds in the oil sector.

So why has such a cartel not emerged? The different structures of the oil and gas industries, geopolitics, markets, and the consuming nations' use and dependence on gas all play a role in answering this question.

PRIMARY GLOBAL ENERGY MIX

Table 3

	1977		2005	
	Million toe*	Total, %	Million toe*	Total, %
Oil	2,946	46.8	3,837	36.4
Gas	1,173	18.6	2,475	23.5
Coal	1,725	27.4	2,930	27.8
Nuclear	121	1.9	627	6.0
Hydro	337	5.4	669	6.3
Total	**6,302**	**100**	**10,537**	**100**

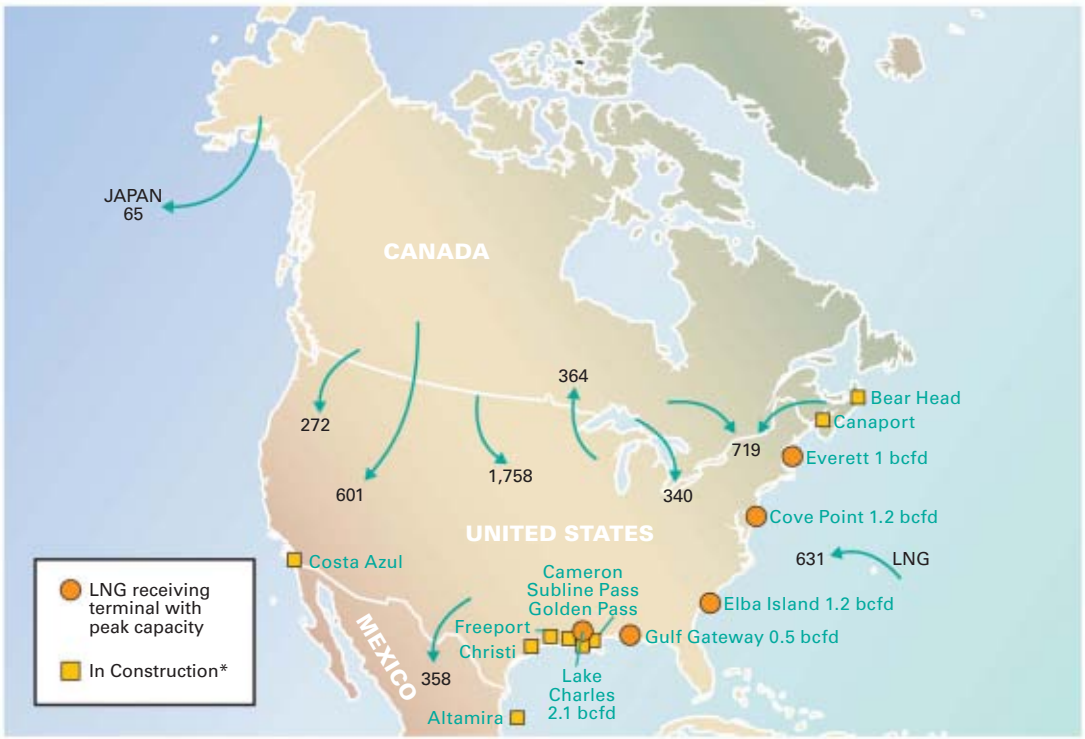
*Million tonnes of oil equivalent.
Sources: BP Statistical Review June 2006, David Wood & Associates

Oil vs. gas dependence

Figs. 1a and 1b compare the contributions that differ-

US 2005 GAS IMPORTS, EXPORTS, BCF

Fig. 2



*Expected to be operational by 2010.
Sources: US Energy Information Administration 2006, Canada's National Energy Board 2006, David Wood & Associates

ent energy sources made to the world's primary energy consumption mix in 1977 and 2005.

In the 1970s when OPEC began to exert an extraordinary influence on the oil industry, the world depended on oil for almost half of its energy requirements. Oil was used for power generation, transportation fuel, and as a petrochemical feedstock to create nonenergy products such as plastics, solvents, and paint. It was difficult to imagine how any modern economy could function or grow without access to a plentiful supply of oil.

OECD countries had grown accustomed to having ample supplies of cheap oil as a legacy from its colonial past.

In the 1970's natural gas amounted to less than 20% of the primary energy mix, and few nations—OECD plus Russia—consumed it in substantial quantities. Gas was used almost exclusively for power generation and space heating.

Today, although oil's use is reduced in percentage terms, it continues to dominate other forms of energy worldwide, particularly for transportation fuels, and it still vastly outweighs the world's dependence on gas.

Table 3 shows that global consumption of gas, however, has more than doubled in absolute terms since the 1970's, growing more rapidly than any other primary energy source in the past 15 years, whereas oil use has increased some 30% since the 1970s.

Although gas clearly is raising its profile and significance, it has a long way to go to rival that of oil. Moreover, with current infrastructure, it is easier to substitute alternative energy sources to replace gas for power generation, as required, than it is to replace oil for certain transportation fuels, such as aviation fuel, and for specialty petroleum products.

To achieve the impact and magnitude of control that OPEC has maintained over oil supply requires a lack of readily available substitutes and a dominant position in an environment of growing energy demand. Gas has yet to achieve such status in a global context, but could yet do so in the next 2 decades as oil supply becomes tighter and gas increases its share of the global energy mix.

Gas markets also are being diversified, with gas-to-liquids (GTL) projects producing Fischer Tropsch middle distillates, methanol, and dimethyl ether (DME) and gas being used as a source for hydrogen to fuel cells for transportation and embedded power generation projects.

However, such markets are likely to remain small for the next decade at least, and it is hard to see gas rival oil in any transportation market in the short term. The significance is that it diminishes the ability of a gas-producers

2005 US GAS IMPORTS AND EXPORTS

Table 4

	Volume, bcf
Imports	
Canada	3,690.0
Trinidad and Tobago	439.4
Algeria	97.0
Egypt	72.5
Malaysia	8.7
Nigeria	8.2
Qatar	3.0
Oman	2.5
Total	**4,321.3**
Exports	
Canada	364
Mexico	358
Japan, as LNG	65
Total	**787**

Sources: EIA 2006, NEB 2006, David Wood & Associates

Enter the future of online crude oil trading.

Traded on DME Direct™. Cleared by NYMEX.

The Dubai Mercantile Exchange Limited (DME) recently announced that its futures contracts will be traded on DME Direct™, its advanced, online trading system. Soon, the industry will have a secure and transparent means of accessing the world's first listed, physically delivered Middle East sour crude oil, the Oman Crude Oil Futures Contract.

DME Direct's proven technology will enable trading virtually 24 hours a day, providing the world with a new, online energy to trade.

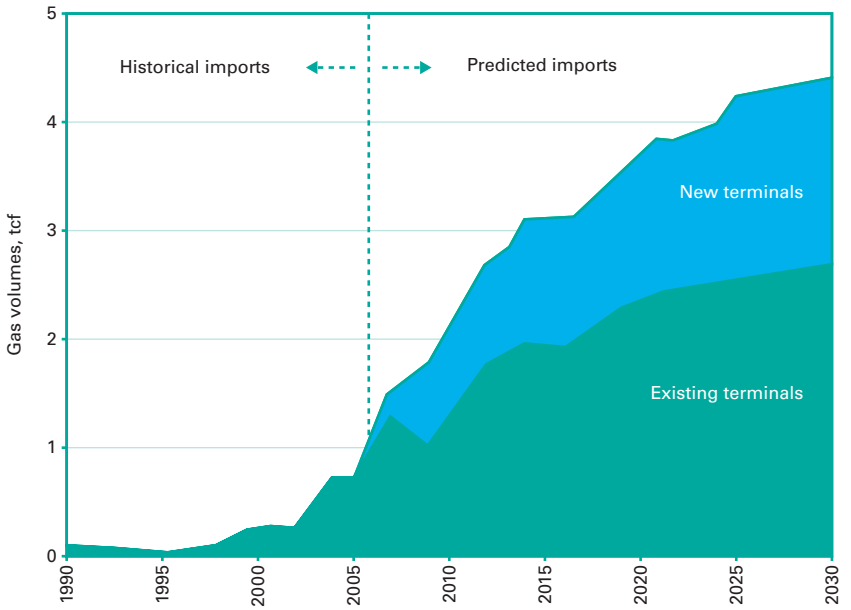
The Dubai International Financial Centre - P.O. Box 66500 - Dubai, United Arab Emirates
Tel: +971 4 365 5500 - **Fax**: +971 4 365 5599 - **Email**: info@dubaimerc.com - **www.dubaimerc.com**

The Dubai Mercantile Exchange Limited's (DME) establishment of an exchange inside the Dubai International Finance Centre (DIFC) is subject to regulatory approval from the Dubai Financial Services Authority (DFSA) to be licensed as an Authorised Market Institution to operate as an exchange inside the DIFC. Furthermore, all clearing and settlement services to be provided by the New York Mercantile Exchange to the DME are subject to the New York Mercantile Exchange becoming recognised by the DFSA to operate a remote clearinghouse in the DIFC and subject to the review and/or approval of the Commodity Futures Trading Commission. Until the above regulatory approvals have been granted, no trading on the DME will be permitted and no person will be admitted as a member of the DME.

DME
Dubai Mercantile Exchange
Cleared by NYMEX
Energy to Trade

US LNG IMPORT VOLUMES, LOCATIONS TO 2030

Fig. 3



Sources: EIA Annual Energy Outlook 2006, David Wood & Associates

cartel to influence the energy markets because any effort to constrain supply would result in consumers moving to alternative power generation fuels and emerging GTL industries being mothballed as uneconomic.

Gas markets regional

The world's gas markets are not like the global crude oil market. Gas is less fungible than oil and is mostly traded regionally under long-term contracts. In addition, because of its physical properties, gas is much more difficult and expensive to transport and store. These high-cost and rigid supply chains do not lend themselves easily to manipulation by suppliers.

The highly seasonal nature of gas demand also distinguishes it from oil; most major consumers are in high-latitude, northern hemisphere regions.

A substantial amount of oil is traded on short-term and spot market contracts against the three major benchmark crudes Brent, West Texas Intermediate, and Dubai-Oman, underpinning futures trading on exchanges and interregional movements and arbitrage of physical marine tanker cargoes of crude oil.

However, for the most part, gas supply and trading is limited to strict regionally defined markets, e.g., Europe, North America, and Asia, each with its own distinct fundamentals, contract types, and pipeline or LNG supply chains. This makes it difficult to move gas parcels between regional markets.

We are a long way from being able to talk about a global gas market. LNG does theoretically offer the potential to move, trade, and divert cargoes of gas into more profitable markets, and some cargoes are traded in this way.

However, it is worth placing short-term gas trading in context. In 2005, about 721.45 billion cu m of gas was traded internationally, according to the BP Statistical Review, June 2006. Of these volumes, 532.65 billion cu m (74%) were shipped by pipeline, and 188.8 billion cu m (26%) were shipped as LNG. About 11% of the LNG exported was traded under short-term contracts—about 2.9% of the international gas trade.

Clearly there is a long way to go before gas can be considered a free-trading, global commodity. Even with further gas market liberalization and expanding trading opportunities, most industry analysts do not expect short-term LNG trading to account for more than 20% of LNG trade by 2020.

Gas is traded on long-term contracts primarily due to the high cost of the infrastructure, which can cost several billion dollars to establish an intercontinental supply system. To fund such facilities requires a substantial amount of capital and particularly debt capital in most instances. This means that financial institutions are supporting much of the international infrastructure being built to handle gas, whether it is by pipeline or as LNG or GTL.

The projects require guaranteed long-term revenue streams to support debt repayment schedules and therefore are underpinned by long-term offtake contracts, commonly 10-25 years, with onerous take-or-pay and send-or-pay clauses.

In such circumstances the borrowers, i.e., operators and owners, usually incorporating governments and state-controlled companies in joint ventures with international companies, have to post security and issue stringent guarantees to secure the financing. If the projects are shut down for any reason, including governments interrupting supplies to extort higher payments for the gas, financial institutions retain the option to call in their loans.

Repercussions in terms of lower credit ratings and restrictions of future international inward investment could be potentially punitive for governments triggering default on long-term gas supply contracts. Such contractual obligations act as major disincentives for governments to unilaterally attempt to manipulate supply or to breach contract volume quotas and prices. The foregoing all implies that a GCEF or an OGEC might not be able to influence regional gas markets and their gas prices very easily.

Supply diversification

Cost and debt funding are not the only drivers for long-term contracts in the gas industry. Security of supply for the gas-consuming nations is another key factor. Japan, for example, was

badly impacted by the oil shortages that resulted from the oil crises that OPEC created in the 1970s.

To improve the security of its gas supply, Japan entered into a series of long-term contracts with a diverse range of international LNG suppliers in subsequent decades.

To further improve its security and control its supply, Japan's state-controlled utility companies have taken equity positions upstream along the supply chain, all the way back to remote gas fields in some cases.

Subsequently, South Korea and more recently China have adopted similar models. Each consumer nation is taking steps to become involved in the upstream gas chains supplying gas from the Middle East, Far East (Brunei, Indonesia, and Malaysia) and Australia.

Australia is of particular interest to gas consumers of the Pacific Basin. Positioned at number 14 in the proved gas reserve ranking—with potential to rise up the ranking as more discoveries secure offtake agreements—it is unlikely to join an international gas supply cartel or to be influenced by radical religious fundamentalist governments that could renege on long-term gas contracts should they secure power at some stage in the future.

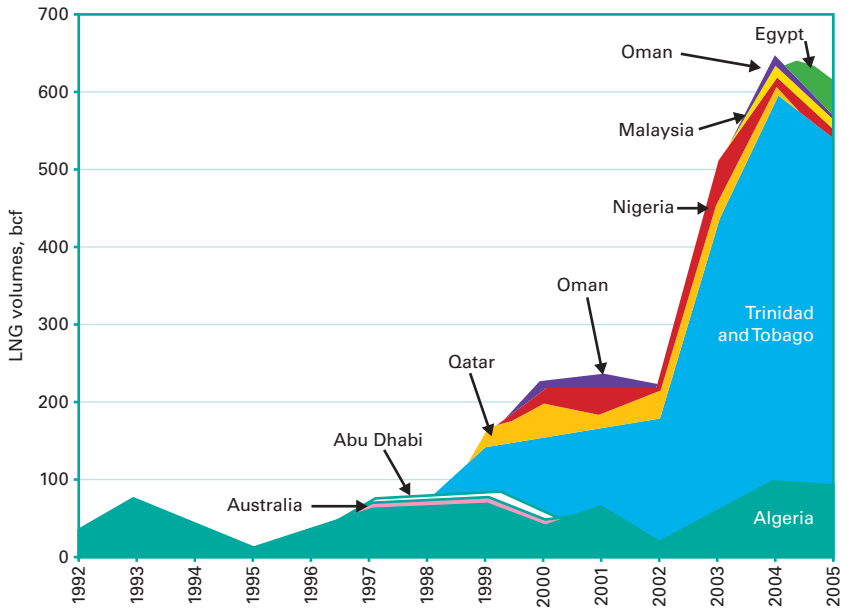
Long-term contracts with a large number of suppliers from different continents seems to be one means by which gas-consuming nations can protect themselves in part from the emergence of an international gas cartel in the future.

LNG offers a much better diversification lever for consumers than intercontinental pipelines. Not only can LNG provide gas from a number of sources, it also serves as competition to dominant pipeline suppliers such as Russia to Western Europe and can limit the supplier's ability to use unilateral threats of supply interruptions to secure excessive price increases to captive customers.

Building and developing a vast network of LNG supply sources is likely to hinder or inhibit the influence that an international gas cartel could exert.

LNG IMPORTS TO US BY COUNTRY OF ORIGIN

Fig. 4



Sources: Energy Information Agency, David Wood & Associates

New LNG supply chains such as those being built or considered by Angola and Equatorial Guinea in West Africa and by Norway and Peru all seem to be prudent steps along the diversification route.

Some nations have even had the foresight to legislate for a diverse gas supply base. Spain, for example, has required that its utilities limit supplies from individual nations to specified percentages and ensure that supplies from pipeline and LNG sources are well balanced.

It would be easy for Spain to take all of its gas by pipeline and LNG from nearby Algeria, but it would be prudent

to avoid relying completely on a single source, which would undoubtedly be a disadvantage should a gas cartel emerge.

Germany, on the other hand, is heavily reliant on Russian gas via pipelines crossing Eastern Europe. It does take some supply from Norway, the Netherlands, and Algeria, but it is most dependent on Russian supply.

The Russian-Ukrainian incidents of January 2006 that led to supply interruption to Western Europe during its peak winter demand period should be a warning to Germany and other Western European consumers of Russian gas to further diversify their supply.

The UK is establishing new gas supply chains by building new pipeline and LNG infrastructure. Pipeline gas supplies will come from Norway and continental Europe, including some gas originally derived from Russia.

LNG will come from Algeria, Qatar, Nigeria, Trinidad and Tobago, and other suppliers. It is tempting for the UK to sign up to large-scale supply deals with Russia once the trans-Baltic Nord Stream pipeline—now under construction—is completed. However, a competitive price for such gas only makes sense in terms of supply security if it is backed up with a large percentage of gas from other suppliers. The new LNG supply chains being developed should provide this leverage.

Diversification also means using a variety of primary energy mixes. If the major energy-consuming nations have learned anything from the evolution of the oil industry over the past 50 years, it is that it would be folly for the world to become as highly dependent on gas for power generation as we are on oil for transportation fuel. Hence it makes sense for nations to have a diversified, long-term energy supply strategy incorporating nuclear, coal, hydro, and renewables as well as gas.

This is in the interest of the consumer and the gas industry, as it will help to preempt attempts by gas-producing nations to hold consuming nations ransom over access to future supplies, and it is more likely to lead to more-stable and moderate gas prices.

Geopolitics

Regional geopolitics in Central Asia and the Middle East regions, where most gas reserves are located, have been dynamic and turbulent over the past few decades. Extreme optimism is required to believe that this situation will change over the next few decades. Hence, commercial, ideological, and ethnic conflicts and suspicion among Russia and its neighbors in the Caspian region, for example, or Iran and its neighboring Persian Gulf Emirates, including Qatar, may well undermine any potential power over consuming nations that organizing themselves into an international gas cartel could bring.

Russia has long exerted its power and influence in the Caspian states of the former Soviet Union, including control over their gas infrastructure and exports. Often this has worked to the detriment of those nations. For example, Russia prevented Turkmenistan from continuing gas exports to Europe following the breakup of the Soviet Union, and it continues to restrict Turkmenistan's ability to transit gas.

Those nations may show reluctance in further constraints on their export capabilities that a gas cartel led by Russia might impose. However, there are signs that Russia does see potential in developing closer ties with these nations and with Iran to coordinate their strategies in exporting gas by pipeline both east to China and beyond and west into Europe. If Russia and Iran were to forge such an alliance, an international cartel for gas would have a better chance of emerging.

Iran has yet to decide what it wants to do with its vast excess gas resources. It exports small quantities by pipeline to Turkey and imports some gas into northeast Iran from Turkmenistan, not a great export record for a county with more than 14% of the world's gas reserves.

Iran itself consumes substantial volumes of gas, both for reinjection and pressure support in its oil fields and to supply its own domestic energy needs. Indeed, there are powerful factions within Iran that argue against exporting gas at all, but urge retaining it for domestic consumption once the oil reserves are depleted.

The country has negotiated for many years with consortiums of international European and Asian companies—US companies are not allowed—for building both LNG and GTL plants. Despite Iran's entering many preliminary agreements and heads of agreement over the past decade to further develop its gas production leading to exports to India and China, final investment decisions by international companies to sanction the building of gas liquefaction and GTL plants in Iran continue to be delayed.

Because of geopolitical constraints, Pakistan, India, China, and perhaps Japan are the most likely customers of gas from Iran, either as LNG or by pipeline. The potential of long-distance pipeline exports to Europe through Turkey and Greece and to China through central Asia are themselves fraught with major geopolitical hurdles.

It is unlikely that the international financial community would debt-secure such pipelines from Iran, either west or east. Moreover, it would be an intrepid nation in Europe that would sign deals to offtake gas from such pipelines for a significant portion of their long-term gas supply.

Without the investment in such

PXP

Plains Exploration & Production Company

PXP, an independent oil & gas firm headquartered in Houston, Texas, is experiencing significant growth. This expansion has led to the creation of several new positions throughout the company.

Houston, Texas

Senior Drilling Engineer
Senior Landman
Senior Drafter
Planning Analyst
Reservoir Engineering Technician
Senior Reservoir Engineer
Geologist
Operations Coordinator (logging/geology)

Grand Junction, Colorado

Operations Manager
Land Manager
Senior Production/Facilities Engineer
Production Technician
Production Superintendent
Government Affairs Specialist
Senior EH&S Advisor

Challenge your potential at PXP. Our expertise starts with innovative people and we are trusted in the most demanding of environments. Qualified candidates may apply to jobs@pxp.com. PXP offers a very competitive market-based salary and excellent benefits package. Applicants must be authorized to work in the United States.

EOE **www.pxp.com** **M/F/D/V**

infrastructure and the commercial trust and rapport with many of the gas-consuming nations of the world, much Iranian gas seems destined to stay in the ground for the foreseeable future. This situation would dramatically reduce Iran's current influence in an international gas cartel should one materialize.

However, once major pipelines are in place to Europe and China from the Middle East and Central Asia, including East Siberia, and Russia has secured the substantial gas liquefaction capacity it currently is seeking on Sakhalin Island, in Shtokman field in the Barents Sea, and at St. Petersburg, with the aid of investment from OECD consumers, the impact of a gas cartel would be more influential on consuming markets.

Geopolitics, massive investment requirements, technical hurdles, consumer mistrust, and time to construct such epic gas supply systems all indicate that a gas cartel is not going to happen in the medium-term.

However, by investing in such projects OECD countries and companies should realize that they are sowing the seeds for a potentially formidable international gas cartel to emerge.

Geopolitical influence and threats to stability of worldwide gas markets do not just come from Central Asia and the Middle East.

The gas-producing nations of North Africa—Algeria, Libya, and Egypt—could certainly coordinate supply to the southern Mediterranean countries of Europe and perhaps cooperate with Russia in squeezing supply to Europe.

However, there is substantial competition among these North African suppliers to secure supply contracts and market share with European and North American consumers, and in the medium-term it is unlikely they would take actions that would risk loss of market share or alienation from their main gas markets. Algeria's more established infrastructure and supply contracts place it in a stronger position, with more market power than its neighbors. Algeria's recent moves to increase its fiscal take and control over exploration and production contracts testify to such power.

Venezuela, ninth in the proved gas reserves ranking, like Iran has been extremely slow to develop and exploit its reserves. The radical, anti-US, and expansionist policies of the Hugo Chavez government sought in 2006 to coordinate gas movement across South America by promoting an ambitious Venezuela-Argentina gas pipeline through Brazil and Bolivia.

Such coordination could consolidate Venezuelan control of most gas reserves in South America. Such a cartel would undoubtedly be willing to cooperate with Russia, Caspian, and Middle East gas producers to squeeze the international gas trade.

However, in order to do so, massive investment in the form of tens of billions of dollars to build long-distance pipelines and gas liquefaction facilities would be required to provide this potential South American cartel with the ability to export gas at all.

The OECD financial sector and international companies from those countries would be ill-advised to sanction investments in such infrastructure projects that risk ultimately being used to leverage control of international gas supply in a direction that would be disadvantageous to OECD gas-consuming nations.

Implications for the US

The US already imports large volumes of gas by pipeline from Canada and exports some pipeline gas to Canada and Mexico and LNG to Japan (Table 4). However in recent years it has become clear that its gas supply gap is widening rapidly as domestic production declines and gas demand rises. The position of gas imports and exports in the US in 2005 is illustrated in Fig. 2 together with the location of existing LNG receiving terminals and those under construction in 2006.

Most in the energy industry and in government recognize and accept that importing larger volumes in the form of LNG is essential for the US. Opposition, however, has come from two elements: local communities concerned about potential environmental and safety impacts of specific sites and from independent US gas producers that see imported LNG as threatening to flood the US market with "cheap" gas and erode their currently healthy profit margins.

The battle with the former has been largely overcome with new legislation in 2005 and government and state commitments in 2006. However, there has been substantial delay in commitment to many proposed LNG receiving facilities, particularly in California and the northeast seaboard. So much so that in 2006 the Energy Information Administration and others forecast that new US terminals are unlikely to contribute to much more than a third of LNG imports by 2020 (Fig. 3).

Most imports will come from expanding existing US terminals and from new terminals being built more rapidly in Canada and Mexico.

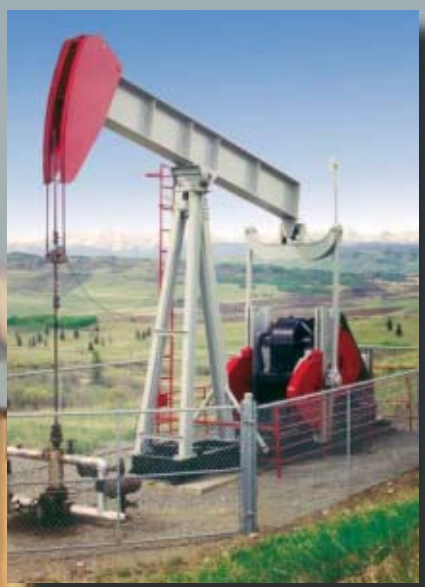
The position taken by the US independent gas producers is traditional protectionist rhetoric; they are emphasizing the risks of "getting hooked on gas imports" and the specter of "an OPEC for gas." Their aim is to raise the fear of a future US gas crisis caused by a cartel of international gas producers to which the US would remain impotent to respond. Such independent producers, however, would be among the first to benefit from the high prices

From the ground up, drilling to refining, TB Wood's has *your* part...

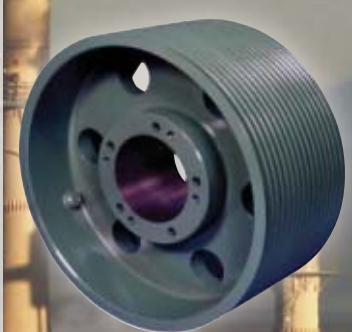
TB Wood's has supported the petroleum industry with quality products from the beginning. Over the years, methods and technologies have changed from the days of cable-and-tool drilling to today's rotary drills. TB Wood's flexible couplings and sheaves are found in every petroleum production process; including separation, conversion and chemical treatment.

We have the products you need:

- ✔ Sheaves, small to large and custom sizes up to 108" diameter.
- ✔ Form-Flex® couplings, including our 8-bolt axial split-spacer couplings that are ideal replacements for lubricated-gear and grid couplings.
- ✔ 100 years of engineering expertise, legendary field sales support all backed with available stock inventory sizes through 71".



Form-Flex® Couplings



V-Belt Sheaves

TB Wood's Incorporated
440 North Fifth Avenue
Chambersburg, PA 17202-1778
888-TBWOODS or 717-264-7161
www.tbwoods.com

A wholly owned subsidiary of
Altra Industrial Motion

Put TB Wood's 150 years of engineering experience to work for you!

that would accompany interruptions to international supplies.

The reality is that regardless of how much money is invested in US gas exploration, it will not generate enough gas, from either conventional or unconventional resources, to meet ongoing demand. Imports will continue to be necessary.

There are risks associated with becoming dependent on gas imports, but countries such as Japan, South Korea, and many European countries have been dependent on them for decades. These risks can be managed if consuming nations and companies follow some clear strategies—diversification of gas supplies, long-term contracts, integrated joint ventures, and diversification of energy mix—and collaborate with producing nations along the entire supply chain so that all parties benefit from the massive investments required.

At this stage the questions that should be asked in the US should be associated with "how best to" structure intercontinental gas-LNG imports, not whether gas should be imported at all.

The way forward

The logical way forward for the US would be supply diversification and the location of strategic infrastructure investments in countries that do not rank in the top 10 reserve holders—countries such as Equatorial Guinea, Angola, and Peru—and that pose the least threat of future alignment with any incipient international gas supply cartel that may emerge.

Embracing the international diversification of the LNG industry in collaboration with other major consuming nations in Europe and Asia seems to be the most positive step the US could make towards ensuring its future security of gas supply and helping to minimize the emergence of a cartel of international gas suppliers seeking to exert control and extract higher prices from the international gas trade.

Fig. 4 shows that the US must work harder to diversify its LNG supply. Trinidad and Tobago has dominated LNG imports to the US since 2002, benefiting from its closer location and lower marine transportation costs than other existing suppliers on the far side of the Atlantic and further afield in the Middle East and Asia.

The emergence of Egypt as an LNG exporter in 2005 plus the imminent new supplies from Equatorial Guinea, Norway, Nigeria, and Qatar, all expected on stream by 2008, should improve diversification and therefore security of supply. Based upon these discussions, a prudent national gas import strategy would avoid becoming reliant on a single nation supplier (Trinidad and Tobago or Qatar?) for more than about 20% of the nation's import demand.

The deregulated North American gas market has become accustomed to trading gas on a short-term basis. This doesn't make sense for the bulk of long-term base-load LNG imports. Long-term contracts with send-or-pay clauses and some supplier guarantees to both offtakers and financiers improve security of supply and minimize risk of supply interruptions and the possibility of suppliers' market manipulation.

Encouraging some supplier nations to take equity positions in LNG receiving terminals in the US also improves the chances of long-term relationships with a range of suppliers that can survive difficult market conditions without degenerating into contractual defaults.

Of course, the US is not in a position to dictate to its deregulated industry that gas imports should be limited from certain suppliers or expanded from others. Each LNG supply chain project is a stand-alone investment decision for the equity holders and their financiers.

However, it is the role of government to develop a long-term energy strategy and promote sustainable energy supplies. Therefore government has a role in promoting and providing incentives for prudent diversification, contractual security of supply, and coordinating among the supply chains to provide some strategic volume of LNG reserves to withstand supply interruption from whatever cause.

OECD gas-consuming nations should have little to fear from the market power and control that an international gas supply cartel could exert or from manipulated supply shortages if they execute the following long-term gas import policies:

1. Diversification of gas supply.
2. Diversification of primary energy mix.
3. Long-term supply contracts with volume guarantees.
4. Limited investment in gas infrastructure projects that enhance the market power of potential international gas cartel coordinators such as Russia, Algeria, Iran, and Venezuela.
5. Disregard for domestic lobby groups with vested interests to keep gas imports in tight supply, enabling them to exploit captured consumers with high prices.

Also, should a gas cartel materialize in the future, it is unlikely to ever influence worldwide trade in gas to an extent comparable with the power that OPEC continues to enjoy.

Nevertheless, prudence in contracting and sanctioning of international supply chain investments, coupled with vigilance and suspicion of the strategies and motives of those nations seeking to establish and exert coordinated global control over worldwide gas markets, is required to avoid the emergence of an OPEC for gas at some stage in the future. ✦

The author

David Wood (woodda@compuserve.com) is an international energy consultant specializing in the integration of technical, economic, risk, and strategic information to aid portfolio evaluation and management decisions. He holds a PhD from Imperial College, London. Key parts of his work are research and training concerning a wide range of energy related topics, including project contracts, economics, gas-LNG-GTL, and portfolio and risk analysis. Wood is based in Lincoln, UK, (www.dwasolutions.com) but operates worldwide.

Price-gouging bill heads for US House amid protests

Nick Snow
Washington Correspondent

Rep. Bart Stupak (D-Mich.) convened a US House subcommittee hearing May 22 to examine rising gasoline prices amid record oil company profits. Republicans used most of their opening statements instead to protest the scheduled May 23 arrival on the floor of Stupak's gasoline price-gouging bill.

The bill, HR 1252, would empower the US Federal Trade Commission to investigate gasoline or other petroleum product price manipulation allegations at the wholesale and retail level. It would ban sales at prices that are "unconscionably excessive" or take "unfair advantage" of consumers.

The bill is scheduled to arrive on the floor under a rules suspension, which requires a two-thirds majority to pass but prevents the bill's being amended. Republicans protested that it was moving forward without a full hearing and markup by the Energy and Commerce Committee. Democrats responded that Republicans used a similar tactic in 2006, when they were in the majority, to bring Rep. Heather Wilson's (R-NM) competing price-gouging bill to the floor for a vote.

The House approved Wilson's bill last year, but the US Senate did not act on it. However, this year the Senate Commerce Committee added Maria Cantwell's (D-Wash.) price-gouging bill as an amendment to a fuel economy bill it passed on May 8.

"The American public is paying record high gas prices while Big Oil companies are reaping record profits. Across our nation, people are struggling to fill their gas tanks, and their frustration with gas prices is boiling over," said Stupak as he began the Energy and Commerce Committee's Oversight and Investigations Subcommittee's May 22 hearing.

When Rep. Marsha Blackburn (R-Tenn.) warned against demonizing retailers, saying 95% of convenience stores and gas stations across the country are independently owned, Stupak countered that his bill gives priority to prosecuting businesses with more than $50 million/year in revenues.

Vague language

But the subcommittee's chief minority member Ed Whitfield (R-Ky.) said the bill's language was too vague. "The FTC has notified Congress that if it passes a price-gouging bill, the language in it must be clear and easy to enforce. I favor Rep. Wilson's bill [which Wilson reintroduced early in 2007] because it leaves the definition to the FTC."

Joe Barton (R-Tex.), the full committee's chief minority member, opposed the rules suspension and how witnesses for the hearing were obtained. "We're not going to hear from the people who explore for oil, who refine oil, who distribute oil products, and who sell products at the retail level. They told the minority staff that they'd be willing to testify, but not one of them is here as a witness," he said.

Stupak responded that he invited ExxonMobil Corp., Chevron Corp., Shell Oil Co., and Valero Energy Corp. to testify, but they declined. So did the American Petroleum Institute and the National Petrochemical & Refiners Association, he said. The chairman of President George W. Bush's Council of Economic Advisors expressed interest in appearing but could not fit it into his schedule, the subcommittee chairman said.

Noting that Barton last year sent Wilson's bill to the floor under a rules suspension, John D. Dingell (D-Mich.), the full committee's chairman, said, "I'm doing the same with Rep. Stupak's bill. I look forward to replicating Mr. Barton's effective leadership in other ways," he said.

Growing opposition

But groups outside the House and Senate have become vocal in their

opposition to any legislation aimed at stopping alleged manipulation of gasoline and other oil product prices because it could lead to mandatory controls and allocations.

The National Association of Manufacturers ran a full-page advertisement May 22 in the Washington Post expressing its disapproval, while the National Association of Convenience Stores had one in Congress Daily. NPRA and the Competitive Enterprise Institute each distributed information to reporters covering the hearing.

Hours earlier the Alliance for Energy & Economic Growth, a coalition of more than 1,200 energy producers and consumers, raised its concerns over legislation aimed at alleged gasoline price-gouging and other bills in the 110th Congress that would roll back provisions in the 2005 Energy Policy Act, authorize prosecutions of foreign oil-producing countries for violating US antitrust laws, and cancel alternative energy research and development.

Following the AEEG briefing API Pres. Red Cavaney said: "People are every bit as upset this year as they were in 2006. They see there have been no hurricanes, but there have been refinery breakdowns and significantly lower product imports. Add to that what's going on in Nigeria, what could happen in Venezuela, and what's uncertain in Iran and Iraq, and you have a very unsettled situation. But I hope people will understand that gasoline price-gouging legislation could lead to controls, which were the most horrific experience we had to undergo in the last 25 years."

Jay Inslee (D-Wash.) said Congress should give FTC the authority it needs to act in the consumer's interest, and it should increase consumer choices of fuels such as electricity, cellulosic ethanol, or biodiesel.

'A bottleneck'

Rep. Charlie Melancon (D-La.) said continued heavy reliance on fossil fuels poses environmental impact questions, but it will be necessary in the short term. "We have a bottleneck in the process. We can't pump oil out of the ground and refine it fast enough to meet the growing demand," he said.

Rep. Jim Murphy (R-Pa.) said: "One thing we should not do is adopt policies that establish artificial controls. We did that during the Nixon and Carter administrations, and the results were shortages and long lines," he said. "When we refuse to commit support to building more refineries, we increase costs by buying products that are refined overseas. It's the same with crude oil and natural gas. When are we going to recognize that we have supplies at home and start producing them?"

Witnesses included FTC commissioner William E. Kovacic, US Energy Information Administration chief Guy F. Caruso, Michigan Dept. of Environmental Quality deputy director Stanley F. Pruss, Thomas J. McCool of the US Government Accountability Office, W. David Montgomery of CRA International, Geoff Sundstrom of the American Automobile Association, and Tyler Slocum of Public Citizen. ✦

Venezuela nationalizes oil rigs; deepens Chinese ties

Peter Howard Wertheim
OGJ Correspondent

Venezuela's Minister of Energy and Petroleum Rafael Ramirez announced that the country would be nationalizing oil rigs, currently in private hands.

"Venezuelan state oil company Petroleos de Venezuela SA (PDVSA) owns 18 rigs that in the past were handed over to multinationals. These firms demand billions for using this equipment. Under these circumstances, we have decided to nationalize this equipment," Ramirez told newspaper El Universal. Ramirez also serves as PDVSA's chief executive officer.

Venezuela is importing oil rigs from China and is subsequently organizing a joint venture to manufacture oil rigs in Venezuela, Ramirez added.

"The first oil rig manufactured in China to be owned by PDVSA will arrive in Venezuela next November. We have plans to purchase 13 rigs, each of which will arrive in the country on a monthly basis," Ramirez told official news agency ABN.

"Parallel to this agreement, in Venezuela we are installing an oil rig assembly plant, and in a second phase we have a goal to manufacture oil rigs in the country."

Foreign rig operators in Venezuela include Schlumberger Ltd., Pride International, and Baker Hughes Inc. According to Baker Hughes data, Venezuela has 80 active drilling rigs in the country.

Venezuelan, Chinese ties

Venezuela and China are deepening their economic and political ties. Recently Venezuela President Hugo Chavez and Chinese Communist Party Politburo members signed six cooperation agreements, mostly in the energy sector, and one to form a $6 billion binational investment fund.

The energy accords focus on JVs to explore for oil and gas deposits in both countries, and to extract, transport, store, and refine these resources. These measures will help advance Venezuela's goal of diversifying its trading relations away from the US and reducing its dependence on that market for its oil exports.

China will provide an expanded supply of oil and gain a larger foothold in the Latin American region.

The deals include:

- A JV of PDVSA and China National Petroleum Corp. for oil production in the Campo Junin field in Venezuela's heavy-oil Orinoco basin.

• A JV to build tankers to transport the crude, with a goal of eventually having a full fleet of tankers.

• Accords to jointly service and maintain oil wells and to increase the daily supply of Venezuelan oil to China.

Separately, Ramirez said, "We are planning to build 14 new refineries in other countries, especially in Latin America. Most of them were already included in previous energy agreements. These facilities will guarantee excellent volumes of oil from the Orinoco belt for several countries in the continent that do not have this resource." ✦

Kerr-McGee, EPA settle Rockies air pollution allegations

Nick Snow
Washington Correspondent

Kerr-McGee Corp. agreed to spend $18 million on pollution controls and pay a $200,000 fine in a comprehensive settlement covering operations in Colorado and Utah, the US Environmental Protection Agency said on May 17.

EPA said the company, which Anadarko Petroleum Corp. bought in 2006, also agreed to spend $250,000 on environmental projects in the two areas where alleged violations of federal air pollution regulations occurred.

The settlement addresses alleged violations at natural gas compressor stations on the Uinta and Ouray Indian Reservation near Vernal, Utah, and in the Denver Julesberg basin of Colorado. The control measures and operational improvement are expected to reduce air pollution emissions by more than 3,000 tons/year in Utah and more than 2,500 tons/year in Colorado, EPA said.

EPA said Kerr-McGee disclosed a number of the violations itself and worked with state and federal regulators to resolve them.

Colorado independently initiated enforcement actions against Kerr-McGee in which it alleged violations at five gas compressor stations in Weld County during the last half of 2005. The state and EPA agreed to begin joint discussions with the oil and gas producer concerning those allegations and others in Utah in early 2006, the federal regulator said.

Under the settlement, Kerr-McGee will spend $100,000 to reduce dust emissions from roads that service oil and gas facilities in Utah, and $150,000 to identify and retire vehicles with higher emissions than

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Japan's energy explorations

If you ever thought exploration and production meant huge outlays of cash for oil and gas projects in far-off locales, think again. Now, with a little help from the inventive Japanese, the next energy source is as close as your nearest garbage can.

Consider the work of Eicoh Co., which has commercialized a system called Yukaki that produces reclaimed oil from waste plastic. To produce the oil, Yukaki—to be familiar—first pulverizes and melts such waste plastics as polyethylene.

Then Yukaki heats the plastic to some 400° C. in a thermal decomposition tank to vaporize it, whereupon the collected gas is cooled and the oil taken from it. We are told the extracted oil is the equivalent to fuel oil, which can be used to fuel generators and other heavy machinery.

Ingenious? Well, consider another idea coming from Japan to reduce waste and enhance the performance of power stations, while increasing the production of a form of natural gas.

Shellfish interests

This idea comes from researchers at the University of Tokyo and the National Institute of Advanced Industrial Science and Technology who have worked with Kajima Corp. to develop a way to process shellfish that encrust water intake openings at power stations and factories that use seawater for cooling.

The shellfish tend to hamper water flow and need to be periodically removed, but disposal sites are in short supply. Worse, the shellfish cannot be used for food and—if left to sit—develop foul odors.

Under the new method of removing and processing the shellfish, both the shells and the meat are processed at the same time to recover usable substances from both. The shellfish are first put in a solution of acetic acid, which dissolves the shells, allowing the meat to be removed.

The meat is allowed to ferment in order to generate methane, while the solution of dissolved shells is processed to recover calcium carbonate, which can be used for cement, paper, and other products. Even the acetic acid can be recovered and reused.

Algae power

Then, again, Tokyo Gas has begun marketing a new power-generation system that employs fuel gas derived from the algae that accumulate in harbors.

Collected algae are now simply incinerated, but disposing of 1 ton involves energy consumption equivalent to 30 cu m of city gas due to the high water content.

The new system flips this around and actually creates energy from the processing of the algae. The collected algae are pulverized and then fermented in tanks to generate methane. The methane is then mixed with city gas to maintain a stable heat value when the gas is burned to generate electricity.

Thinking of your next elephant? Forget it. We have an idea that involves sushi... ✦

newer models in Colorado.

The company also agreed to:

- Install low-emission dehydrators at its new Uinta basin facilities.
- Install emissions controls on storage tanks at the Cottonwood and Ouray facilities in Utah and the Brighton facility in Colorado.
- Install emission controls on 25 compressor engines in the Uinta basin and 11 compressor engines in the Denver Julesberg basin.
- Retrofit high-bleed pneumatic controllers with low-bleed models at facilities in the two production areas.
- Install liquid bed sulfur removal where necessary in the Uinta basin to remove hydrogen sulfide.
- Spend $300,000 to develop an air-monitoring program in the Uinta basin.
- Implement a Uinta basin pilot project which gathers multiphase fluids from multiple producing gas well sites for collection, separation, and metering at a central facility.
- Conduct a study to increase gas recovery and reduce air emissions at five facilities each in the two basins. ✦

Sudan's oil production, refining capacity climb

Sudan is climbing on the list of African oil producing countries and is seeing its refining capacity expand as well.

The country's oil production averaged 414,000 b/d in 2006, up from 363,000 b/d in 2005, said the US Energy Information Administration, and China is in the forefront of the country's oil developments.

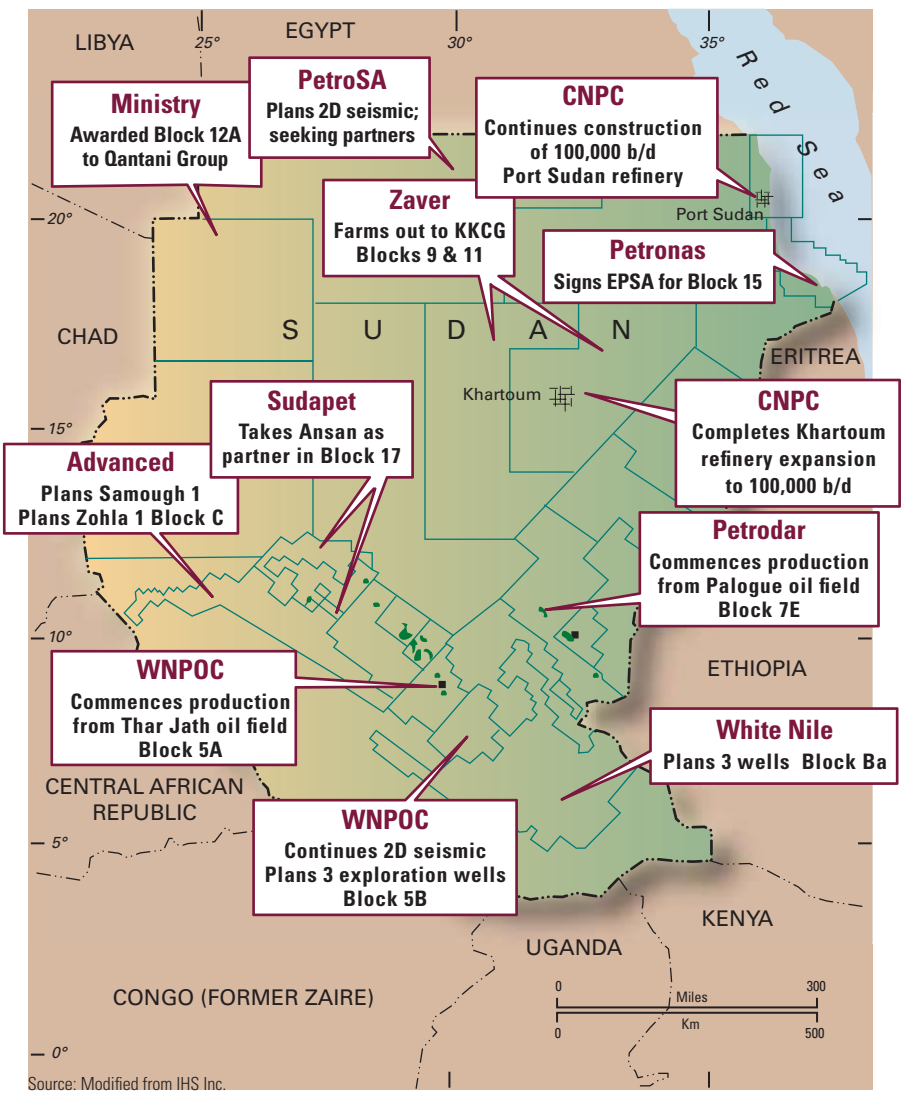
Capacity of the two main pipelines from interior oil fields to Port Sudan totals 450,000 b/d, and together these are expandable to 950,000 b/d. Minister of State for Mines and Energy Angelina Tany said Sudan plans to be producing 1 million b/d of oil by the end of 2008.

Sudan consumed 94,000 b/d of oil in 2006 and exported 320,000 b/d, most of it to Asian countries, EIA said.

"Factional fighting in the south and rebel attacks on oil infrastructure have kept oil production and exploration from reaching full potential to date," EIA said.

An expansion of the Khartoum refinery to 100,000 b/d from 50,000 b/d was completed in mid-2006, and a 100,000 b/d refinery is under construction at Port Sudan for completion

SUDAN OIL AND GAS ACTIVITY



Source: Modified from IHS Inc.

in 2009.

Exports of Sudan crude in 2006 went to Japan, China, South Korea, Indonesia, and India, EIA said.

Muglad basin

Sources of oil production in Sudan have spread out to multiple blocks since the first oil shipment left Port Sudan on the Red Sea in September 1999.

Greater Nile Petroleum Operating Co., as successor to Talisman Energy Inc., Arakis Petroleum Corp., and Chevron Corp., still operates Sudan's largest share of production, from Heglig, Unity, and surrounding fields on blocks 1, 2, and 4 in the Muglad basin (OGJ, May 17, 1982, p. 36).

These fields produced 260,000 b/d of Nile blend crude in January 2007, EIA said. Nile blend is 33° gravity with 0.045% sulfur. Arakis initiated development in 1996.

Capacity of GNPOC's 994-mile pipeline to Port Sudan is 300,000 b/d and is expandable to 450,000 b/d. GNPOC is a joint venture of China National Petroleum Co. 40%, Petronas of Malaysia 30%, Oil & Natural Gas Corp. of India 25%, and Sudan National Petroleum Corp. (Sudapet) 5%.

Meanwhile, another group known as White Nile Petroleum Operating Co. started production from Block 5a in mid-2006. Production from Thar Jath field remains at 38,000 b/d as of March 2007, EIA said. The block also contains Mala field.

Thar Jath oil flows through a 110-mile pipeline to Unity field, where it is shipped to Port Sudan on the GNPOC pipeline.

Elsewhere, White Nile Ltd., London, spudded an exploration well Apr. 19 on 67,000 sq km Block Ba in the Jonglei subbasin of the southeastern Muglad basin on acreage that is also claimed by Total SA of France (OGJ Online, Apr. 20, 2007).

Melut basin

The Petrodar group of companies produced 165,000 b/d of oil in January 2007 from Palogue field on blocks 3 and 7 in the Melut basin and could build this to 200,000 b/d by late 2007, EIA said. Estimated recoverable oil in Palogue and Adar-Yale fields is 460 million bbl.

CNPC started up the Petrodar pipeline from blocks 3 and 7 to Port Sudan in late 2005. Capacity is expandable to 500,000 b/d. The project also includes a 300,000 b/d central processing facility at Al-Jabalayan and production facilities at Palogue.

Palogue's Dar blend crude is understood to have a high acid content that the Port Sudan refinery is being designed to handle.

Members of Petrodar are CNPC 41%, Petronas 40%, Sudapet 8%, Gulf Petroleum 6%, and Al-Thani Corp. 5%.

Other areas

CNPC is producing oil since November 2004 from Fula field on Block 6 in troubled Darfur Province 400 miles southwest of Khartoum.

The company is producing 40,000 b/d, EIA said, and intends to raise this to 80,000 b/d. It has built a pipeline that transports the Fula crude to the Khartoum refinery.

Exploration is at a much earlier stage in other parts of the country, where various companies are acquiring blocks, planning seismic surveys, and seeking partners (see map).

"It is estimated that vast potential reserves are held in northwest Sudan, the Blue Nile basin, and the Red Sea area in eastern Sudan," EIA said. ✦

Ridgeway to delineate CO_2 field, eyes Permian EOR

A Houston independent has decided to commence its own Permian basin carbon dioxide pilot floods hoping to jump-start demand for CO_2 from a world-class helium and CO_2 resource in New Mexico and Arizona.

A reoriented Ridgeway Petroleum Corp. has the task of delineating the nearly 400-sq-mile St. John CO_2 field that the ex-Calgary company's founder discovered in 1994. A scant 26 wells have been drilled in that accumulation, the extent of which is defined only by geologic work.

Ridgeway's founder, Walter Ruck, who passed away in 2005, thought the best market for the St. John CO_2 was for enhanced oil recovery in light oil fields of California's Los Angeles and Ventura basins.

Ruck's successor, Barry Lasker, has redirected marketing efforts toward the Permian basin, already supplied by three large CO_2 pipeline systems. Lasker, president and chief executive officer, also plans to truck CO_2 to Ridgeway's own oil production pilot projects until industry support materializes for construction of a pipeline.

Permian EOR

The reserves that supply two of the three large pipelines that ship CO_2 to the Permian basin from Colorado and northeastern New Mexico are declining, Lasker noted.

Those pipelines were built in the 1980s from Sheep Mountain field west of Trinidad, Colo., and Bravo Dome field near Bueyeros, NM.

The third system originates at McElmo Dome field southwest of Cortez, Colo. Its operator, Kinder Morgan, is considering an expansion, but producers have already spoken for all of the additional supply.

With oil prices near record highs, demand for CO_2 for EOR in the Permian basin is at an all-time high. Lasker expects to conduct an open season later in 2007 to gauge oil producers' needs for CO_2 from St. John field. He estimates permitting and construction of a 250-500 MMcfd, 300-mile pipeline would

take 2 years.

Meanwhile, Ridgeway in February 2007 completed the purchase of 15,000 acres in a 19,000-acre mature Permian basin oil field. It cited an independent estimate that the field, which has produced 14% of the original 180 million bbl of oil in place, could recover a further 34 million bbl with state-of-the-art CO_2 injection.

Lasker said Ridgeway hopes to begin trucking and injection CO_2 later this year and continue for at least several months. Last month Ridgeway signed a binding agreement to purchase another oil field adjacent to its first acquisition.

Ridgeway did not identify the properties because it is pursuing other acquisitions in the area but said they produce oil from a formation that has responded well to CO_2 injection elsewhere in the Permian basin.

Field and pipeline

The main line to the Permian basin would be expandable to 500 MMcfd.

An extensive gathering system would be required, and bottomhole pressures of 400-500 psi would entail compressors hooked up to a power grid link in eastern Arizona.

Wells would require fiberglass and stainless steel tubulars and nickel-coated packers.

St. John field, 40% in Catron County, NM, and 60% in Apache County, Ariz., is at 7,000 ft above sea level. Ridgeway controls 200,000 acres in the area.

Consulting engineers estimate the St. John resource at 15 tcf in place, of which 5 tcf may be recoverable. The gas also contains 30 bcf of recoverable helium.

Power plants in the Permian basin produce large volumes of CO_2, but Lasker said the pipeline will be competitive with them at $1.50-1.80/Mcf for CO_2 because such plants require installation of processing equipment at $30/ton to separate CO_2 from the raw stack gas.

Drilling program

Ridgeway had three rigs running in late April on a 12-well program in New Mexico designed to hold expiring leases, evaluate air drilling and various completion methods, test zones individually, and learn well deliverabilities and decline rates.

One of the wells found CO_2 and helium for the first time in fractured Precambrian basement at TD 2,666 ft, adding to that previously encountered in the Permian Granite Wash, Amos Wash, and Fort Apache formations at 1,800-3,000 ft.

The same well was drilled through the Granite Wash to total depth without encountering any water returns and appears to have extended the lowest known gas by 55 ft to 4,250 ft above sea level.

Another air-drilled well stabilized at 2.5 MMcfd, the field's highest natural flow rate, from Amos Wash open hole at 1,740-1,907 ft.

None of the 26 wells has encountered oil or natural gas.

Ridgeway hopes to drill another 10 wells later in the year, 1 or 2 of which could be horizontal.

Over the next 2 years, the company expects to drill up to 200 wells at St. Johns with initial production of 250 MMcfd to commence late in 2009. ✦

Noble Energy's Israel natural gas business builds

Gas production from Mari-B field in the Mediterranean Sea off southern Israel averaged 103 MMcfd in the quarter ended Mar. 31 net to the 47% interest of project operator Noble Energy Inc., Houston, the company said in early May.

Net output averaged 93 MMcfd in 2006, 40% higher than in 2005 and almost double that of start-up year 2004. Pipeline facilities under construction will enable delivery of gas by late 2007-early 2008 to two more power plants, a desalination plant, and a paper mill.

Gross gas production capacity climbed to 600 MMcfd from six wells in March with recompletion of the Mari-B No. 7 development well, boosting the well's deliverability to 180-200 MMcfd. Holding the other interests in Mari-B are Avner Oil Exploration LP, Delek Drilling LP, and Delek Investments and Properties Ltd.

Meanwhile, Noble Energy secured a rig to drill the Tamar exploration well in late 2007 or early 2008. It is operator with 33% interest.

The location is on the Matan license 50 miles off northern Israel and 30 miles southeast of the nearest block in the first Cyprus licensing round (OGJ Online, Jan. 26, 2007). ✦

India

Reliance Industries Ltd., Mumbai, gauged a gas-condensate discovery on Block GS-OSN-2000/1 in the Gujarat-Saurashtra basin off India's west coast.

The B1 well, drilled to TD 2,282 m in 78 m of water, found hydrocarbons in a Mid-Miocene carbonate reservoir. On a drillstem test it flowed 18.6 MMcfd of gas and 415 b/d of condensate on a 5/64-in. choke with 1,346 psi FTP.

The well, designated Dhirubhai-33, is the company's first west coast discovery in a carbonate reservoir. Block interests are Reliance 90% and Hardy Oil & Gas PLC 10%.

Kirgizstan

Drilling could begin in July 2007 on an 11-well program in the Mailisu and Charvak areas southwest of Bishkek along the border with Uzbekistan, said Caspian Oil & Gas Ltd., Balcatta, Western Australia.

The company purchased a $3.5 million rig capable of drilling to 2,500 m from a Chinese manufacturer.

The company plans six wells on the

Mailisu III license 70% owned with the state oil company Kyrgyzneftegaz as a partner and the rest on shallow prospects on the Ashvaz, East Mailisu, and Charvak licenses in a joint venture with Santos Ltd.

The Mailisu III wells are to delineate an extension of the state company's producing oil field, which has yielded 700,000 bbl to date. Initial targets are Paleogene limestone beds V and VII at 600-1,000 m.

Philippines

Nido Petroleum Ltd., Perth, and Yilgarn Petroleum Philippines Pty. Ltd. plan to focus on two areas of 537,600-ha SC 54 off northwest Palawan Island and south of Malampaya field.

One focus area covers the Coron North prospect and the Pagasa turbidite play, including the Princesa lead, on the western part of the block. The companies plan to shoot 180 sq km of 3D seismic there in the third quarter of 2007.

Other 3D surveys identified 24 pinnacle reefs similar to Nido oil field in less than 120 m of water on the eastern part of the block.

Turkey

Otto Energy Ltd., Sydney, and Incremental Petroleum Pty. Ltd., Perth, launched 125 line-km of 2D seismic surveys and a surface geochem survey on the Edirne license in the onshore Thrace basin.

The surveys are aimed at the Urun prospect and the periphery of the license (OGJ Online, Mar. 13, 2007).

The companies are also tendering for a 149-sq-km 3D seismic survey due to start in the next few months over the permit's most prospective area, including three gas discoveries made in 2005-06.

Prince Edward Island

Corridor Resources Inc., Halifax, NS, has an option to fund and drill an exploratory well to 2,800 m on 176,000-acre EL 02-03 on eastern Prince Edward Island under a farmout agreement with PetroWorth Resources Inc., Calgary.

The companies will exchange proprietary seismic data on PetroWorth's EL 02-03 license on PEI and Corridor's Rosevale and Elgin properties in New Brunswick. Corridor also has the option to take a farmout on EL 02-03.

Under the farmout, Corridor must decide by Aug. 12 whether to drill the well and spud by Feb. 1, 2008. If it drills, Corridor will have the option to drill two more exploratory wells by Oct. 1, 2008, to be funded 50-50. Corridor would earn a 50% working interest in the license and wells by drilling three wells.

The agreement also gives Corridor the option to fund, drill, and complete two wells on four other PetroWorth PEI licences totaling 250,000 acres to earn a 50% working interest in those licenses.

Quebec

Petrolympia Inc., private Quebec independent, was awarded an oil and gas exploration permit on 16,399 ha in the Basses-Terres region of the St. Lawrence Lowlands in Quebec.

Petrolympia, with 100% interest, plans to shoot seismic surveys and drill three exploratory wells in the lowlands, where it holds 73,021 ha on several properties. The company's portfolio includes 113,906 ha of permits in the Appalachian basin of Quebec that include 40,885 ha of permits between Rimouski and Matane southwest of Lake Matapedia and south of Valleyfield 30 km southwest of Montreal.

Oklahoma

Bankers Petroleum Ltd., Calgary, is exploring the Devonian Woodford shale in southern and southeastern Oklahoma.

The company is drilling Greenway 35-1H, a horizontal offset to the Nickel Hill 1-26 discovery well in Carter County at which the initial potential was 470 Mcfd of gas. A second horizontal Woodford shale well is to be drilled 10 miles away in Johnston County.

Bankers and a partner are acquiring 115 sq miles of 3D seismic surveys in Carter and Johnston counties.

Bankers also plans to drill a horizontal Woodford shale test by the end of the third quarter in Hughes County. Its Lake Holdenville 35-1 well was disappointing, but a frac may not have effectively stimulated the shale, the company said. A 2.5-mile offset, however, had an initial production rate of 330 Mcfd after stimulation.

Utah

Gasco Energy Inc., Denver, set production casing to TD 16,763 ft at a deep exploratory well in Uinta County.

Tests are to begin in June. Preliminary log analysis indicated gas pay in the targeted sands, siltstones, and shales with fracture potential indications in the Cretaceous Dakota and Mancos formations, the company said. The Federal 14-31 well, in 31-9s-19e, also found the expected pay in Eocene Wasatch, Cretaceous Upper and Lower Mesaverde, and Cretaceous Blackhawk formations. Gasco's interest in the Uinta basin well is 100%. It is the company's first well to test deeper formations on the Riverbend Project.

West Virginia

Republic Energy Inc., Dallas, and Trans Energy Inc., St. Mary's W.Va., formed a joint venture to carry out seismic surveying, drilling, coring, completion, and production operations in Wetzel County.

The JV will target gas in Marcellus, Rhinestreet, and other Devonian shales. The first well is to spud in July.

Recent development by Trans Energy and other operators in the area has shown attractive shale thickness, gas in place, and other conditions for high levels of hydrocarbon recovery, Trans Energy said. Republic Energy is a private Dallas independent active in the Barnett shale.

DRILLING MARKET FOCUS

Companies report positive first-quarter 2007 results

Nina M. Rach
Drilling Editor

Drillers and drilling service companies continue to build new land and offshore rigs, although yards are full and there is some softening in the North American land rig market. This picture emerged from analysts' review of companies following conferences and quarterly reports.

Operators and service companies spoke at the Independent Petroleum Association of America's (IPAA) 11th annual Oil & Gas Investment Symposia (OGIS) in New York in April.

Parker Drilling Co. Chairman, President, and CEO Robert Parker Jr. said the company's revenue has been evenly split between domestic and international and that US revenue increased 49% in 2006 over the previous year. He expects international business to increase in 2007. The company has 34 drilling rigs and 19 barge rigs operating in 15 countries and also operates 8 other rigs under operation and maintenance contracts.

Parker said the company had $195 million in capital expenses in 2006, including $72 million to build four, 2,000-hp land rigs; $29 million to build the 77B ultradeep drill barge; $8 million to convert workover barge 12B to a deep drilling barge; and $50 million to expand Quail Tools to six locations in the US.

Dave Mannon, Parker Drilling senior vice-president and chief operating officer, said the company is benefiting from increased margins on contract turnovers for six international rigs, which are all moving to 3-year contracts in southern Mexico, Libya, and Kazakhstan. Parker also has rigs in Colombia, Algeria, Kuwait, Saudi Arabia, Bangladesh, Turkmenistan, Sakhalin, Papua New Guinea, Indonesia, and New Zealand.

Parker Drilling is also benefiting from the 17 barges it operates in the US. Mannon said that barge-rig day rates have risen dramatically in the Gulf of Mexico in the last 4 years. In 2003, intermediate-depth barges leased at about $13,000/day, and the current average is $38,600/day (197% increase). Deeper drilling barges that leased at $17,700/day in 2003 are now averaging $52,900/day, up 199%.

Mannon discussed the company's 2006-07 front end engineering and design (FEED) contract to design a unique rig for BP Alaska's Liberty project in which BP authorized Parker to procure long lead items. Mannon told OGJ that BP will sanction the full scale project in 2008, which will provide Parker the opportunity to begin detailed design and construction.

Parker and Mannon reiterated reports that the company set an extended-reach drilling record from the Yastreb rig in Sakhalin I, reaching 37,016 ft laterally in the Z-11 well (OGJ, May 7, 2007, p. 9).

Offshore drillers

There are 126 offshore rigs under construction, including 14 drillships, 38 semisubmersibles, 67 jack ups, 3 drilling tenders, 3 inland barges, and 1 platform rig (Table 1).

All of the drillships are being built in South Korea, with the exception of MPF Corp. Ltd., which is building one in Spain.

Transocean Inc., Stena Drilling (a wholly owned subsidiary of Stena AB), and Pacific Drilling Ltd. are building three drillships each; Petrobras-Mitsui (PNBV) and SeaDrill Ltd. are building two each.

Among the semisubs, 15 are under construction in Singapore, 8 in China, 7 in South Korea, 4 in UAE, 2 in Russia, and 1 each in Norway and Iran (Caspian).

Most of the jack ups (40) are being built in Southeast Asia. Another 11 are in the US Gulf of Mexico; 7 in the Persian Gulf, 5 in China, 3 in India, and 1 in Russia.

SeaDrill is building two drilling ten-

OFFSHORE DRILLING RIGS UNDER CONSTRUCTION, MAY 2007

Table 1

	Far East[1]	South-east Asia[2]	India	Africa, Middle East	Europe, Russia	US	Total
Drillships	13	–	–	–	1	–	14
Semisubmersibles	15	15	–	5	3	–	38
Jack ups	5	40	3	7	1	11	67
Drilling tenders	–	2	–	1	–	–	3
Inland barges	–	–	–	–	–	3	3
Platform rigs	–	–	–	–	–	1	1
Total	**33**	**57**	**3**	**13**	**5**	**15**	**126**

[1]South Korea, China. [2]Singapore, Malaysia.

ders in Malaysia (one for Varia Perdana), and Saipem is building its TAD-1 drilling tender in the Congo.

Inland Bay Energy Services is building three inland barges for the Gulf of Mexico.

Nabors Offshore is building one platform rig (Super Sundowner XX).

Several drillers issued first-quarter 2007 reports in April.

ENSCO International operates 46 offshore rigs worldwide. The company's strategy is to continue to expand into the international deepwater market. This accounted for 57% of gross income in 2006 and analysts project 75% of gross income in 2007.

Lehman Bros. Sr. Vice-Pres. Angeline Sedita said ENSCO may move two or three additional rigs out of the Gulf of Mexico this year. The company has three high-specification deepwater rigs under construction and Sedita thinks it is likely to continue to expand its deepwater fleet through additional new construction.

Transocean updated its fleet contract status on May 1.

SCORE

GlobalSantaFe Corp. reported that the worldwide SCORE, or Summary of Current Offshore Rig Economics, for March 2007 increased 4% to 138.2 from the previous month's 132.9.

The SCORE for the Gulf of Mexico was 110.5 and showed the greatest regional increase, 7.7%, over the previous month, but only 3.5% over the previous year. The SCORE for West Africa was 142.3; it increased 5.4% and 33.3% over the previous month and year, respectively.

The Southeast Asia SCORE increased 2.1% over the last month to 127, up 55.5% over the past year; this region has shown the most dramatic regional increase in profitability. The North Sea SCORE was 152.4 in March; it increased only 0.3% from the prior month, and 16.5% over the prior year.

Semisubmersibles have been increasing in profitability over jack up rigs since mid-2006. The semisub SCORE was 156.4 in March, up 7.1% and 32.8% from the prior month and prior year, respectively. The jack up SCORE was 126.3 in March, up 0.8% for the month and 9.5% over the year.

GlobalSantaFe's SCORE compares the profitability of current mobile offshore drilling-rig day rates to the profitability at the 1980-81 peak of the offshore drilling cycle. In 1980-81, when SCORE averaged 100%, new contract day rates equaled the sum of daily cash operating costs plus about $700/day/$1 million invested.

Land drillers

Lehman Bros.' Sedita believes the US land drilling business will continue to soften near-term and new rig construction adds additional risk. She expects more than 200 new land rigs to be delivered in the US this year, all under term contracts. The continued importation of LNG also affects natural gas drilling.

Sedita expects the US natural gas drilling market to bottom mid-year and begin to improve slowly later in the year or by early 2008. Sedita said that the US land drilling market is cyclical and driven by natural gas prices, therefore not as strong as the international and deepwater drilling markets.

Day rates are softening for specific rig classes. In the US, Sedita sees continued weak demand for lower-specification rigs (low horsepower rigs, mechanical rigs) as well as the very high (2,000-3,000 hp) rigs. She said the core market for 1,000-1,500 hp land rigs, however, has been surprisingly strong in both demand and day rates. Lehman Bros. expects continued high demand for 1,000-1,500 hp rigs as these rigs are utilized in core areas of US drilling and unconventional gas plays.

In Canada, Sedita sees the land-drilling market as extremely weak and expects continued low activity on a year-over-year basis. This has spurred some movement of Canadian rigs into the US market, but Sedita notes that "many of the Canadian rigs are not suitable for US drilling due to their smaller size...for use in shallow wells" [supersingles].

She added that the "inherent sharp decline curves of the US and Canadian [gas] markets, coupled with lower drilling activity, will help to support today's higher prices."

Nabors Industries is the world's leading contract land driller, with about 600 land drilling rigs, 780 land workover and well service rigs, and 65 offshore platform rigs. Nabors will take possession of 58 newbuild rigs in 2007 and has 45 more under construction, all with firm term contracts at high-margin day rates.

Nabors's size and diversification give it a better economic outlook than its peers, said Sedita, while the industry waits for a gradual land-rig market recovery later this year.

Patterson-UTI Energy Inc. is the second-largest contract driller in North America, with 403 land rigs. Sedita said PTEN's land rig fleet is likely to lose market share to companies with newer fleets and fewer mechanical rigs. She

also noted that Patterson-UTI has a less-aggressive construction program for new land rigs, which may depress 2007 estimated earnings, relative to companies that are building new rigs.

Construction

Lehman Bros. characterizes this as "the first significant new-build cycle during the past 25 years...[encompassing] all major geographic regions and...every asset class—land rigs, jack ups, and floaters."

In early May, Lehman Bros. oil service and drilling analysts Jim Crandell and Lisa Hackman noted National Oilwell Varco's "commanding market share" in land and offshore rig construction. They believe NOV's businesses will benefit in the "robust worldwide drilling markets" because of expanding demand for capital equipment.

NOV's rig technology group manufactures drilling rigs, rig equipment packages, coiled-tubing units, cranes, mooring systems, wireline units, nitrogen-injection units, and workover rigs. The group recently acquired Rolligan, a manufacturer of completion and service equipment such as frac units, blenders, data-acquisition systems, and coiled-tubing support units.

NOV's revenue from rig technology increased 7% to $1.22 billion in first-quarter 2007 from $1.137 billion in the prior quarter. Although new orders for capital equipment fell 14% to $1.2 billion from $1.4 billion in the prior quarter, NOV's backlog for rig equipment increased to $6.4 billion from $6.0 billion. And following the end of the quarter, NOV booked a $238 million drillship order.

NOV's backlog for land rig drilling equipment, however, dropped 33% to $1.2 billion from $1.8 billion in the prior quarter; it represented 18% of total backlog (down from 30% in the prior quarter). The company said that the demand for land-rig equipment weakened in North America but showed gains internationally during the quarter.

Meanwhile, NOV's offshore backlog increased 24% to $5.2 billion from $4.2 billion in the prior quarter. Of the current total backlog, the company expects to deliver about $2.5 billion in 2007, $2.1 billion in 2008, and the $1.7 billion balance thereafter—supporting Crandell and Hackman's belief that demand remains strong for drilling equipment, particularly offshore.

NOV's Petroleum Services and Supplies group provides consumable oilfield product such as transfer pumps, solids-control systems, drilling motors and other downhole tools, and rig instrumentation systems. The group's revenue increased 3% to $692 million in first-quarter 2007 from $670 million in the prior quarter.

Demand is strong in North America and internationally, although NOV saw declining revenue from Latin America. Low costs of some raw materials (nickel, copper, bronze) improved margins, but the company expects those costs to increase during second-quarter 2007.

NOV's Distribution Services group provides maintenance, repair, and operating supplies to drilling and production operations. Group revenue fell 5% in first quarter to $352 million from $371 million, largely due to reduced activity in Canada. This overshadowed gains in the US (Rockies, Gulf Coast) and internationally (North Sea, Saudi Arabia).

Cameron International's drilling and production systems group provides surface and subsea equipment. Cameron's surface orders were up 22% year-over-year, driven by Eastern Europe. Subsea orders were down 5% year-over-year, but order activity picked up in second quarter. In April, Petrobras awarded Cameron a $127 million contract to provide 22 subsea trees and the related control systems.

Lehman Bros.' Crandell and Hackman expect orders for 600 subsea trees in 2007, mostly for Africa (61%) and the Gulf of Mexico (20%). Cameron has about 30% market share for subsea trees, along with FMC (40%), Vetco-Gray (15-20%), Aker-Kvaerner (7-10%), and DrilQuip (less than 8%).

Cameron's drilling equipment orders fell 29% during first quarter and 47% year-over-year to about $200 million as offshore rig orders declined.

Future markets

At the OGIS conference in New York, Parker COO Mannon said, "Majors, super independents, and national oil companies are looking for large fields to develop. A lot are in frontier markets that demand rigs to drill deeper, more directional, and often employ extended reach technology."

He said a lot of the fields are in desert, arctic, and other environmentally sensitive areas. Shortages of personnel are a continuing problem, but Parker [and other companies] offer in-house crew training. HSE performance is often a critical performance variable, used as a measure to prequalify contractors and make purchasing decisions. ✦

Sinai well logging compares TDT, CHFR applications

G.M. Hamada
King Fahd University of Petroleum & Minerals
Dhahran

A.A. Hegazy
Petrobel Co.
Cairo

Logs from wells in a Sinai, Egypt, oil field provide a comparison between the use of thermal decay time (TDT) and cased-hole formation resistivity (CHFR) techniques for monitoring reservoir water saturation

Low water saturation suggests the zones may contain bypassed hydrocarbons.

The comparison of the two techniques showed that water saturations calculated from CHFR logs were more accurate than from TDT logs in most cases in these low-salinity reservoirs. The quick-look CHFR logs also always agreed with its quantitative interpretation, while the interpretation of the quick-look TDT log was difficult in most cases and often did not agree with the quantitative interpretation.

TDT logs also indicated water saturations greater than the CHFR log for the same intervals.

Interpretation of CHFR logs is easier than for TDT logs because the two factors used in the CHFR analysis have the same origin and are comparable with each others. These two factors are open and cased-hole resistivities. It is, therefore, easy to compare them and detect any differences.

In the case of TDT logs, the two factors compared with each other have different origins. These factors are TDT sigma and openhole resistivity, making a comparison difficult.

Monitoring saturation

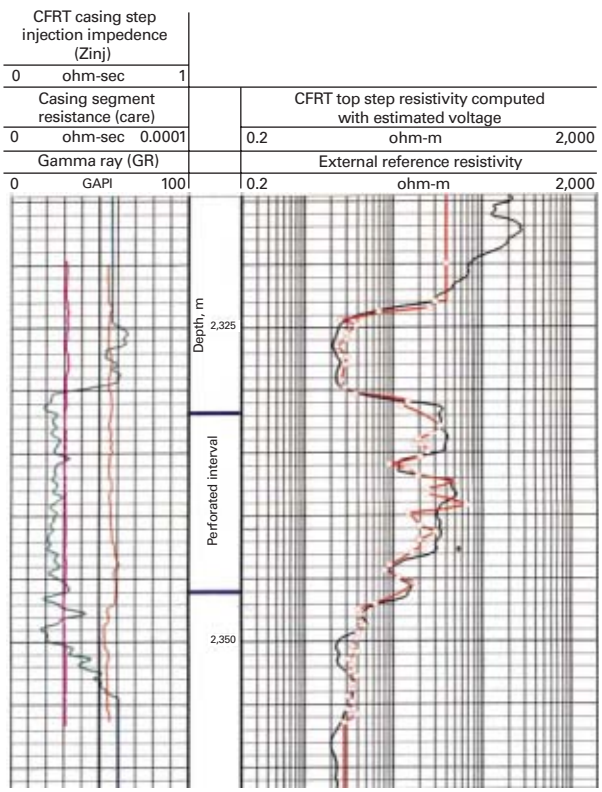
Continuous reservoir saturation monitoring, through cased wells, is the key for proper reservoir management and recovery optimization, especially for large and mature oil fields.

A TDT log has been the main technique for monitoring reservoir water saturations, but the log has problems in formations with low water salinity. This problem was obvious in some wells in the Sinai oil field that produce from sandstone formations.

Some of these reservoirs have naturally low 20,000-30,000 ppm water salinity. Also low salinity occurs in waterflooded reservoirs that use formation water diluted with less saline injected

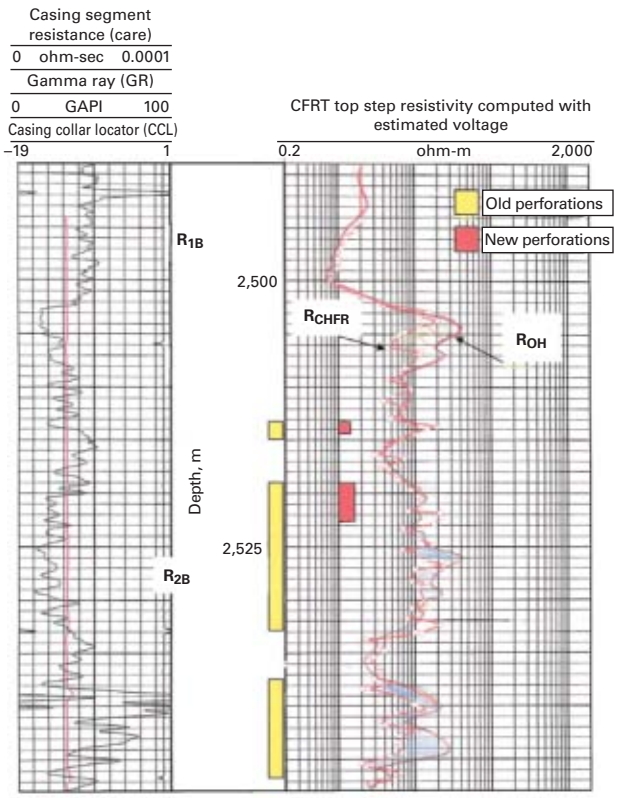
WELL A EXAMPLE

Fig. 1



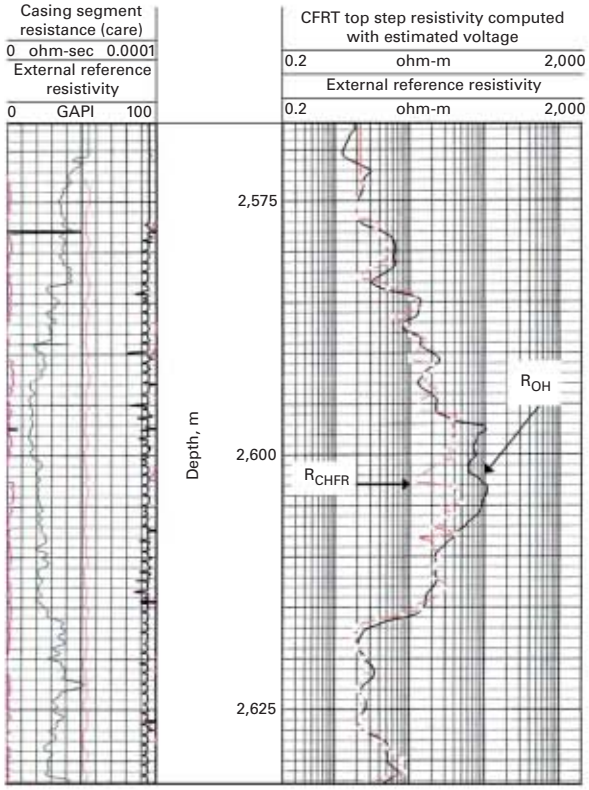
WELL B EXAMPLE

Fig. 2



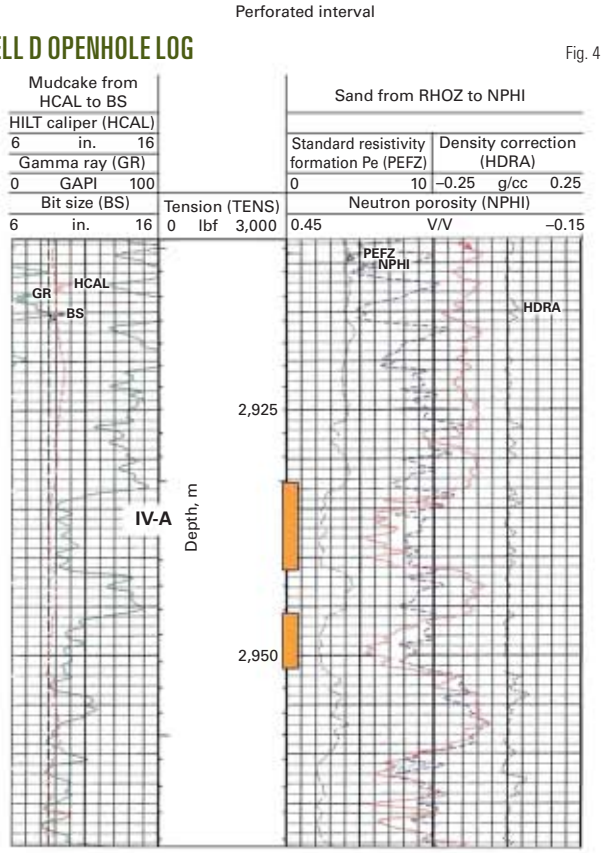
WELL C EXAMPLE

Fig. 3



WELL D OPENHOLE LOG

Fig. 4



water. Water injection projects in the field use Red Sea water with a 40,000-ppm salinity mixed with 150,000-ppm formation water.

TDT measurements depend on the chlorine (NaCl) content in the formation water; therefore, in zones with water salinity less than 60,000 ppm, a TDT cannot distinguish between water and oil. This problem was solved with the introduction of the carbon-oxygen (C/O) technique, which was combined with TDT technique into the RST tool.[1-3]

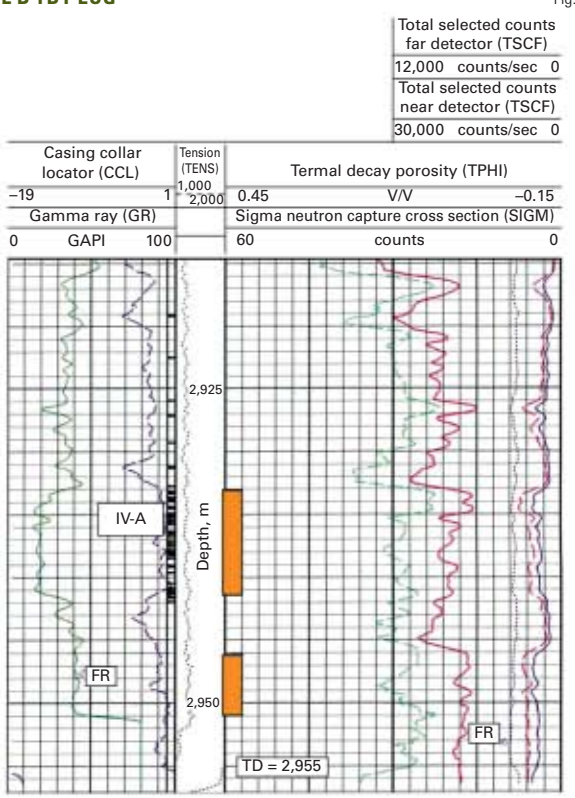
Other problems with TDT logs occur in wells with high pressure or wells that need to be killed before a workover.

Running TDT logs in wells completed with electrical submersible pumps (ESP) also in problematic. About 88 % of wells in the Sinai field have ESPs. The ESP string because it is close-ended prevents the TDT tool from reaching the producing formation. In this case, the production string must be pulled from the hole first, which requires killing the well with a heavier fluid that may invade the producing zone and influence the reading of the TDT log.

This problem may also be encountered in wells that produce with a high water cut and are shut-in for extended periods. In these wells water may invade the hydrocarbon-perforated zones. The TDT because of its short depth of investigation, about 1 ft, will be influenced by the invaded water in the near wellbore region. The RST tool did not solve this problem

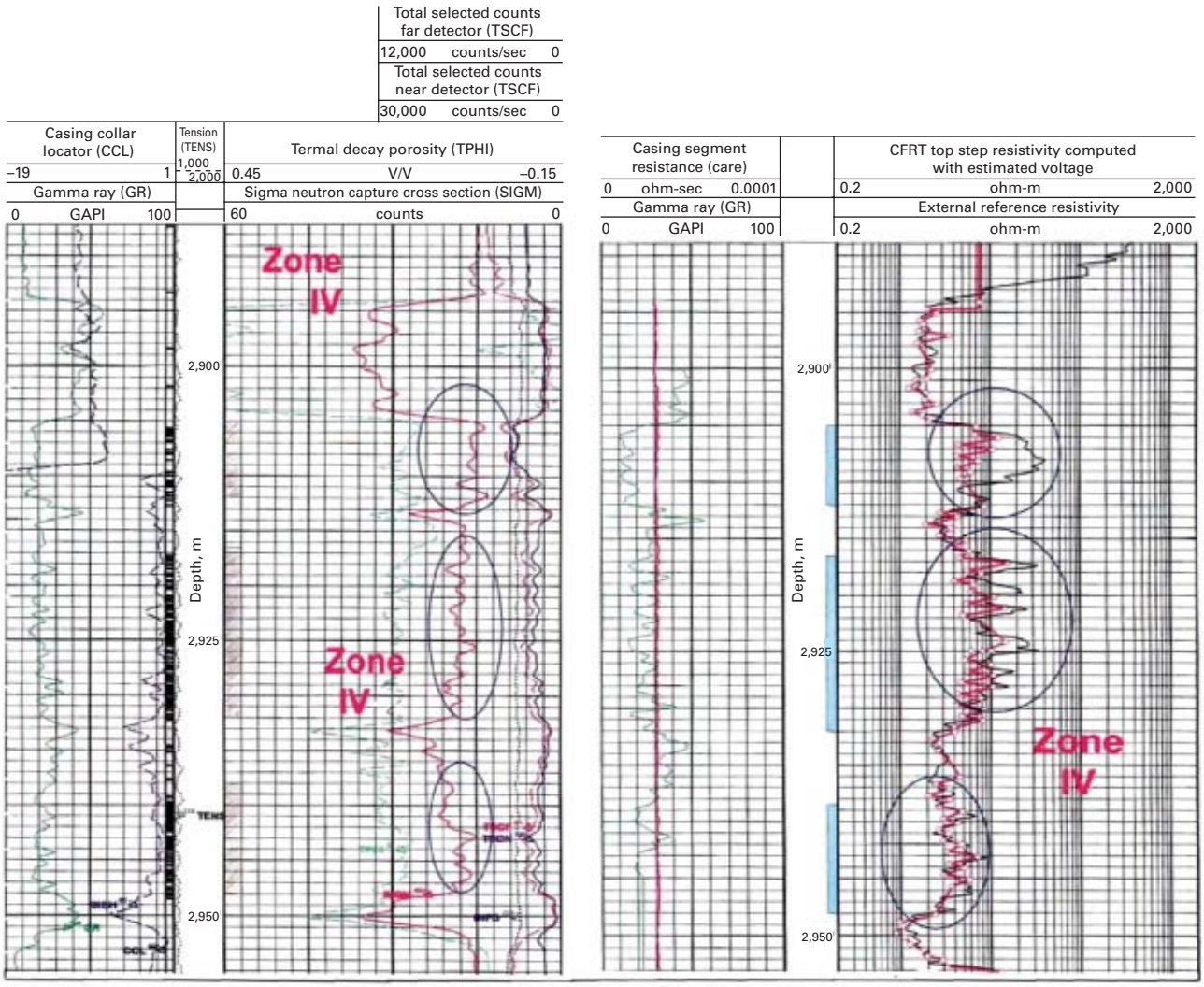
WELL D TDT LOG

Fig. 5



ZONE IV, WELL D TDT, CHFR COMPARISON

Fig. 6



because it has a short 6-8 in. depth of investigation, even shorter than the TDT.

For these reasons, the Sinai wells need anther type of cased-hole log for monitoring water saturation, although the field experience indicates that both the TDT and CHFR logs have advantages and limitations under certain conditions.

TDTs

Interpreting TDTs based on a time-lapse technique is the most useful and practical approach. This technique requires the running of a reference log soon after completing the well. Equation 1 (see equation box) then can be used to compute the change in water saturation.[1,4] This technique has the disadvantage that many wells do not have a reference log or base TDT because these runs must be made a few weeks after the initial completion. For wells such as subsea completion, recording a TDT base run a few weeks after completing the well is impractical.

The reliability of a TDT quantitative evaluation generally increases with greater formation porosity and water salinity. This evaluation is based on the summation of the cross-section of all material multiplied by their respective volume proportions. In the general case of a shaly porous formation containing water and hydrocarbons, Equation 2 calculates the water saturation, S_w from a TDT log.[2,4]

The TDT technique is limited by the following:

- Not for formations that have low formation-water salinities because measurement depends on the capturing of neutrons of the chlorine nuclei of NaCl dissolved in formation brine.
- Not for formations with different salinity brines.
- Not for formations with near wellbore effects, formation damage, or washed-out holes because of the logs short depth of investigation.
- Not for formations with low po-

rosity (<15%).

- Not for acidized wells.
- Difficult to interpret the TDT log with a cross plot if the well has no logged aquifer or water zone along with the hydrocarbon zone.
- Not for wells producing with ESPs because of the closed end in the tubing and the requirements to kill the well with fluids that may invade the formation.

CHFRs

The CHFR resistivity tool has a much greater investigation depth then the nuclear logging tools used for through-casing evaluation. The CHFR evaluation is also possible in low porosity and low formation-salinity zones.[5-9]

Because the CHFR log provides cased-hole resistivity values that resemble openhole resistivity values (R_{OH}), the quantitative interpretation of CHFR logs is similar to openhole log quantitative interpretation with the Archie equation.

Equation 3 shows the Archie equation for determining water saturation (S_w) from true formation-resistivity logs for clean formation.[5]

Equations

$$\Delta S_w = \Delta\Sigma\log/\Phi(\Sigma_w - \Sigma_h) \quad (1)$$

$$S_w = (\Sigma_{log} - \Sigma_{ma}) - \Phi(\Sigma h - \Sigma_{ma}) - V_{sh}(\Sigma_{sh} - \Sigma_{ma})/\Phi(\Sigma_w - \Sigma_h) \quad (2)$$

$$S_{w(CHFR)} = (FR_w/R_{CHFR})^{0.5} \quad (3)$$

$$DI = (R_t/R_{CHFR})^{0.5} \quad (4)$$

The depletion-indicator (DI) s the ratio of the reference openhole to new cased-hole Archie water-saturation values (Equation 4). DI can be plotted vs. depth for a formation, taking the value 1 as a base line, below which the formation can be considered as it is depleted: R_{CHFR} less than R_{OH}.[5 10]

Low-resistivity cements typically found in oil wells do not degrade the measurement, but highly resistive cements (>8 Ω-m.) will require a correction.

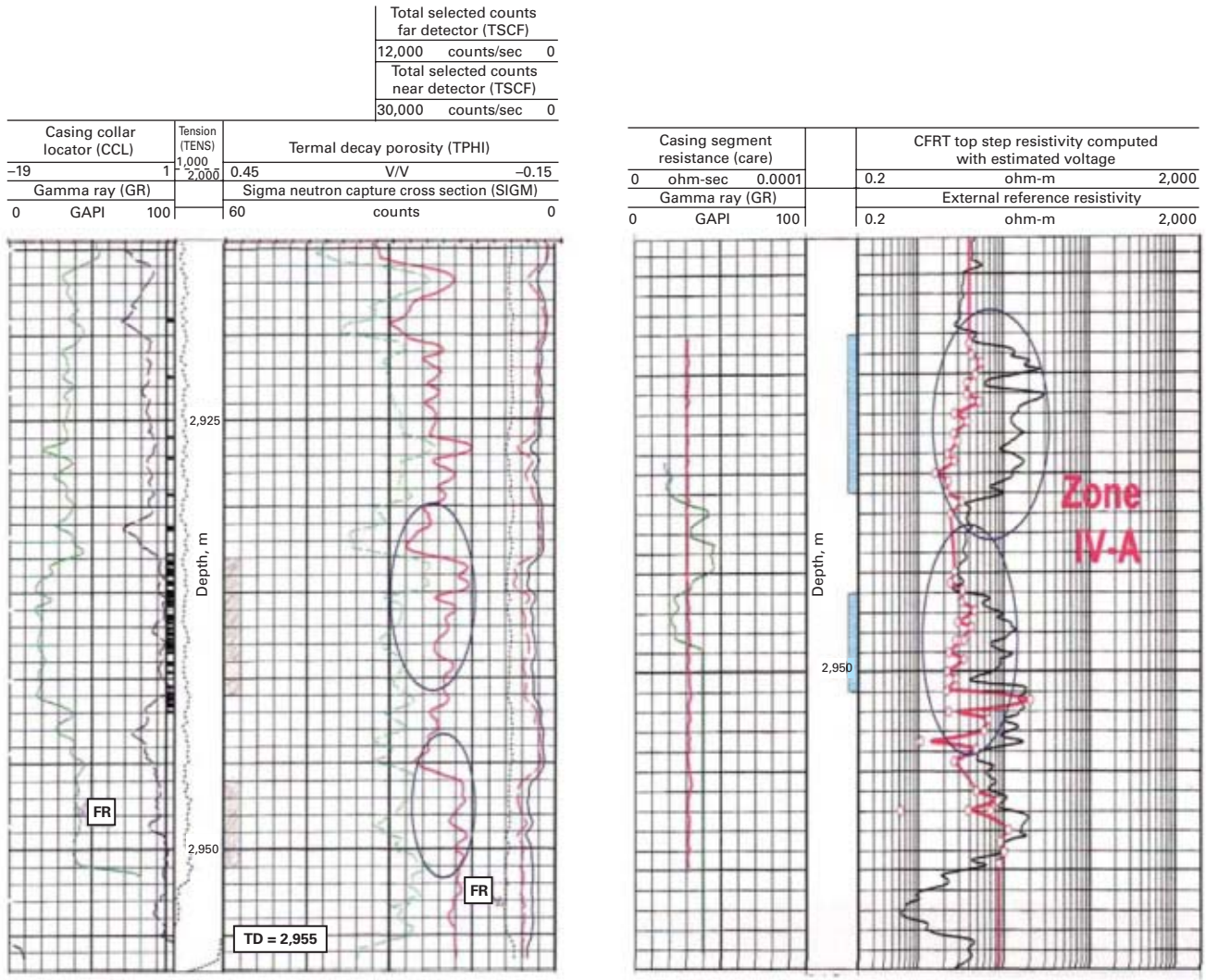
Another problem is that casing scales may inhibit contact between the electrodes and the casing, necessitating a scraper run before running the CHFR tool. The tool also may not make good contact at casing collars and thus may lose 4-6 ft of data. Casing collars can cause distortions up to 10-20% of formation resistivity. The current CHFR tool cannot be run inside tubing.

Tool contact with the casing may be impaired if the casing has a non-conductive coating. In other instances, the electrodes may contact the casing by scratching away the coating, meaning that the CHFR measurement would be unaffected but that corrosion may be induced.

The CHFR is not designed to operate in dual casing strings because these

ZONE IV-A, WELL D TDT, CHFR COMPARISON

Fig. 7



installations have too many variables to enable quantifying formation resistivity.[11-14]

CHFR field examples

The first field example is from Well A, the first well in the field logged with a CHFR tool. The log was recorded after running of an openhole resistivity log and setting the casing. Fig. 1 shows that the CHFR and the openhole LLD data have a good match. This logging data comparison is an important step for testing and evaluating CHFR data to monitor water-saturation changes.

The next example, Well B, shows the use of CHFR logging technique based on determining the difference between CHFR resistivity and openhole resistivity. These logs are from a well that has been on production for the years and produces 2,700 b/d of total fluid from a 90-m shaly sand layer. Fig. 2 shows the old perforations from which the well started producing a 49.5% water cut.

This well is completed in a reservoir with a mixed, 90,000-ppm water salinity. The aquifer water has a 150,000 ppm while the injected water has a 40,000-ppm salinity.

This current formation-water salinity complicates use of a TDT to monitor changes in reservoir water saturation; therefore, a CHFR was used to evaluate the water cut problem. The CHFR was recorded over the interval 2,495-2,523 m.

The comparison of openhole LLD and CHFR logs (Fig. 2) showed that the CHFR resistivity is generally lower than the openhole resistivity in intervals R2A and R2B, indicating that these are depleted and flooded zones.

A squeeze job on the 2,513-43 m interval and reperforating selectively the total interval (Fig. 2) to avoid the flooded out zones reduced the water cut. The work reduced the total production to 1,500 b/d with the water cut decreasing to 0.8%.

A third example, Well C, initially produced 820 b/d total fluid, 0.8% water cut, with an ESP from sandstone reservoirs. After the water cut increased and reached 72.3%, the operator decided to make a logging run to determine the reason for the high water cut. Because the formation has a low, 22,000-ppm water salinity, the CHFR was selected instead of the TDT.

Fig. 3 compares the CHFR resistivity and openhole resistivity. The logging data clearly show that the middle of the perforated interval, 2,589-2,615 m, is the source of the water.

After squeezing of the waterflooded interval 2,595-2,611 m, water cut decreased to about 35%.

TDT field examples

Well D is an oil producer with an ESP. Initial production was 1,260 b/d of fluid with a 1.6% water cut. Fig. 4 shows openhole log of the producing sand and shaly sand intervals (2,804-12, 2,816.5-32, and 2,832.5-48 m).

After 2 years of production, water cut reached 62.3%. Formation-water salinity was about 178,000 ppm; therefore, the operator decided to run TDT for detecting the waterflooded zone.

Fig. 5 shows the TDT data for the same intervals. The TDT interpretation indicated that waterflood intervals were 2,816.5-32 and 2,832.5-48 m. Based on this interpretation, the operator isolated the lower intervals, but this did not change the water cut and the work decreased oil production.

Another example is the lower section of Well D that initially produced 600 b/d. Producing intervals were mainly sand and shaly sand at 2,933-41 and 2,946-51.

Fig. 4 shows the openhole data, neutron-density logs indicating clearly the producing sections. Fig. 5 illustrates the TDT for the same intervals with the TDT sigma curve clearly showing that the waterflooding of the producing intervals. The interpretation of the TDT indicates that the water is coming form Zone IVa.

TDT, CHFR comparison

A CHFR may replace a TDT log in cases where reservoir conditions or well completions are unsuitable for running a TDT log. Also CHFR logs can clarify any confusion in the TDT interpretation.

One major problem with the TDT is the difference between quick-look interpretation of the TDT log and the quantitative interpretation of the TDT with a water saturation model.

Fig. 6 compares the TDT and CHFR for Zone IV, Well D, and Fig. 7 compares the TDT and CHFR for Zone IVA, Well D.

The quick-look interpretation of the TDT indicates that the lower sections of Zone IV and IVa were waterflooded; whereas the CHFR indicates that only the upper section of IV and lIVa were waterflooded.

WELL D LLD, TDT, CHFR COMPARISON

Fig. 8

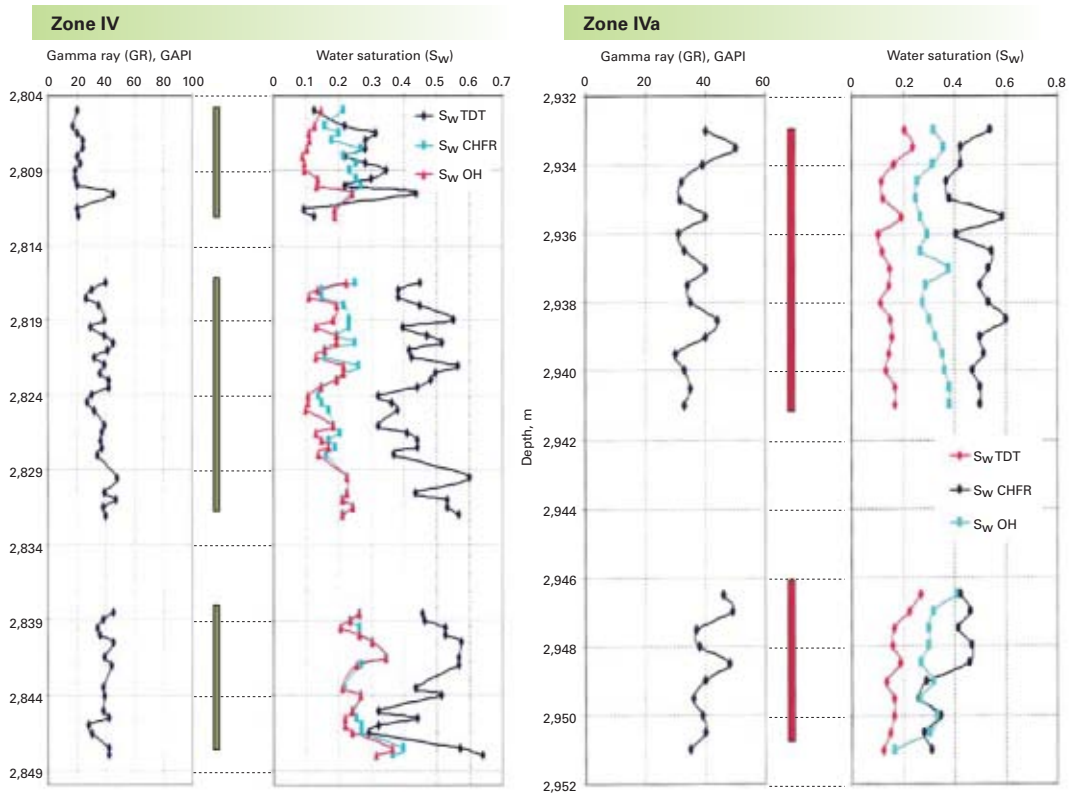


Fig. 8 shows a quantitative interpretation of openhole data, TDT, and CHFR for Zone IV. The TDT interpretation shows that the entire section was flooded, which disagrees with the TDT quick-look interpretation.

The CHFR interpretation indicated that only the top section was waterflooded, which agrees with the CHFR quick interpretation.

Fig. 8 also shows the quantitative interpretation of openhole log, TDT, and CHFR for Zone IVa. Both the TDT and CHFR indicated that this is a flooded zone.

Worth noting is that the TDT shows more water saturation difference with reference openhole water saturation, indicating more flooding than the CHFR.

The difference between openhole saturation profile and CHFR or TDT saturation profiles indicates that Zone IVa and the top section of Zone IV were producing zones, but now water has swept these zones.

Based on TDT data interpretation, the operator isolated Zone IVa, but the water cut was not reduced.

But based on the CHFR data interpretation, the operator isolated Zone IVa and the upper section of Zone IV, thereby reducing the water cut to 38% from 62.3%. The water cut has continued to decrease to 2%.

Acknowledgment

The authors thank Petrobel Co. for permitting publication of well logging data and thank King Fahd University of Petroleum & Minerals for supporting this work. ✦

References

1. Morris, F., et al., "Applications of Pulsed Neutron Capture Logs in Reservoir Management," Paper No. SPE 93889, SPE Western Regional Meeting, Irvine, Calif., Mar. 30-Apr. 1, 2005.

2. Hamada, G.M., and Hiekal, S.A., "Gas Detection Model Applied to Heterogeneous Reservoirs Using TDT," Paper No. JJJ, SPWLA 39th Annual Logging Symposium, Keystone, Colo., May 26-29, 1998.

3. Aldred, R.D., "Interpretation of Pulsed-Neutron Data in Low-Salinity Environments Without Base Logs," Paper No. SPE 25374, SPE Asia Pacific Oil & Gas Conference & Exhibition, Singapore, Feb. 8-10, 1993.

4. Rinehart, C.E., and Weber, H.J., "Measuring Thermal Neutron Absorption Cross Sections of Formation Brines," Paper G, SPWLA 17th Annual Logging Symposium, New Orleans, June 9-12, 1975.

5. Dubourg, I., et al., "Resistivity Behind Casing." OilField Review, Schlumberger, Spring 2001, pp. 2-25.

6. Hunka, J.F., et al. "A New Resistivity Measurement System for Deep Formation Imaging and High-Resolution Formation Evaluation," Paper No. SPE 20559, SPE ATCE, New Orleans, Sept. 23-26, 1990.

7. Singer, B.S., et al., "Measurement of Formation Resistivity Through Steel Casing," Paper No. SPE 30628, SPE ATCE, Dallas, Oct. 22-25, 1995.

8. Maurer, H.M., and Henniker, J., "Early Results of through Casing Resistivity Field Tests," Paper No. DD, SPWLA 41st Annual Logging Symposium, Dallas, June 4-7, 2000.

9. Beguine, P., et al., "Recent Progress on Formation Resistivity Measurement Through Casing," Paper No. CC, SPWLA 41st Annual Logging Symposium, Dallas, June 4-7, 2000.

10. Ferguson, R., et al., "Direct Measurement of Formation Resistivity Through Steel Casing Solves a North Sea

Production Question," Paper No. SPE 71715, SPE ATCE, New Orleans, Sept. 30-Oct. 3, 2001.

11. Hupp, D., et al., "Cased Hole Formation Resistivity Application in Alaska," Paper No. SPE 76715, SPE Western Regional/AAPG Pacific Section Joint Meeting, Alaska, May 20-22, 2002.

12. Starcher, M., et al., "Next Generation Waterflood Surveillance: Behind Casing Resistivity Measurement Successfully Applied in the 'A3-A6' Waterflood at Elk Hills Field," Paper No. SPE 76730, SPE Western Regional/AAPG Pacific Section Joint Meeting, Alaska, May 20-22, 2002.

13. Ma, S.M., et al., "Looking Behind Casing: Evaluation and Application of Cased Hole Resistivity in Saudi Arabia," Paper No. SPE 88467, SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, Oct. 18-20, 2004.

14. Murty, C.R.K., et al., "Analysis Behind Casing: A Window for Improved Reservoir Management of a Mature Bahrain Oil Field," Paper No. SPE 93582, 14th SPE Middle East Oil & Gas Show and Conference, Bahrain, May 12-15, 2005.

The authors

Gharib M. Hamada (ghamada @kfupm.edu.sa) is professor of well logging and applied geophysics at King Fahd University, Saudi Arabia. Previously he was with Cairo University, Technical University of Denmark, Sultan Qaboos University, and King Saud University. His main research interests are well logging technology, formation evaluation, and seismic data analysis. Hamada holds a BS and MS in petroleum engineering from Cairo University, and a DEA and. D'Ing from Bordeaux University, France. He is a member of SPE and SPWLA.

Ahmed El.M. Hegazy is a petroleum engineer at Petrol Belyem Petroleum Co. (Petrobel), Cairo. Hegazy holds a BS and an MS in petroleum engineering, from Cairo University, Egypt.

Offshore processing plant uses membranes for CO_2 removal

Alan Callison
NATCO Group Inc.
Houston

Graham Davidson
Carigal Hess Operating Co.
Kuala Lumpur

The Cakerawala production platform (Figs. 1 and 2), an offshore processing facility in Block A18 of the Malaysia Thailand Joint Development Area in the Gulf of Thailand, installed semipermeable membranes to lower the CO_2 content in its produced gas.

The CO_2-removal process on the Cakerawala production platform (CKP) uses Cynara semipermeable membranes. The facility was successfully commissioned in December 2004 and is currently continuing to operate.

CKP gas treating

Carigali Hess Operating Co. Sdn. Bhd., a joint venture of Petronas Carigali Ltd. and Hess Oil Co. of Thailand Ltd., operates the plant, 150 km offshore (Fig. 3), for the Malaysia-Thai Joint Authority.

Raw untreated inlet gas to CKP with about 37% CO_2 has a sales-gas specification of less than 23% CO_2 before being delivered to the buyer's pipeline.

The low-CO_2 sales gas produced is compressed and routed to southern Thailand in a 34-in. subsea 270-km pipeline, owned and operated by Trans-Thai Malaysia on behalf of the gas buyers. There, the gas is used primarily for power generation and chemical industries in Thailand and Malaysia.

Due to a delay in the onshore gas processing plant, a new specification of 10% CO_2 was needed, with an operating specification of 8% to provide an adequate operating margin. Even though initial operating requirements of 8% CO_2 sales gas were significantly different from the design conditions of 15-23% CO_2, the membrane system was adaptable to the new design condition and allowed Carigali Hess to operate to this markedly different specification.

The flexibility of the installed Cynara

Based on a presentation to the Laurance Reid Gas Conditioning Conference, Feb. 25-28, 2007, Norman, Okla.

The Cakerawala production platform is moved into position in the Gulf of Thailand (Fig. 1).

membrane system allowed Carigali Hess to begin gas production about 8-9 months earlier than would have been otherwise possible.

The Cakerawala production facility can produce 425 MMscfd of sales gas with a final CO_2 specification of 15% (Fig. 2).

Design

During conceptual design, the project developers evaluated different processes for gas separation for use at CKP. Those processes included CO_2 membranes, pressure swing adsorption, amines, and cryogenic distillation (Ryan Holmes process). Fig. 4 shows the different types of processes.

In 1999, CO_2 membranes were selected instead of other technologies for CKP due to environmental considerations and space and weight savings.

A technical and commercial evaluation was then conducted of different CO_2 membrane suppliers. In 1999, a contract was awarded to NATCO to design and build the required membrane system for CKP Phase 1. In addition to the membrane CO_2-removal system, the scope of supply included the gas pretreatment system, dehydration, cooling, and liquids separation for condensate recovery.

To assist with design specifications NATCO launched a pilot operation in Snyder, Tex. This pilot operation was used to help better identify exact design considerations and was developed with nearly identical operating conditions to those expected for CKP operation.

CAKERWALA PRODUCTION PLATFORM LOCATION

Fig. 3

CKP membrane description

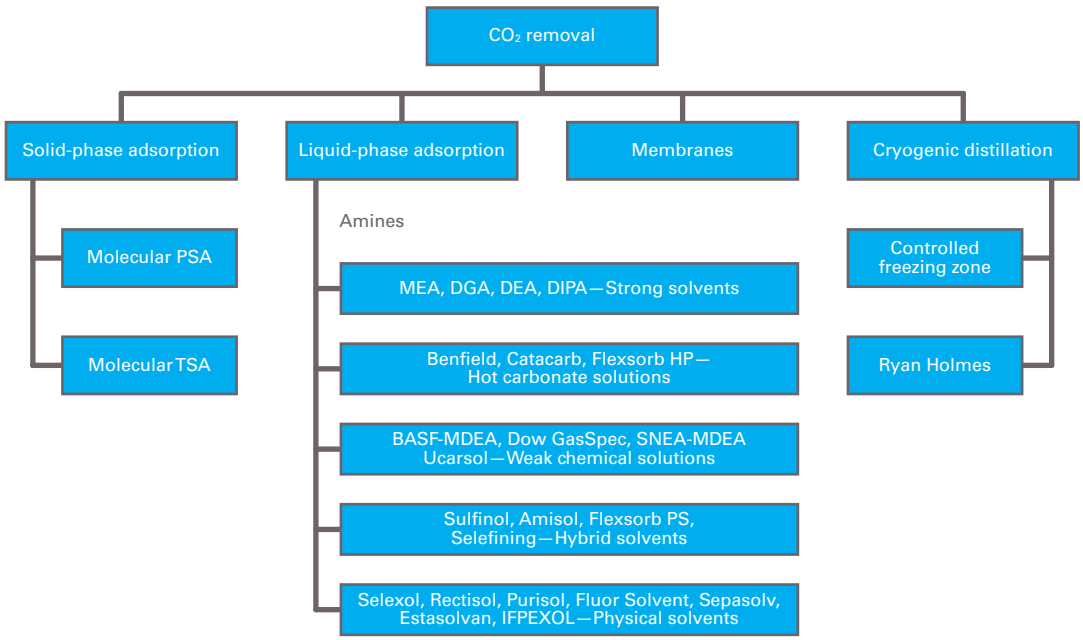
The design condition of the membrane plant was to deliver 425 MMscfd of sales gas containing 15% CO_2 from a feed-gas volume of 700 MMscfd and feed CO_2 concentration of about 37%. Design pressure to the membranes is 630 psig (43.4 barg).

The sales-gas agreement called for the CO_2 content in the sales gas to be less than 23%; for design purposes, however, 15% was chosen as the design point. This enabled Carigali Hess to take advantage of higher heating value at the lower CO_2 condition, which translates to more revenue at the same export volumes.

Designing for 15% also provided

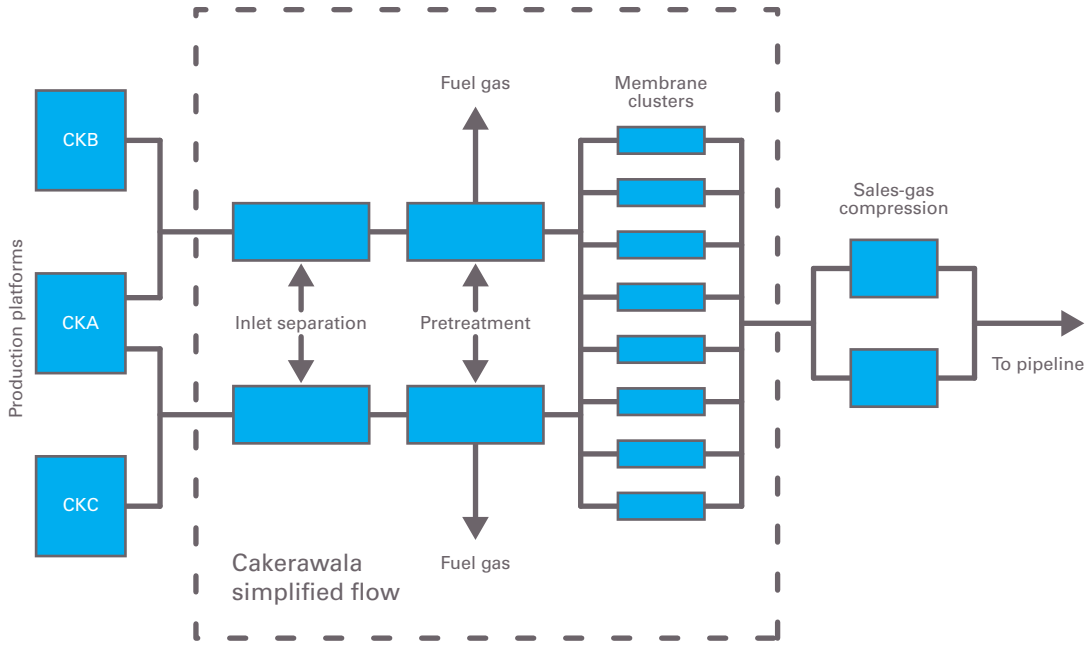
CO_2-REMOVAL PROCESSES

Fig. 4



CKP FLOW SCHEME

Fig. 5



considerable operating margin and, therefore, increased operating flexibility.

The membrane CO_2-removal system consists of two 50% gas-pretreatment trains. This conditions the raw well-stream gas before it enters the membranes clusters (Fig. 5).

Each train consists of inlet cooling, dehydration that uses desiccant beds (silica gel), dry-gas filters, and gas chilling with mechanical refrigeration (propane as refrigerant). Energy recovery from the cold membrane streams through a series of heat exchangers and a closed-loop chilled water system minimizes the refrigeration duty.

The membrane clusters themselves consist of four separate subtrains in each 50% pretreatment train (eight clusters in total) all operating in parallel.

Each cluster operates as a two stage, CO_2-removal process (eight elements in each stage), with the low CO_2 nonpermeate product stream from the first stage routed as feed gas to a second stage.

Fig. 6 shows a simplified schematic of a membrane cluster.

Each cluster therefore contains 16 total membrane elements each housed in individual enclosures (Fig. 7). The membrane elements are 16-in. diameter.

The nonpermeate from the second stage (at about 15% CO_2) feeds the sales-gas compressors where it is compressed, metered, and delivered to the pipeline for transport onshore.

The combined low pressure, high-CO_2 permeate streams from all membrane clusters are routed to flare. Permeate streams from each individual cluster can be delivered to either the low-pressure permeate header that goes directly to flare or to a higher-pressure permeate header where

DEEP OFFSHORE TECHNOLOGY

International Conference & Exhibition

D.O.T

D'O'L®

DEEPWATER & ARCTIC-
OCEANS OF NEW OPPORTUNITIES

October 10 - 12, 2007
Stavanger Forum, Stavanger, Norway

www.deepoffshoretechnology.com

The Deep Offshore Technology International Conference & Exhibition (DOT) will be held in Stavanger, Norway this year with over 2500 people and 100 exhibitors expected from the energy centers of Norway, United States, Asia, Europe, Russia, Brazil, Venezuela, Colombia, and Australia.

As technology rapidly changes in our industry this year's conference theme "Deepwater & Arctic – Oceans of New Opportunities" addresses all the capabilities of our industry and will attract a broad collection of papers on topical subjects related to both deepwater exploration and the complexities of arctic exploration. At this year's DOT, a special session on arctic technology will reflect the growing importance of arctic exploration frontiers.

PennWell is committed to bringing DOT to the world's most pertinent deepwater markets. Norway is central to Arctic worldwide offshore E&P market and many prominent players in the oilfield will gather for this most prestigious conference and exhibition.

Plan on exhibiting, sponsoring and attending this event as DOT travels to Norway for the latest in deep offshore technology.

Conference Management Contacts:

Conference Director
ELDON BALL
P: +1 713 963 6252
F: +1 713 963 6296
dotconference@pennwell.com

Exhibit & Sponsorship Sales Managers:
JANE BAILEY
P: +44 (0) 1992 656 651
F: +44 (0) 1992 656 700
janeb@pennwell.com

SUE NEIGHBORS
P: +1 713 963 6256
F: +1 713 963 6212
dotsales@pennwell.com

Owned & Produced by: PennWell

Flagship Media Sponsors: Offshore, Oil&Gas Journal, Oil&Gas

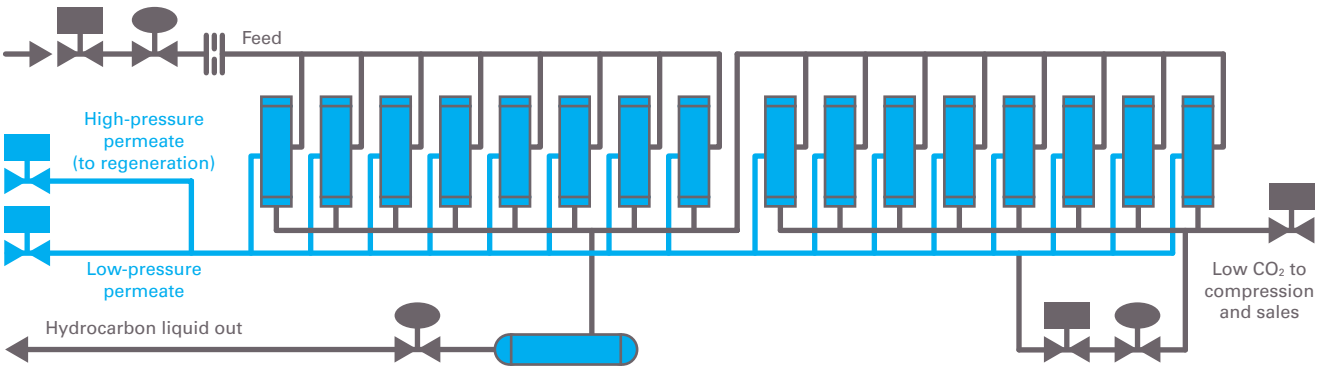
Hosted by: Statoil

Supported by: GEP, INTSOK, NCE Subsea

Sponsored by: Schlumberger, CAMERON, INTEC ENGINEERING

MEMBRANE CLUSTERS

Fig. 6



it is used for regeneration gas in the pretreatment dehydration system and then delivered to the same flare as the low-pressure permeate.

The difference in permeate pressure between the low-pressure permeate and high-pressure permeate is about 30 psig (2 barg), with actual pressures of 25 psig and 55 psig, respectively.

The higher permeate pressure reduces membrane selectivity and capacity so that only the minimum quantity of clusters that will furnish the required regeneration gas flow rate are placed in the higher permeate pressure operation. Other clusters remain in low permeate pressure operation to maximize selectivity and overall capacity. Each cluster can be automatically controlled to deliver the cluster permeate to either the low-permeate-pressure system or the higher permeate pressure system.

This photo shows one of the 16-in. membrane elements before being installed in its individual enclosure (Fig. 7).

The Cynara membranes at CKP were designed to operate with a low feed-gas temperature (–7° C.) and without superheat. Gas entering the membrane clusters is at its hydrocarbon dewpoint and hydrocarbon condensation occurs as CO_2 is removed from the gas stream.

The system was designed with vertical membranes in which the formed hydrocarbon liquid can easily be drained away from the membranes. The process of CO_2 removal also results in a significant temperature reduction across the membranes and affects all of the streams separated in the membrane system.

This cooling effect of the membrane-processed streams is used to reduce refrigeration loading in the pretreatment section. Each of these cooled product streams is optimized in the pretreatment section with cross exchangers—product is on one side and a water-glycol mix is on the other.

This water-glycol loop is a closed loop chilled-water system, which reduces process gas temperature upstream of the mechanical refrigeration system, thereby significantly reducing refrigeration duty.

Initial operations

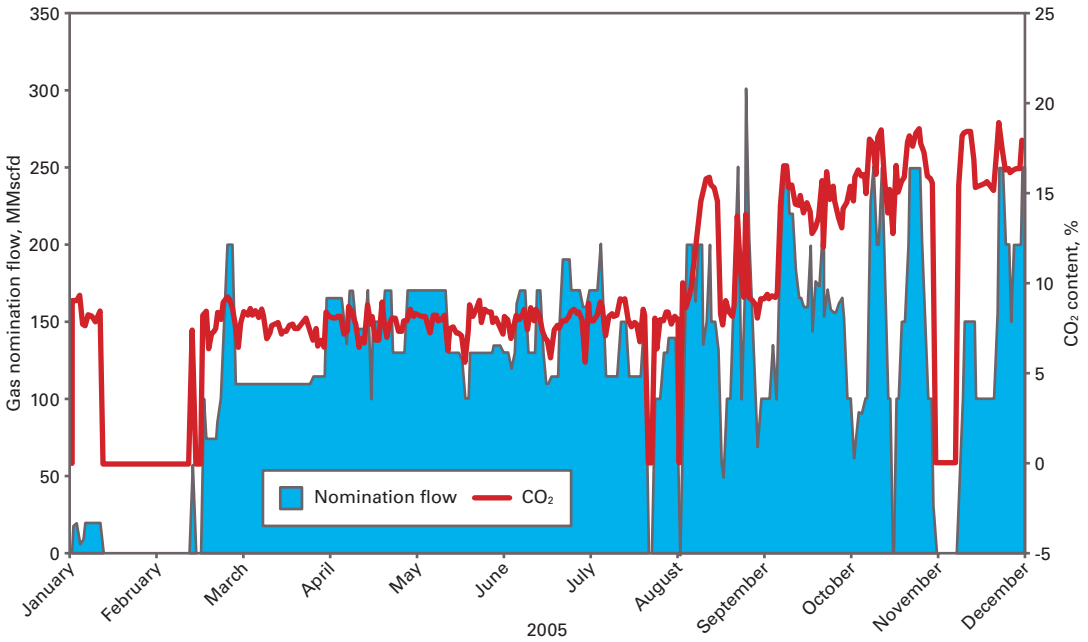
The design basis of the membrane system was to deliver less than 15% CO_2 in the sales gas to the pipeline. A delay in construction of an onshore gas processing plant led to the signing of an interim sales-gas agreement for the initial operations.

This agreement called for a reduced sales-gas flow rate of 200 MMscfd, with less than 10% CO_2 content. This meant that gas produced on the platform would bypass the onshore gas plant and feed directly into the onshore gas grid.

The CKP facility, therefore, had to be

MEMBRANE PERFORMANCE

Fig. 8



commissioned and proven to a much stricter sales-gas specification than that for which it was originally designed.

NATCO simulated the new design parameters to determine the effects of operating at this new CO_2 level, not only on the actual membrane performance, but also the supporting utilities, especially the chilled-water loop.

To ensure an adequate operating margin below the new 10% CO_2 spec, operating at 8% CO_2 was required. The simulations showed that a product sales-gas rate of 280 MMscfd could be achieved with all eight clusters online (128 membranes) at the required 8% product specification.

Only six clusters were therefore required to be online initially to meet the required 200 MMscfd sales-gas rate at 8% CO_2, thus providing sufficient sparing of membrane capacity.

The membrane system commissioning was performed in conjunction with the total platform start-up. Commissioning and start-up of the membrane system consisted of:

- Pretreatment, start-up, and initial regeneration of all four dehydration beds on each train.
- Purging of each membrane cluster (empty) at a sufficient rate to flush any foreign matter.
- Start-up of one membrane cluster with the 16 service elements to prove anticipated performance at the lower CO_2 case and to tune all control parameters.
- Final sales-gas production into the pipeline.

Start-up activities commenced in early November 2004, with commissioning of the first CO_2 pretreatment train soon thereafter.

Cluster commissioning began in late November 2004 and continued through December 2004. After the commissioning of each cluster, the 16 actual service membrane elements were prepared and installed.

On Dec. 11, 2004, the first cluster was started up with 16 new service elements to provide an indication of anticipated performance at the lower CO_2 case. Feed gas was introduced at the rate that had been anticipated for a fully loaded cluster to produce 8% CO_2 product.

Also, as a result of information gathered from pilot testing and supporting information from lab research and other operating facilities, NATCO recommended a slightly warmer membrane feed temperature of 2° C.

This warmer temperature would result in nearly identical separation and permeability characteristics; but over the long term, this would extend membrane lifetime and performance.

At this off-design condition, the initial performance result matched the performance that NATCO expected based on 2001 in the pilot plant. The results showed that the initial performance was better than expected (for the less than 10% CO_2 operating case), particularly in terms of separation, with lower-than-expected hydrocarbon losses. The required feed rate was only about 1.4 times the nonpermeate rate, compared with an expected factor of about 1.65. This indicated the vent losses were lower than expected during initial operation.

During this interim period, however, the membrane performance was lower than anticipated. There were several factors that contributed to this:

- Widely varying inlet gas flow rates due to rapidly changing sales-gas nomination flow rates (Fig. 8). Membranes prefer stable operations. Regular start-ups and shutdowns will accelerate declines in performance.
- Colder than original design feed gas temperatures of –7° C. and moving further away from recommended temperature of 2° C. There were some turndown issues with the refrigeration system. At lower flow rates, it was difficult to control the system at the warmer temperatures required.

OIL SANDS & HEAVY OIL TECHNOLOGY

Conference & Exhibition

OIL SANDS HEAVY OIL TECHNOLOGIES™

OIL SANDS AND HEAVY OIL

Plan to attend these high profile conferences designed to assist in your oil sands and heavy planning!

July 18 – 20, 2007
Calgary TELUS Convention Centre, Calgary, Canada

www.oilsandstechnologies.com

The oil sands and heavy oil industries are dynamic markets for both the energy and power business sectors. Quickly advancing development of oil sands and heavy oil assets is creating a hugedemand for technology and services. Cogeneration of power is driving facilities and infrastructure growth.

PennWell Conference's and Exhibitions now provides a premium event for this important industry – the Oil Sands and Heavy Oil Technologies Conference & Exhibition. This pivotal conference and exhibition provides a sophisticated new venue where buyers and sellers meet, learn and build business relationships.

For this year, the conference will focus on subjects such as:

- Steam Generation
- Heat & Power
- Emissions
- Water
- Alternative Fuels
- Project Management
- Mining
- In Situ
- Upgrading (with panel discussion)
- CO_2 (with panel discussion)

Mark your calendars and plan to be with us as PennWell continues to bring major conferences and exhibitions to the world's most pertinent energy markets.

Conference Management Contacts:

Conference Manager:
GAIL KILLOUGH
P: +1 713 963 6251
F: +1 713 963 6201
oilsandsconference@pennwell.com

Exhibit & Sponsorship Sales:
JANE BAILEY (PETROLEUM)
P: + 44 (0) 1992 656 651
F: +44 (0) 1992 656 700
Email: janeb@pennwell.com

BOB LEWIS (POWER)
P: +1 918 832 9225
F: +1 918 831 9875
blewis@pennwell.com

SUE NEIGHBORS (PETROLEUM)
P: +1 713 963 6256
F: +1 713 963 6212
oilsandssales@pennwell.com

Owned & Produced by: PennWell, Offshore

Flagship Media Sponsors: OIL&GAS JOURNAL, POWER Engineering

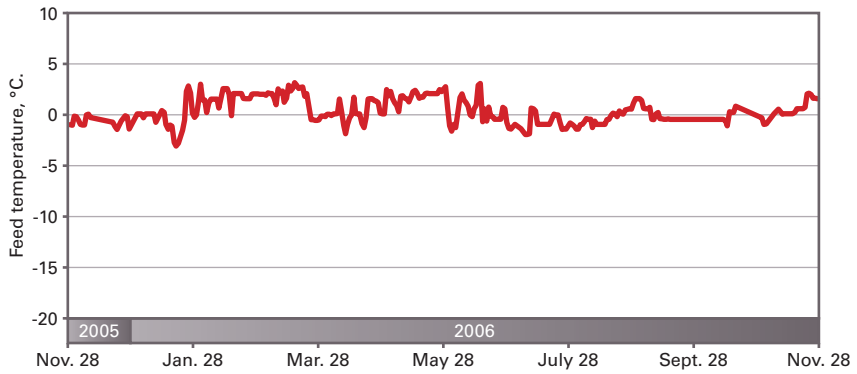
Gold Sponsor: ALSTOM

Silver Sponsor: DOCKWISE

Sponsored by: HALLIBURTON, Sargent & Lundy LLC, TECHSTREET

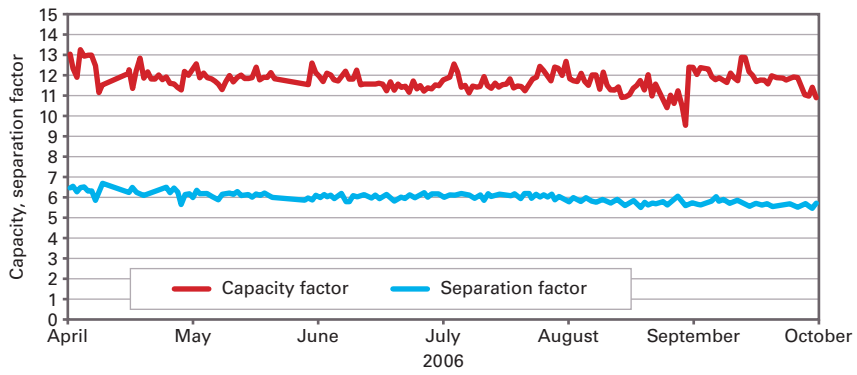
MEMBRANE FEED GAS

Fig. 9



TRAIN 2, CLUSTER 1 PERFORMANCE

Fig. 10



• Less CO_2 in the sales gas requires lower temperatures across the membrane system due to the required higher percentages of feed gas that must be permeated.

Current operations

During second-half 2005, the onshore gas processing plant was commissioned. This allowed CKP operations to revert to the original design condition; sales gas had 15-18% CO_2. Additionally, the flow conditions became much more stable with fewer shutdowns and the problems with chiller temperature control were resolved.

Carigali Hess was therefore comfortable in changing out the original membranes. New membranes were installed to improve system performance. Membranes were replaced on a cluster basis (16 at a time) beginning in November 2005, about 11 months after initial start-up. The last cluster received new membranes in August 2006, roughly 20 months after start-up.

When the membranes were replaced, plant performance improved. Membrane feed-gas temperature has stabilized above −1° C. and continues to operate at predicted levels on a regular basis (Fig. 9).

Carigali Hess can only determine cluster-based operating conditions when clusters are operating in the high-pressure permeate mode. When the cluster is in the low-pressure permeate mode, the permeate gas pressure at that specific cluster is insufficient for delivery and analysis by the online gas chromatograph.

Only about one third of the clusters will operate in high-pressure permeate mode; the rest will operate in low-pressure mode. Membranes perform better in low-pressure mode due to the lower backpressure. Measured performance characteristics of the overall plant are therefore better than what has been measured on clusters operating exclusively in the high-pressure permeate mode.

Fig. 10 shows measured membrane performance from a cluster that was loaded with new membranes in December 2005. The data show very little performance declines.

Performance monitoring

Carigali Hess has recently hired NATCO to assist with performance monitoring and measurement of the operating clusters and overall system. This will provide the ability to indicate potential unexpected membrane performance issues or operational anomalies that can be extracted from the measured operating parameters.

The effort to track system performance began in second-quarter 2006 and includes raw data transmitted to NATCO for measuring key performance characteristics. These key characteristics monitored over time will enable NATCO and Carigali Hess to determine performance curves.

These curves can be used for other decisions such as projections for potential membrane use, membrane budget considerations, as well as identifying operating anomalies that may have contributed to reductions in measured performance characteristics.

Also included in this tracking of system performance is an application program residing on a server that Carigali Hess accesses via a secure link through the internet.

This program was developed specifically for CKP and will take current measured performance of the overall plant or on a cluster basis and converge on a solution that matches current measured conditions. These solutions, based on current measured operations, will allow Carigali Hess to better manage its day-to-day operations, including decisions about when it is economical to replace membranes, evaluate which clusters should be in service, determine effects of changing feed gas conditions,

impact of surface area vs. sales gas btu content, etc.

Carigali Hess is currently in the process of doubling capacity of the CKP facility to 870 MMscfd from 425 MMscfd of sales gas. NATCO is providing the additional pretreatment equipment and the CO_2 membranes for this expansion. ✦

The authors

Alan Callison is the general manager of Cynara membrane service and operations for NATCO Group Inc., Houston. He was previously the international services manager for NATCO and an operations and field services manager for Cynara. Before joining NATCO, Callison was a senior production superintendent with Houston Natural Gas Co.

Graham Davidson is currently head of process engineering for Carigali Hess Operating Co., Kuala Lumpur. He has more than 18 years' experience as a lead process engineer in the operation, design, commissioning, and start-up of offshore oil and gas plants and onshore petrochemical plants. For the past 8 years, he has been involved in the design, commissioning, and operation of CO_2 membranes on offshore gas-processing facilities. Davidson holds a degree (1988) in chemical engineering from Monash University, Australia.

Chromatograph, equation yield usable field dewpoint prediction

Todd Dustman
Jeff Drenker
Questar Pipeline Co.
Salt Lake City

David F. Bergman
BP America Inc.
Houston

Jerry A. Bullin
Bryan Research & Engineering Inc.
Bryan, Tex.

Pipelines can use gas-chromatograph analysis in conjunction with an equation of state to predict hydrocarbon dewpoint in the field. This prediction method provides sufficient data resolution to enable pipeline operators to manage receipt and delivery of gas into their systems to meet hydrocarbon dewpoint specifications of downstream customers.

Questar Pipeline Co. monitors its pipeline system in Utah, Wyoming, and Colorado with gas chromatographs and manages the systems based on HDP. Questar used four technicians to conduct a two-phase study on dewpoint at different locations on its pipeline system.

Phase I showed agreement of the dewpoint values from the C_9+ analyses to the extended analyses within expected limits of about 10-12° F. for 95% of the data sets. When compared to dewpoint by chilled mirror, some of the data sets matched within the expected 10-12° F. About a third of the data sets, however, showed chilled-mirror values more than 20° F. greater than GC-EOS values.

Investigation found that the agreement between the chilled mirror and GC-EOS values were within the expected limits of 10-12° F. for Technicians 1 and 2 and that essentially all the values differing more than 20° F. were collected by Technician 4, who was apparently rushed during data collection.

Phase II used a single technician to gather additional data, showing that Peng-Robinson matched the chilled mirror somewhat better than Soave-Redlich-Kwong, but nearly all of the points agreed within 10° F.

Based on a presentation to and updated with new data since the Gas Processors Convention, Mar. 5-7, 2006, Dallas.

Liquid fallout

The issue of liquid hydrocarbon formation in gas transmission lines has preoccupied the gas industry for several years. Fluctuating processing spreads (the price difference between equivalent quantities of natural gas and NGL) since 2003 have often led processing plant operators to minimize hydrocarbon liquid recoveries and enhance gas production, increasing the dewpoint of gas delivered to downstream pipelines. Deliveries of high-hydrocarbon-dewpoint gas into pipelines increase the likelihood of hydrocarbon liquid fallout, leading to concerns for both pipeline operators and their customers.

These concerns prompted formation of an industry-wide taskforce that published its findings in a white paper.[1] The US Federal Energy Regulatory Commission issued a policy statement in June 2006 providing guidance to pipeline companies on how to address these gas-quality issues. Recommendations from the document formed much of the technical basis of the policy statement.

One of the key recommendations from the white paper was that a pipeline company should include a control parameter in its tariffs allowing it to limit deliveries of gas that could cause formation of liquid hydrocarbons. The white paper recommended that pipelines use cricondentherm hydrocarbon dewpoint as the control parameter because it "offered the greatest operational flexibility for all stakeholders."

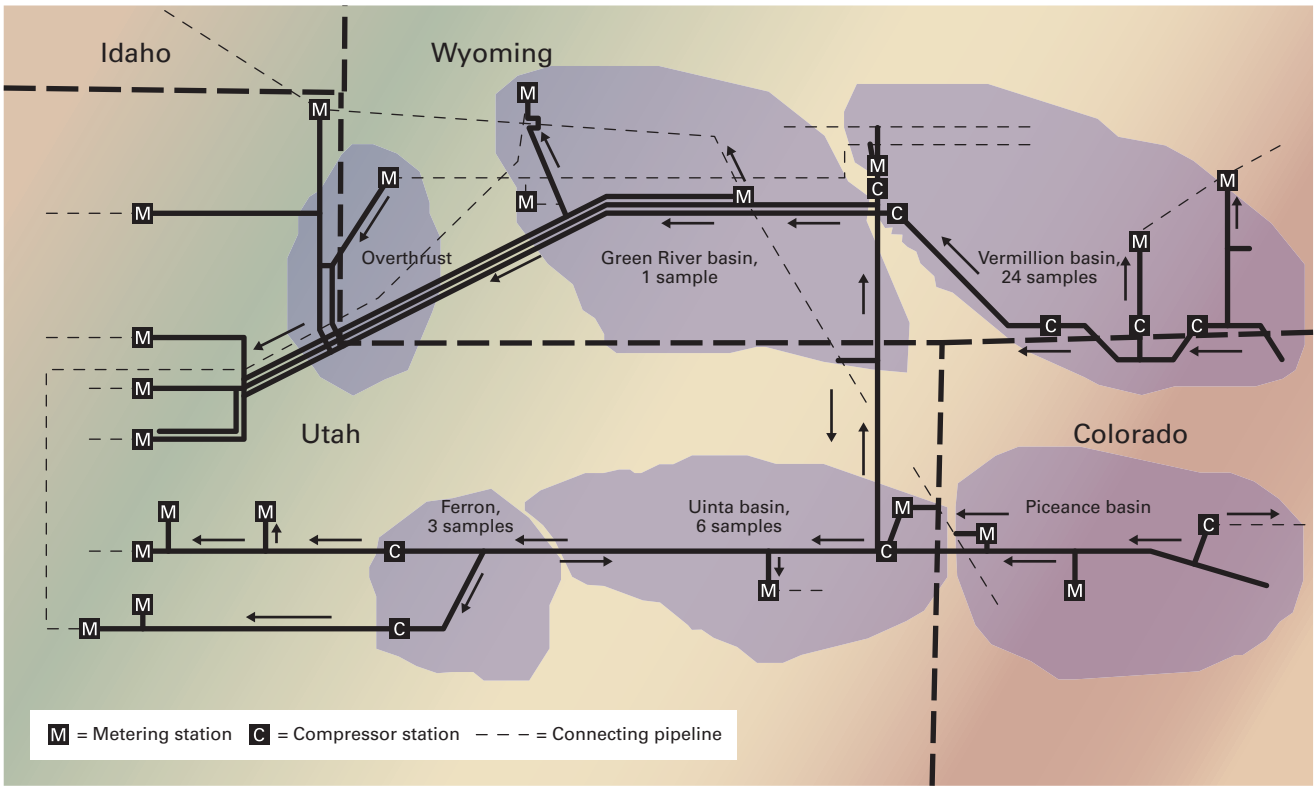
This recommendation stimulated renewed interest in dewpoint determination methods and their relative accuracies.

The theoretical dewpoint consists of any point along the dewpoint line moving from gas phase to the first small drop of liquid. The cricondentherm, or CHDP, is the maximum temperature at which hydrocarbon liquids could occur (maximum dewpoint).

This article presents a description of

QUESTAR SYSTEM, SAMPLING LOCATIONS

Fig. 1



Questar Pipeline Co.'s use of dewpoint determination to manage liquid fallout on its system and deliver spec gas to downstream pipelines. It compares an evaluation of dewpoint using the chilled-mirror method to compositional analysis by gas chromatograph combined with an equation of state.

A C_9+ analysis and an extended analysis yielded two compositional analyses. Redistributing the data from the C_9+ analysis provided a third composition a (modified C_6+ characterization). Field-derived gas samples from actual producing sources provided the basis for the dewpoint evaluation.

Determining dewpoints

Common methods used to determine hydrocarbon dewpoint consist of direct measurement using a chilled-mirror instrument and indirect measurement using compositional analysis from a gas chromatograph combined with an EOS. Drenker and others present an excellent review and discussion of these methods.[1-8]

The chilled-mirror method flows a gas stream past a mirror that is being cooled or chilled.[9] The temperature at which the first condensation or dew appears on the mirror provides the dewpoint. The operator must not mistake the condensation of other substances (e.g., glycol and water) for hydrocarbon condensation.

The GC-EOS method uses a gas chromatograph for compositional analysis in conjunction with an equation of state to calculate the dewpoint as well as the cricondentherm and phase envelope. The accuracy of the method depends largely on determining the C_6+ components, typically through one of two methods. The first involves a standard GC analysis for composition through C_6+, using GPA 2261 procedure[10] with a procedure to characterize the C_6+ fractions suggested by Moshfeghian (OGJ, Nov. 21, 2005, p. 60), Voulgaris,[7] and Daniels.[11]

The second method for C_6+ determination uses either a C_9+ analysis or an extended analysis of components from a GC using GPA 2286 procedures.[12] Cal-

CG-EOS, CHILLED MIRROR HDP COMPARISON

Table 1

Gas	Average chilled mirror HDP, °F.	ProMax-PR HDP, °F.	Differential	ProMax-SRK HDP, °F.	Differential
A	46	44	–2	47	+1
B	71	69	–2	72	+1
C	61	58	–3	62	+1
E	64	58	–6	62	–2
F	71	69	–2	72	+1
			Average, –3.0		Average, +0.4

culations typically use either a Peng-Robinson or Soave-Redlich-Kwong EOS. This article used ProMax process simulation software by Bryan Research & Engineering, Inc. for all calculations.[13]

GC-EOS confirmation

Warner used five certified gas standards for measurement of the dewpoint by the chilled-mirror method.[3] Weight, rather than GC, determines the composition of a certified gas standard. Warner did not report the compositions for these five certified gas standards and did not use them to calculate the dewpoint by the GC-EOS method.

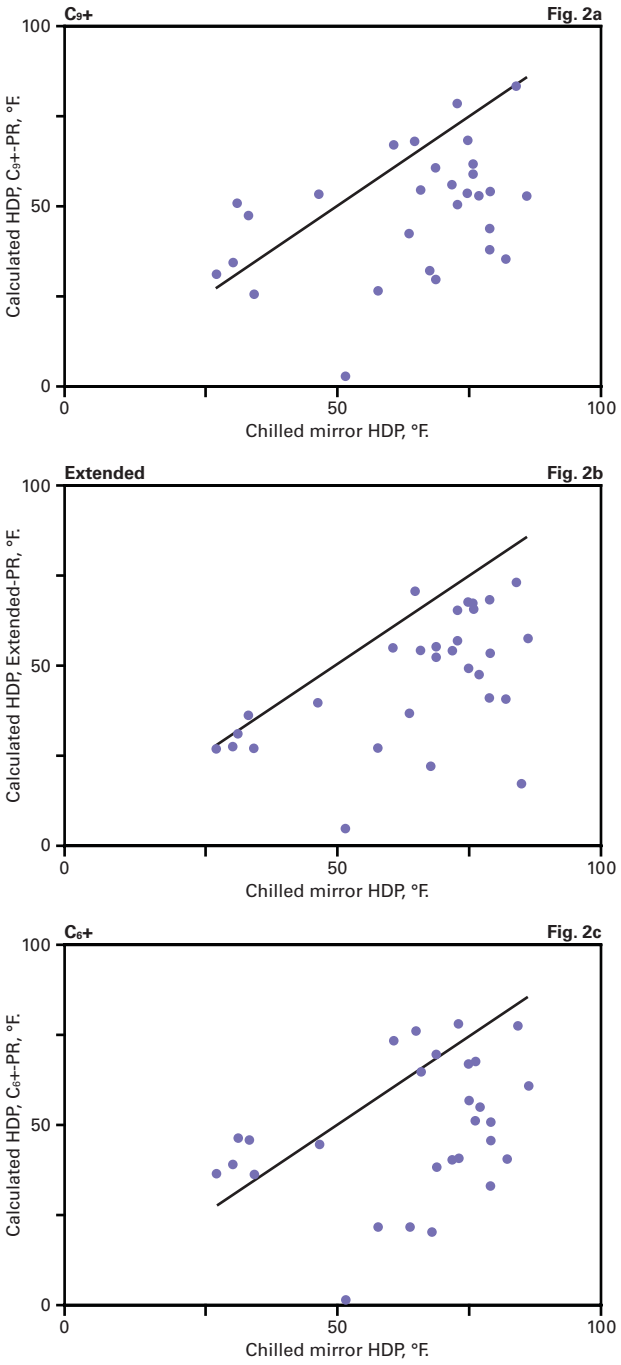
This article used the compositions of the five certified gases obtained from Hal Warner[14] and ProMax to calculate dewpoint.

Table 1 shows that dewpoint calculated by both PR and SRK agree well with measurements by chilled mirror. The average difference for each in ProMax was −3.0 and 0.4° F., respectively. With good compositional analyses, therefore, the PR and SRK EOS options in ProMax predict dewpoint within the accuracy of the chilled-mirror method.

Based on this limited set of observations, SRK predicts dewpoint 3-4° F. higher than PR and matches the chilled-mirror measurements somewhat more closely.

HDP COMPARISONS, PHASE I

Fig. 2



Questar pipeline

Fig. 1 shows a map of Questar's pipeline system with interconnected producing basins. The temperature-sensitive distribution loads on the west end of the system can cause gas flows to vary greatly. It is not uncommon to see several null points at any given time on the system.

Questar's system also differs from traditional interstate pipeline systems in that portions of the system are designed and operated to handle natural gas saturated with hydrocarbon liquids. Questar installed liquid-handling facilities (pig launchers, receivers, and slug catchers) on its system, along with processing plants, to allow it to receive high-hydrocarbon-dewpoint gas and deliver processed gas to downstream markets with established hydrocarbon-dewpoint specifications.

Dewpoint management

Questar's ability to meet dewpoint specifications depends largely on operating its straddle processing plants and is based on monitoring and managing the dewpoint of the gas that enters its pipeline system. Questar developed an online GC-EOS system to calculate dewpoint temperatures and cricondentherms automatically at various points throughout its pipelines. Questar's fleet of chromatographs analyzes through C_9+, as opposed to the industry-standard C_6+.

Measured composition from the chromatographs moves to nearby flow computers where the data are stored and transmitted to Questar's gas-control server in Salt Lake City. The compositions then feed into a dedicated server to calculate dewpoint temperatures at pipeline pressure along with cricondentherms. ProMax calculates both values. Hydrocarbon-dewpoint values are updated once every 2 min for 271 individual sample points on the system. Questar's supervisory control and data acquisition system provides dewpoint data to its gas control and operating personnel.

Questar's gas control and field operations monitor dewpoint data closely to help set pig launching intervals for removal of free liquids in the pipe and to help maintain the correct dewpoint temperature to downstream pipelines.

Data from the dewpoint calculation system identify points with the highest dewpoint temperatures, allowing curtailment of high-hydrocarbon-dewpoint gas.

Questar's engineers and operations personnel use the archived data to design new facilities and optimize operation of the system.

Analysis methodology

To assess the relative accuracy of the different methods of determining dewpoint, Questar conducted tests to determine the dewpoint of gas received into its system from a number of fields, using four different methods for each data set:

- Direct measurement using a chilled-mirror apparatus.
- Indirect measurement using Questar's standard C_9+ analysis and an EOS.
- Indirect measurement using an extended analysis and an EOS.
- Indirect measurement using a modified C_6+ characterization and an EOS.

This modified C_6+ characterization used the chromatograph results from the second of these methods, lumping all C_6+ components together, and redistributing them, assuming 47% C_6, 36% C_7, and 17% C_8 molar composition as recommended by Daniels.[11]

All gas-chromatograph measurements met GPA 2186-95 accuracy standards.

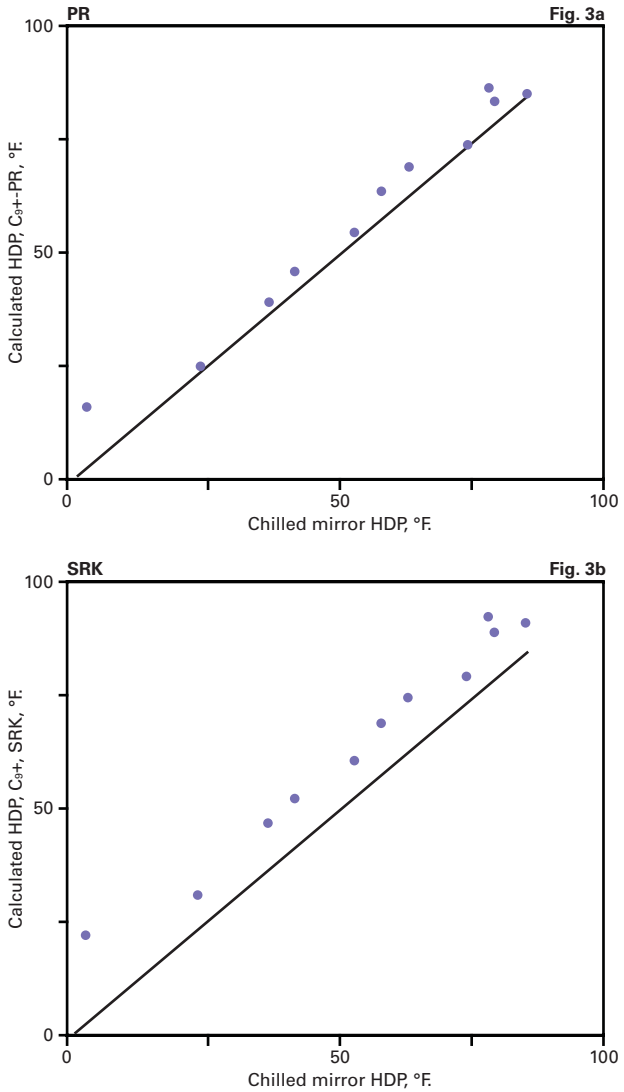
Measurement of the water content of the gas, along with the temperature and pressure, determined water dewpoint for each data set.

Direct measurement

Each sample location on the pipeline network saw a sample line heated to 120-140° F. and connected to a Chandler Bureau of Mines dewpoint tester. CO_2 chilled the mirror of the field apparatus. Four technicians used different chilled-mirror devices to measure according to ASTM D1142 procedures.

This procedure works relatively well in most cases. On very dry gases, however, the dewpoint tester could not chill below –40° F. Calculated dewpoints for some samples lay significantly below the –40° F. obtained with the chilled-mirror apparatus. The difference between a hydrocarbon dewpoint, water dewpoint, or some other compound (e.g., glycol or compressor lube oil) forming a film on the chilled mirror proved difficult to determine.

HDP COMPARISONS, PHASE II Fig. 3



Chromatographic analysis

The C_9+ analysis groups the C_6, C_7, C_8, and C_9 by summing the area of the peaks and assigning a response factor based on the normal isomer. The on site gas analysis, which is the Questar standard C_9+ analysis, used a Varian 4900 micro gas chromatograph and was performed in the field along with the chilled-mirror measurements. Technicians heated the sample delivery system to the chromatograph and the chilled mirror to 120-140° F.

Four different technicians using the same model GC performed the analyses. Each of the four Varian GCs used an 8-m capillary column and a 0.4-m Haysep A column.

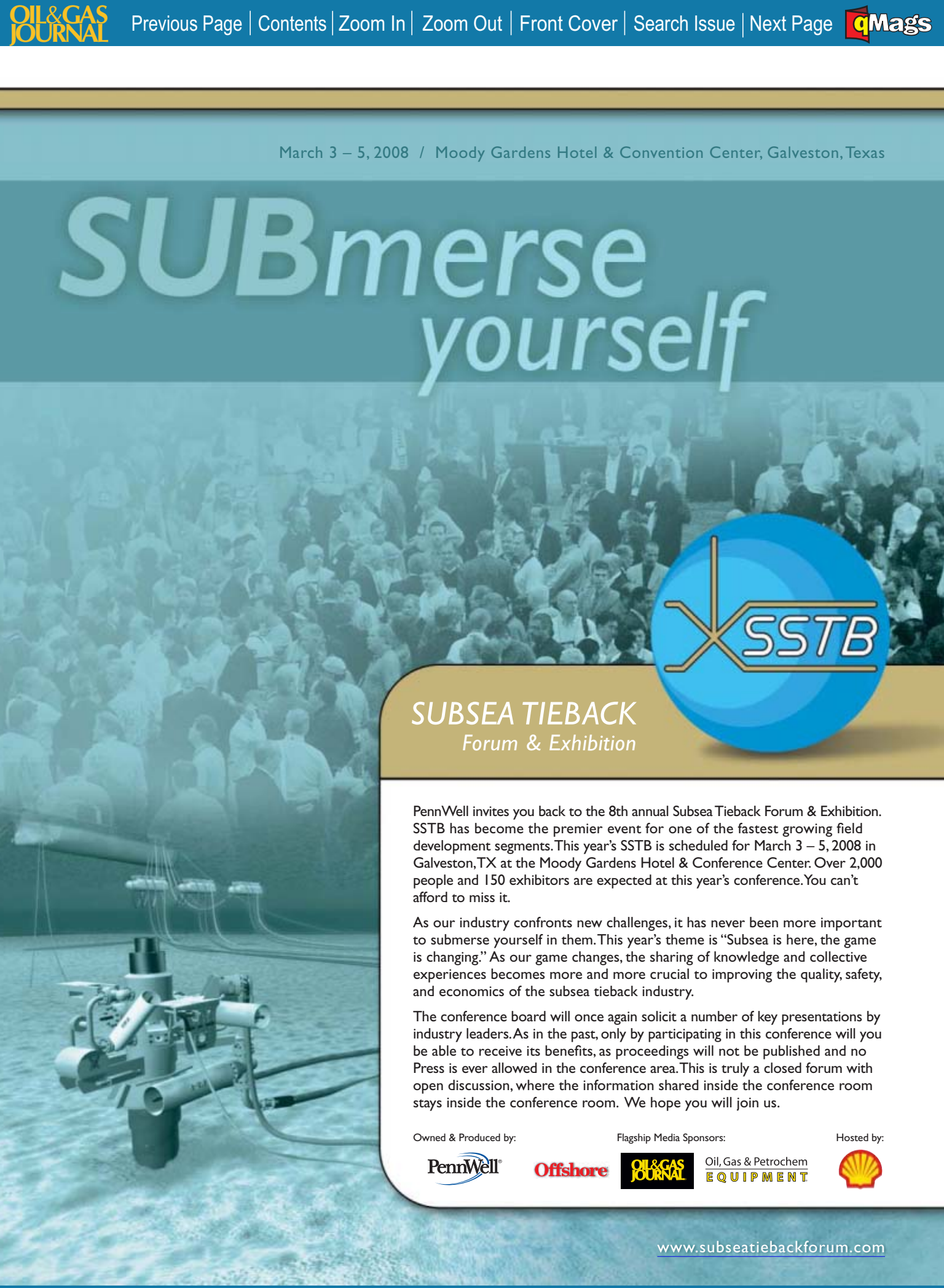
Extended analysis

The extended analysis quantified a broader range of components, especially the heavier components. Questar reported BTEX (benzene, toluene, ethylbenzene, and xylene) and n-hexane along with several other compounds. It grouped other compounds in a similar manner to the C_9+ analysis.

API's 14.1 purge-and-fill method obtained spot samples in the field for extended analysis. A heated box maintained the sample cylinder at 120-140° F. until it was removed and insulated with a preheated wrap. A 36-in. extension tube kept the Joule-Thomson cooling away from the cylinder on the exit throttling device. A truck with a heated enclosure brought the cylinder back to the lab, where a heated room maintained the cylinder's temperature at 120° F. Extended analysis used an HP6890 chromatograph with the Wasson configuration and a 60-m capillary column with a flame ionization detector.

March 3 – 5, 2008 / Moody Gardens Hotel & Convention Center, Galveston, Texas

SUBmerse yourself



SUBSEA TIEBACK
Forum & Exhibition

SSTB

PennWell invites you back to the 8th annual Subsea Tieback Forum & Exhibition. SSTB has become the premier event for one of the fastest growing field development segments. This year's SSTB is scheduled for March 3 – 5, 2008 in Galveston, TX at the Moody Gardens Hotel & Conference Center. Over 2,000 people and 150 exhibitors are expected at this year's conference. You can't afford to miss it.

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

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

Owned & Produced by: PennWell

Flagship Media Sponsors: Offshore | OIL&GAS JOURNAL | Oil, Gas & Petrochem EQUIPMENT

Hosted by:

www.subseatiebackforum.com

Results

Phase 1 of this study included 34 data sets. Analysis of these results led to Phase 2, consisting of 11 data sets. Each data set included the field, sample location, pipeline pressure, water dewpoint, and various hydrocarbon dewpoints. Collecting the data for this study under typical operating conditions undoubtedly introduced more variability into the analysis but should also reflect actual pipeline conditions.

Phase 1 included five data sets with hydrocarbon dewpoints near or below the water dewpoint. Three of these five originated in the Ferron field and were apparently near or below the cooling limit of –40° F. for the chilled-mirror device. The dewpoints from both the C_9+ and extended analyses also lay far below the chilled-mirror value.

The cooling limit for the chilled-mirror device or the water dewpoint appeared to interfere with the measurement of hydrocarbon dewpoint by chilled mirror for these five data sets, prompting their omission from further analysis and discussion.

Comparison of dewpoint from the C_9+ analyses and the extented analyses showed about 80% of the values within 10° F. and 95% within about 12° F. for both PR and SRK. This is excellent agreement, given that the C_9+ analyses were performed on site at the sample locations by four different technicians using different versions of the same Varian GC. An HP chromatograh collected, transported to the central laboratory, and analyzed the samples used in the extended analysis.

Phase 1 compared the dewpoint values from the chilled-mirror method to the values from each of the GC methods using PR (Fig. 2). The GC-SRK combination reached virtually the same results but with dewpoints 3-4° F. higher than for PR.

Roughly 30-40% of the data sets showed chilled-mirror values more than 20° F. greater than GC-EOS values. A field study such as this typically shows agreement within 10-12° F. But the excellent agreement between the C_9+ and extended analyses lends credibility to the values calculated by GC-EOS.

A detailed investigation discovered differences between the samples collected by each technician. Of the 29 data sets used, Technicians 1 and 2 collected 9 sets and Technician 4 collected 20 sets. Samples collected by Technicians 1 and 2 showed agreement between the chilled mirror and GC-EOS within the expected limits of about 10-12° F., depending on the GC-EOS combination, for nearly all values, with only one greater than 20° F for certain GC-EOS combinations.

The extended analysis, as expected, gave slightly better results than the C_9+, while the C_6+ characterization was not as good for Technicians 1 and 2.

Agreement between chilled mirror and the GC-EOS values for Technician 4 were within the expected limit for only four to six sets, depending on GC-EOS combination, with about half differing by more than 20° F. Technican 4 collected data for 6 days; three sets were collected each day for 2 days, and four sets were collected each day for 4 days. The technician measured the hydrocarbon dewpoint for each sample by chilled mirror, ran the C_9+ GC analysis in the field, and collected a gas sample for the extended GC analysis.

Technician 4 appears to have rushed and probably did not take adequate time performing the chilled-mirror measurement.

Phase II

The data problems in Phase I called about 60% of the data into question, prompting Questar to add Phase II and collect samples from 11 additional locations to supplement the original data. Technician 1 collected all the new samples from the Uinta basin, taking a chilled-mirror measurement and conducting a C_9+ gas analysis.

Fig. 3 shows the results from Phase II for PR and SRK. The supplemental data showed that operator error was indeed the major cause of deviation in Phase I. The data also demonstrated the efficacy of using GC data along with an EOS to predict hydrocarbon dewpoint and CHDP in a field setting.

PR matched the data in Phase II slightly better than SRK. Out of the 11 samples taken, all but 1 were within 10° F. or less of the chilled mirror, with more than half the values within 5° F.

SRK slightly overestimated the hydrocarbon dewpoints but were still generally within an acceptable range generally.

Finding that SRK was a better predictor of hydrocarbon dewpoint using the five certified gas samples from Warner[3], and that PR was the better predictor on the Uinta Basin samples, initially surprised the researchers. The entirely different nature of the samples, however, suggests that pipelines should not be limited to just one EOS for calculation purposes but rather should select one or several equations that best predict hydrocarbon dewpoint temperatures for the particular gas supplies in their systems. Both PR and SRK agreed with the chilled-mirror method in this case within acceptable limits, showing both the viability of GC-EOS methodology and the care that needs to be taken when applying it.

Acknowledgments

The authors acknowledge the help of Lili Lyddon and John Polasek of Bryan Research & Engineering, Inc. in completing this article. The authors also acknowledge Andrew Tomich and his staff at Questar Applied Technology Services for their help in collecting and preparing gas samples, performing the chromatographic analytical work, and taking the chilled-mirror dewpoint measurements used in this article. ✦

References

1. "White Paper on Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure," Natural Gas Council for the Federal Energy Regulatory Commission, NGC+ Liquid Hydrocarbon Drop Out Task Group, Feb. 28, 2005.

2. Bergman, D.F., Tek, M.R., and Katz, D.L., Retrograde Condensation in Natural Gas Pipelines, Arlington, Va.:

American Gas Association, 1975.

3. Warner, Jr., H.R., Leamer, E.E., Spence, A.P., Bone, R.L., Hubbard, R.A., Bernos, J., and Kriel, W.A., "Hydrocarbon Dew Point Determination of Lean Natural Gases," 80th Annual Convention of the Gas Processors Association, San Antonio, March 2001.

4. "Gas Quality, Hydrocarbon Dew Point (HDP), Interchangeability," Gas Processors Association Federal Subcommittee Issue Brief-Gas Quality, PL04-3, Feb. 3, 2005.

5. Fatica, Al, "Gas-quality Debate Heats Up as More US LNG Imports Loom," OGJ, June 14, 2004, p. 6.

6. Ernest, Kevin, and Pettigrew, Douglas, "Hydrocarbon Dew Point Monitoring of Natural Gas Using Field-Mounted, On-line Gas Chromatographs," Pipeline & Gas Journal, July 2005.

7. Voulgaris, M.E., Peters, C.J., De Swan Arons, J., Derks, P.A., Janssen, R., and Smit, A.L.C., "Prediction of the Potential Hydrocarbon Liquid Content of Lean Natural Gas Comparison with Field Tests," 73rd Gas Processors Association Annual Convention, New Orleans, Mar. 7-9, 1994.

8. Drenker, Jeff, Dustman, T., Bergman, D.F., and Bullin, J.A., "An Analysis and Prediction of Hydrocarbon Dew Points and Liquids in Gas Transmission Lines," 85th Gas Processors Association Annual Convention, Grapevine, Tex., Mar. 5-8, 2006.

9. ASTM D1142-95, "Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew Point Temperature," 2000.

10. GPA 2261, "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Tulsa: Gas Processors Association, 2000.

11. Daniels, a Division of Emerson Electric, Standard configurations programmed into Daniels Chromatographs.

12. GPA 2286, "Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography," Tulsa: Gas Processors Association, 1995.

13. ProMax Version 1.2, Process Simulation Software by Bryan Research & Engineering, Inc., Bryan, Tex., 2005.

14. Warner, Hal, private communication, Jan. 14 and Jan. 21, 2006.

The authors

Todd Dustman (todd.dustman@questar.com) is director of system operations analysis at Questar Pipeline Co. He has 26 years' experience in the natural gas industry, including its pipeline, distribution, gathering, exploration, and production segments. He holds a BS (1980) in industrial engineering from the University of Utah. Dustman served on both the HDP and Interchangeability NGC+ FERC White Paper task groups.

Jeff Drenker (jeff.drenker@questar.com) is a senior system engineer at Questar Pipeline Co. Prior to joining Questar, Drenker served as a process engineer for consulting companies specializing in coal beneficiation. He holds a BSME (1974) from the University of Idaho. He is a member of American Society of Mechanical Engineers and is a registered professional engineer in Utah.

David F. Bergman (david.bergman@bp.com) is a PVT fluid consultant at BP America, in Houston. He originally worked with Amoco conducting laboratory studies. He holds a BS ChE (1970) from Michigan Technological University and MS (1971) and PhD (1976) in chemical engineering from the University of Michigan. Bergman is a member of SPE and Gas Processors Association where he is chairman of "Section F, Technical Data Development."

Jerry A. Bullin (j.bullin@bre.com) is president of Bryan Research & Engineering Inc., Bryan, Tex. He has also served as a process engineer at BS&B Process Systems and Jefferson Chemical Co. He is professor emeritus of chemical engineering at Texas A&M University. He holds BS, MS, and PhD degrees in chemical engineering from the University of Houston and is a member of American Institute of Chemical Engineers, Gas Processors Association, and American Chemical Society.

Equipment/Software/Literature

Pneumatic actuator has aluminum body

This new Apollo-brand pneumatic actuator has an extruded aluminum body and twin rack and pinion design that delivers constant torque output of over 500,000 cycles or more.

The new actuators are matched to the operation of the firm's ball valves and butterfly valves. They also feature inboard and outboard travel stops for easy stroke adjustment to virtually any host valve's open or closed positions.

Actuators are designed for petrochemical operations.

Units are built for long, dependable service, the company says. The body is hard-coat anodized to resist wear and corrosion. Bore finishing helps minimize friction and wear.

Nickel-plated steel pinions resist internal and external corrosion.

Other long-life features include stainless steel assembling screws and die cast aluminum end caps and pistons. Actuators are prelubricated at the plant for the life of the assembled unit.

Source: **Conbraco Industries Inc.**, Box 247, Matthews, NC 28106.

New system purges pipe, vessels quickly

Large pipe and vessels can be purged of air quickly and easily with the Argweld quick purge system.

The system typically purges a 914 mm diameter pipe to below 0.1% oxygen in less than 10 min, with faster purging for smaller pipe sizes, the company says.

Savings in time and purge gas consumption are achieved by reducing the volume purged, the company points out. Two inflatable dams are positioned inside the pipe, restricting the length of the purged section to about 75 mm on each side of the weld. At the same time, a sleeve joining the dams occupies most of the pipe's diameter, so that only the space between the outer surface of the sleeve and the inner surface of the pipe needs to be purged.

When the Argweld has been positioned inside the pipe, by using pull tags, it is inflated by the inert gas supply so that each end dam forms a seal. Once the dams are fully inflated, the pressure opens a valve to allow the inert gas to enter the space between the sleeve and the pipe to displace the air.

Welding can begin as soon as the oxygen level is low enough.

Source: **Huntingdon Fusion Techniques Ltd.**, Stukeley Meadow, Bwscwm Rd., Burry Port, Carmarthenshire, Wales SA16 0BU.

Services/Suppliers

Chadbourne & Parke LLP

New York, has announced the opening of an office in Dubai to provide a hub for the firm's expanding energy/project finance and cross-border acquisition practices.

Jack Greenwald, a Chadbourne partner who has practiced law in Dubai since 1986, will head the Dubai office.

The firm's client activities in the region have involved capital markets, privatizations, private placements, joint ventures, oil gas and petrochemical projects, and other infrastructure projects, as well as international arbitration.

Chadbourne & Parke LLP is a multinational law partnership, first established in 1902.

GE Oil & Gas

Houston, has acquired the assets of the former Preco service center from GE Energy. The center is totally dedicated to the oil and gas sector, and offers a broad range of support activities throughout North and South America. All makes and sizes of turbomachinery are served by the center, which employs approximately 100 people.

GE Oil & Gas is a world leader in advanced technology products and services, operating in all segments of the global oil and gas industry. Based in Florence, Italy, the company offers solutions for production, LNG, transportation, storage, refineries, petrochemicals, and distribution systems, as well as pipeline integrity solutions.

Verano Inc.

Mansfield, Mass., has announced its company name change to Industrial Defender Inc., adopting the name of its flagship product. This re-branding culminates nearly 20 years of experience in protecting critical infrastructure systems in the power, water, energy, transportation, and chemical industries.

Industrial Defender Inc. is the first company to offer a completely integrated cyber security solution designed to protect the real-time process control and SCADA environment in a flexible and cost effective platform. The company has more than 1,100 global deployments in securing critical infrastructure systems, and more than 3,000 mission critical SCADA deployments.

Cameron

Houston, has elected John C. Bartos as vice-president, development and technology.

Bartos joined Cameron in 2000, and most recently served as vice-president of engineering and product development for the compression systems group. He holds a bachelor of engineering degree from Stevens Institute of Technology, Hoboken, NJ, and worked for Ingersoll-Rand and A-C Compressor prior to joining Cameron.

Cameron is a leading provider of flow equipment products, systems, and services to the worldwide oil, gas, and process industries.

Today's (*and tomorrow's*)

Industry Leaders Rely on OGJ

Oil & Gas Journal - The Industry Authority for more than a century

Exploration • Development • Drilling • Production • Processing • Transportation

Keep Your Career on Track

SUBSCRIBE TODAY!

Every week, Oil & Gas Journal delivers concise, insightful reports on issues affecting the global petroleum industry - precisely the kind of information you need to keep your competitive edge.

Tens of thousands of industry professionals routinely turn to Oil & Gas Journal for the latest news, technology advances, and down-to-earth analysis of oil and gas developments throughout the world. No other publication provides such comprehensive and timely information.

Subscribing to Oil & Gas Journal could easily be the best career investment you'll ever make.

To subscribe, go to:
www.BuyOGJ5.com

Or for more information on Oil & Gas Journal, go to:
www.ogjonline.com

What Subscribers Say

Extracted from a recent survey[1], the following are verbatim responses to, "Tell us how useful Oil & Gas Journal is to you and how you use it in your job."

"Great resource to stay on top of recent industry news and trends."

"Extremely useful. Of all trade publications, this is the one we rely on."

"Oil & Gas Journal is my connection to the industry."

"I would not be without it!"

PennWell®

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

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	5-18 2007	[1]5-11 2007	5-18 2007	[1]5-11 2007	5-18 2007	[1]5-11 2007	5-19 2006
	1,000 b/d						
Total motor gasoline	426	455	46	21	472	476	409
Mo. gas. blending comp.	622	788	45	96	667	884	1,163
Distillate[2]	212	216	49	58	261	274	399
Residual	201	273	37	43	238	316	375
Jet fuel-kerosine	85	8	97	179	182	187	320
LPG	217	304	5	4	222	308	259
Unfinished oils	863	474	25	12	888	486	622
Other	296	865	3	58	299	923	637
Total products	**2,922**	**3,383**	**307**	**471**	**3,229**	**3,854**	**4,184**
Canadian crude	1,285	1,259	211	288	1,496	1,547	1,849
Other foreign	7,750	7,499	1,324	876	9,074	8,375	2,416
Total crude	**9,035**	**8,758**	**1,535**	**1,164**	**10,570**	**9,922**	**9,265**
Total imports	**11,957**	**12,141**	**1,842**	**1,635**	**13,799**	**13,776**	**13,449**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—MAY 18, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMBtu					
Barcelona	6.79	4.83	6.02	4.74	5.39	6.00
Everett	6.63	4.66	6.26	4.76	5.15	6.92
Isle of Grain	3.59	1.47	3.02	1.36	2.13	3.09
Lake Charles	5.55	3.55	5.30	3.71	4.02	6.15
Sodegaura	4.47	6.48	4.68	6.20	5.58	3.98
Zeebrugge	5.63	3.54	5.05	3.45	4.12	5.07

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel Kerosine	Fuel oils		Unfinished oils
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PAD I	15,455	51,375	23,434	10,550	41,357	14,861	7,126
PAD II	74,706	47,198	15,857	7,622	28,487	1,135	13,802
PAD III	187,136	64,495	27,080	12,815	33,484	16,928	46,701
PAD IV	13,571	6,005	1,905	612	3,266	298	2,749
PAD V	[1]58,092	30,030	20,532	9,559	12,946	5,504	23,064
May 18, 2007	**[1]348,960**	**199,103**	**88,808**	**41,158**	**119,540**	**38,726**	**93,442**
May 11, 2007[3]	**349,935**	**201,448**	**90,057**	**39,518**	**120,376**	**38,747**	**94,089**
May 19, 2006	**342,627**	**209,752**	**91,298**	**39,230**	**117,318**	**41,709**	**92,792**

[1]Included in total motor gasoline. [2]Includes 67.235 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAY 18, 2007

District	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,287	1,422	1,440	1,618	89.0	1,781	81	563	182
App. Dist. 1	95	74	84	95	88.4	75	0	22	2
Dist. 1 total	**3,382**	**1,496**	**1,524**	**1,713**	**89.0**	**1,856**	**81**	**585**	**184**
Ind., Ill., Ky.	2,252	2,050	2,068	2,355	87.8	1,233	88	583	30
Minn., Wis., Dak.	412	388	401	442	90.7	352	27	123	10
Okla., Kan., Mo.	841	673	694	786	88.3	565	19	282	5
Dist. 2 total	**3,505**	**3,111**	**3,163**	**3,583**	**88.3**	**2,150**	**134**	**988**	**45**
Inland Texas	939	590	608	647	94.0	398	40	164	7
Texas Gulf Coast	4,042	3,272	3,385	4,031	84.0	1,356	370	901	153
La. Gulf Coast	3,471	3,262	3,267	3,264	100.1	1,393	383	838	70
N. La. and Ark.	227	173	191	215	88.8	67	7	46	8
New Mexico	159	102	102	113	90.3	116	2	39	0
Dist. 3 total	**8,838**	**7,399**	**7,553**	**8,270**	**91.3**	**3,330**	**802**	**1,988**	**238**
Dist. 4 total	**661**	**493**	**507**	**596**	**85.1**	**241**	**29**	**144**	**13**
Dist. 5 total	**2,896**	**2,503**	**2,739**	**3,173**	**86.3**	**1,574**	**428**	**560**	**185**
May 18, 2007	**19,282**	**15,002**	**15,486**	**17,335**	**89.3**	**9,151**	**1,474**	**4,265**	**665**
May 11, 2007*	**18,747**	**14,953**	**15,321**	**17,335**	**88.4**	**8,881**	**1,448**	**4,145**	**634**
May 19, 2006	**16,564**	**15,098**	**15,422**	**17,115**	**90.1**	**8,563**	**1,349**	**4,105**	**573**

*Revised.
Source: American Petroleum Institute.
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

	*5-18-07	*5-19-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	90.64	81.69	8.95	11.0
Brent crude	67.94	67.95	–0.01	0.0
Crack spread	22.71	13.74	8.96	65.2
FUTURES MARKET PRICES				
One month				
Product value	91.23	83.50	7.73	9.3
Light sweet crude	63.60	69.12	–5.52	–8.0
Crack spread	27.63	14.38	13.25	92.2
Six month				
Product value	81.98	81.02	0.95	1.2
Light sweet crude	68.05	72.62	–4.57	–6.3
Crack spread	13.92	8.41	5.52	65.6

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

OGJ GASOLINE PRICES

	Price ex tax 5-16-07	Pump price* 5-16-07	Pump price 5-17-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	262.9	302.6	289.4
Baltimore	262.6	304.5	296.3
Boston	254.4	296.3	290.2
Buffalo	248.6	308.7	300.2
Miami	267.2	317.5	303.3
Newark	252.8	285.7	288.0
New York	246.4	306.5	301.9
Norfolk	254.9	292.5	291.5
Philadelphia	256.1	306.8	304.1
Pittsburgh	244.8	295.5	289.4
Wash., DC	271.5	309.9	309.1
PAD I avg.	256.6	302.4	296.7
Chicago	295.0	345.9	319.3
Cleveland	257.5	303.9	282.8
Des Moines	260.4	300.8	269.2
Detroit	260.8	310.0	285.5
Indianapolis	266.6	311.6	279.3
Kansas City	261.5	297.5	267.2
Louisville	271.3	308.2	284.8
Memphis	248.4	288.2	281.4
Milwaukee	270.6	321.9	294.2
Minn.-St. Paul	263.0	303.4	276.4
Oklahoma City	262.2	297.6	267.3
Omaha	259.8	306.2	282.1
St. Louis	261.3	297.3	270.4
Tulsa	261.9	297.3	267.4
Wichita	256.4	299.8	268.3
PAD II avg.	263.8	306.0	279.7
Albuquerque	271.3	307.7	287.7
Birmingham	252.8	291.5	279.9
Dallas-Fort Worth	256.7	295.1	297.7
Houston	254.1	292.5	292.6
Little Rock	250.6	290.8	275.1
New Orleans	250.6	289.0	283.8
San Antonio	241.9	280.3	274.9
PAD III avg.	254.0	292.4	284.5
Cheyenne	259.9	292.3	259.6
Denver	270.4	310.8	275.8
Salt Lake City	262.1	305.0	280.8
PAD IV avg.	264.1	302.7	272.1
Los Angeles	287.1	345.6	334.4
Phoenix	271.1	308.5	306.8
Portland	288.7	332.0	300.7
San Diego	295.7	354.2	341.4
San Francisco	312.9	371.4	339.4
Seattle	286.3	338.7	317.6
PAD V avg.	290.3	341.7	323.4
Week's avg.	**264.1**	**307.7**	**290.7**
Apr. avg.	**234.7**	**278.3**	**270.5**
Mar. avg.	**210.4**	**254.0**	**235.4**
2007 to date	**210.2**	**253.8**	—
2006 to date	**205.1**	**247.9**	—

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

REFINED PRODUCT PRICES

	5-11-07 ¢/gal		5-11-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	232.60	New York Harbor	188.61
Gulf Coast	236.10	Gulf Coast	189.23
Los Angeles	260.85	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	216.57	ARA	188.81
Singapore	212.52	Singapore	190.36
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	244.60	New York Harbor	125.67
Gulf Coast	244.60	Gulf Coast	129.17
Los Angeles	268.60	Los Angeles	156.42
		ARA	114.77
		Singapore	127.04

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

BAKER HUGHES RIG COUNT

	5-18-07	5-19-06
Alabama	4	5
Alaska	7	9
Arkansas	45	21
California	32	36
Land	31	29
Offshore	1	7
Colorado	110	92
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	14	7
Kentucky	7	6
Louisiana	177	199
N. Land	56	60
S. Inland waters	28	18
S. Land	30	38
Offshore	63	83
Maryland	0	0
Michigan	1	3
Mississippi	12	7
Montana	20	23
Nebraska	0	0
New Mexico	79	101
New York	5	6
North Dakota	33	29
Ohio	13	6
Oklahoma	182	177
Pennsylvania	14	17
South Dakota	2	1
Texas	830	735
Offshore	11	13
Inland waters	1	4
Dist. 1	19	21
Dist. 2	25	27
Dist. 3	60	65
Dist. 4	95	83
Dist. 5	174	135
Dist. 6	122	98
Dist. 7B	39	40
Dist. 7C	54	36
Dist. 8	118	86
Dist. 8A	24	28
Dist. 9	34	29
Dist. 10	54	70
Utah	41	36
West Virginia	34	25
Wyoming	71	96
Others—NV-2; TN-4; VA-3	9	2
Total US	**1,744**	**1,639**
Total Canada	**121**	**267**
Grand total	**1,865**	**1,906**
Oil rigs	276	260
Gas rigs	1,466	1,378
Total offshore	75	103
Total cum. avg. YTD	**1,738**	**1,553**

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	5-18-07 Rig count	5-18-07 Percent footage*	5-19-06 Rig count	5-19-06 Percent footage*
0-2,500	56	8.9	56	1.7
2,501-5,000	107	51.4	89	44.9
5,001-7,500	230	18.2	226	19.0
7,501-10,000	418	3.1	373	3.4
10,001-12,500	440	3.1	372	3.2
12,501-15,000	269	0.7	278	0.3
15,001-17,500	100	1.0	110	0.9
17,501-20,000	79	—	73	—
20,001-over	37	—	24	—
Total	**1,736**	**7.6**	**1,601**	**6.9**
INLAND	43		41	
LAND	1,628		1,485	
OFFSHORE	65		75	

*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]5-18-07	[2]5-19-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	20
Alaska	790	801
California	673	689
Colorado	51	63
Florida	7	7
Illinois	32	28
Kansas	96	100
Louisiana	1,380	1,227
Michigan	15	17
Mississippi	52	48
Montana	93	97
New Mexico	165	163
North Dakota	107	108
Oklahoma	169	172
Texas	1,330	1,312
Utah	46	49
Wyoming	143	133
All others	62	66
Total	**5,230**	**5,100**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	5-18-07
Alaska-North Slope 27°	50.90
South Louisiana Sweet	68.00
California-Kern River 13°	54.90
Lost Hills 30°	62.65
Southwest Wyoming Sweet	60.61
East Texas Sweet	62.05
West Texas Sour 34°	54.65
West Texas Intermediate	61.50
Oklahoma Sweet	61.50
Texas Upper Gulf Coast	58.25
Michigan Sour	54.50
Kansas Common	60.50
North Dakota Sweet	55.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	5-11-07
United Kingdom-Brent 38°	66.92
Russia-Urals 32°	60.58
Saudi Light 34°	61.48
Dubai Fateh 32°	62.94
Algeria Saharan 44°	67.40
Nigeria-Bonny Light 37°	67.59
Indonesia-Minas 34°	66.51
Venezuela-Tia Juana Light 31°	57.72
Mexico-Isthmus 33°	57.61
OPEC basket	63.04
Total OPEC[2]	62.55
Total non-OPEC[2]	60.37
Total world[2]	61.55
US imports[3]	58.06

[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]

	5-11-07	5-4-07	Change
	Bcf		
Producing region	717	695	22
Consuming region east	838	777	61
Consuming region west	287	275	12
Total US	**1,842**	**1,747**	**95**
	Feb. 07	**Feb. 06**	**Change, %**
Total US[2]	**1,649**	**1,886**	**–12.6**

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

Statistics

World oil balance

	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.02	21.15	20.88	20.76	21.16	21.24
Canada	2.29	2.27	2.14	2.18	2.26	2.28
Mexico	2.03	1.99	2.02	2.08	2.10	2.06
Japan	5.35	4.81	4.78	5.96	5.46	5.03
South Korea	2.30	2.02	2.03	2.28	2.23	2.01
France	1.96	1.95	1.89	2.10	1.96	2.00
Italy	1.69	1.66	1.63	1.86	1.78	1.68
United Kingdom	1.80	1.76	1.81	1.90	1.84	1.82
Germany	2.70	2.71	2.55	2.56	2.63	2.75
Other OECD Europe	7.42	7.39	7.17	7.36	7.49	7.31
Australia & New Zealand	1.11	1.07	1.06	1.06	1.10	1.04
Total OECD	**49.67**	**48.78**	**47.96**	**50.10**	**50.01**	**49.22**
NON-OECD						
China	7.53	7.25	7.34	6.97	7.07	6.86
FSU	4.90	4.33	4.13	4.50	4.66	4.10
Non-OECD Europe	0.70	0.65	0.69	0.74	0.69	0.64
Other Asia	8.80	8.45	8.52	8.45	8.89	8.27
Other non-OECD	14.48	14.68	14.37	14.20	14.02	14.02
Total non-OECD	**36.41**	**35.36**	**35.05**	**34.86**	**35.33**	**33.89**
TOTAL DEMAND	**86.08**	**84.14**	**83.01**	**84.96**	**85.34**	**83.11**
SUPPLY						
OECD						
US	8.46	8.48	8.35	8.18	7.74	7.95
Canada	3.40	3.32	3.16	3.29	3.28	3.02
Mexico	3.52	3.71	3.79	3.80	3.75	3.72
North Sea	4.76	4.51	4.71	5.11	5.05	4.95
Other OECD	1.52	1.52	1.41	1.41	1.51	1.55
Total OECD	**21.66**	**21.54**	**21.42**	**21.79**	**21.33**	**21.19**
NON-OECD						
FSU	12.40	12.18	11.98	11.74	11.97	11.72
China	3.83	3.83	3.85	3.83	3.75	3.80
Other non-OECD	11.62	11.90	11.74	11.55	11.81	11.86
Total non-OECD, non-OPEC	**27.85**	**27.91**	**27.57**	**27.12**	**27.53**	**27.38**
OPEC	**34.99**	**35.66**	**35.18**	**35.34**	**35.69**	**35.88**
TOTAL SUPPLY	**84.50**	**85.11**	**84.17**	**84.25**	**84.55**	**84.45**
Stock change	**–1.58**	**0.97**	**1.16**	**–0.71**	**–0.79**	**1.34**

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

OECD total net oil imports

	Jan. 2007	Dec. 2006	Nov. 2006	Jan. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,299	–1,608	–1,441	–1,352	53	–3.9
US	12,145	11,525	11,568	12,508	–363	–2.9
Mexico	–1,601	–1,469	–1,761	–1,859	258	–13.9
France	1,694	1,968	1,920	2,126	–432	–20.3
Germany	2,139	2,302	2,478	2,443	–304	–12.4
Italy	1,638	1,712	1,736	1,684	–46	–2.7
Netherlands	1,180	1,009	830	1,182	–2	–0.2
Spain	1,509	1,584	1,634	1,639	–130	–7.9
Other importers	3,909	3,811	4,102	4,038	–129	–3.2
Norway	–2,673	–2,236	–2,459	–2,739	66	–2.4
United Kingdom	104	–4	330	65	39	60.0
Total OECD Europe	**9,500**	**10,146**	**10,571**	**10,438**	**–938**	**–9.0**
Japan	5,558	5,299	5,169	5,750	–192	–3.3
South Korea	2,349	2,250	2,305	2,451	–102	–4.2
Other OECD	763	880	865	961	–198	–20.6
Total OECD	**27,415**	**27,023**	**27,276**	**28,897**	**–1,482**	**–5.1**

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

OECD* total gross imports from OPEC

	Jan. 2007	Dec. 2006	Nov. 2006	Jan. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	480	411	459	439	41	9.3
US	6,093	5,852	5,675	5,522	571	10.3
Mexico	17	43	33	21	–4	–19.0
France	792	913	781	747	45	6.0
Germany	434	337	440	583	–149	–25.6
Italy	1,312	1,372	1,399	1,269	43	3.4
Netherlands	643	603	717	643	—	—
Spain	700	832	744	668	32	4.8
Other importers	1,213	1,342	1,307	1,248	–35	–2.8
United Kingdom	166	182	294	210	–44	–21.0
Total OECD Europe	**5,260**	**5,581**	**5,682**	**5,368**	**108**	**–2.0**
Japan	4,433	4,622	4,511	4,686	–253	–5.4
South Korea	2,294	2,245	2,476	2,441	–147	–6.0
Other OECD	754	768	716	713	41	5.8
Total OECD	**19,331**	**19,522**	**19,552**	**19,190**	**141**	**0.7**

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

US petroleum imports from source country

	Jan. 2007	Dec. 2006	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	778	677	778	713	65	9.1
Kuwait	172	169	172	74	98	132.4
Nigeria	1,136	1,066	1,136	1,186	–50	–4.2
Saudi Arabia	1,563	1,491	1,563	1,369	194	14.2
Venezuela	1,195	1,271	1,195	1,539	–344	–22.4
Other OPEC	1,249	558	1,249	641	608	94.9
Total OPEC	**6,093**	**5,232**	**6,093**	**5,522**	**571**	**10.3**
Angola	778	677	778	713	65	9.1
Canada	2,470	2,412	2,470	2,311	159	6.9
Mexico	1,566	1,366	1,566	1,796	–230	–12.8
Norway	105	178	105	205	–100	–48.8
United Kingdom	194	199	194	187	7	3.7
Virgin Islands	425	334	425	277	148	53.4
Other non-OPEC	1,993	2,313	1,993	2,565	–572	–22.3
Total non-OPEC	**7,531**	**7,479**	**7,531**	**8,054**	**–523**	**–6.5**
TOTAL IMPORTS	**13,624**	**12,711**	**13,624**	**13,576**	**48**	**0.4**

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

Oil stocks in OECD countries*

	Jan. 2007	Dec. 2006	Nov. 2006	Jan. 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	186	192	190	197	–11	–5.6
Germany	285	277	277	287	–2	–0.7
Italy	128	133	133	128	—	—
United Kingdom	106	109	106	102	4	3.9
Other OECD Europe	671	674	663	664	7	1.1
Total OECD Europe	**1,376**	**1,385**	**1,369**	**1,378**	**–2**	**–0.1**
Canada	175	178	184	179	–4	–2.2
US	1,723	1,721	1,746	1,717	6	0.3
Japan	638	631	650	604	34	5.6
South Korea	153	152	158	138	15	10.9
Other OECD	105	103	108	103	2	1.9
Total OECD	**4,170**	**4,170**	**4,215**	**4,119**	**51**	**1.2**

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

Classified Advertising

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

With annual sales over $8 billion, Praxair, Inc. is a global, Fortune 300 company that supplies atmospheric, process and specialty gases, high-performance coatings, and related services and technologies. Our Research & Development division has the following opportunities in TONAWANDA, NY.

Development Associate — GASIFICATION

You will help Praxair advance the effective implementation of existing industrial gases technologies as well as identify/define novel technologies and approaches for the gasification market.

Requirements include a MS or PhD in Chemical or Mechanical Engineering (advanced degree a plus) with 3+ years industrial experience in process development/design related to gasification facilities and/or syngas processes. (Job ID 0700404)

Development Associate — HYDROGEN & ENERGY

You will focus on development and commercialization of hydrogen production technologies; identifying /defining novel technologies and approaches; providing techno-economic evaluations and performing bench and pilot scale tests.

Requirements include a MS or PhD in Chemical Engineering and experience in process development, process simulation, cost estimating and/or techno-economic evaluation. An advanced degree and industrial experience with hydrogen production and/or energy applications preferred. (Job ID 0701120)

To apply, visit our web site at www.praxair.com, Click on Careers, Career Opportunities and Search for Experienced Professional Career Opportunities. Click on the job title from the complete Job List or search by job number listed above. An equal opportunity employer, m/f/d/v.

www.praxair.com

PRAXAIR

Global Mechanical Technologist — JOB ID 0700643

With annual sales over $8 billion, Praxair, Inc. is a global, Fortune 300 company that supplies atmospheric, process and specialty gases, high-performance coatings, and related services and technologies. We are currently seeking a Global Mechanical Technologist in TONAWANDA, NY.

In this exciting role within our Global Supply Systems division, you will travel worldwide to install and commission rotating equipment at Praxair and customer field sites. Working closely with our construction teams, you will oversee a variety of contractors and provide documentation, work estimates and commissioning plans and procedures for new and upgrade process facilities.

To qualify, you must possess an AAS in Technology (Mechanical preferred) and at least 8 years experience in the installation, commissioning and operation of various centrifugal, reciprocating compressors, pumps, fans and/or blowers. You must have a working knowledge of measuring tools and laser alignment equipment and understand installation specifications, civil and mechanical drawings, OEM manuals, drawings, and specifications.

To apply, visit our web site at www.praxair.com, Click on Careers, Career Opportunities and Search for Experienced Professional Career Opportunities. Click on the job title from the complete Job List or search by job number listed above. An equal opportunity employer, m/f/d/v.

www.praxair.com

PRAXAIR

Supervisor, Well Maintenance & Drilling – Big Rapids, MI

TransCanada is a leading North American energy infrastructure company - we build and operate the pipelines, power plants, and gas storage facilities that supply energy to major markets. We are growing - in pipelines, power and expansion into new businesses, including oil pipelines and liquefied natural gas (LNG) facilities.

Consider becoming part of our team and growing with us. We are looking for talented people who have energy for change, can build powerful partnerships, and deliver sustainable results. We offer the challenging work and exciting projects that create boundless possibilities for your career. At TransCanada, our employees are our competitive advantage.

As Supervisor, Well Maintenance & Drilling, you will have direct supervisory responsibility for the Well Maintenance and Drilling group of Reservoir Services located at the ANR Pipeline Woolfolk Compressor Station near Big Rapids, MI. You will provide experienced engineering and supervisory coordination to the department, with emphasis on gas storage well drilling and storage well maintenance project work. With a sound understanding of the high-pressure gas environment, you are the regulatory liaison on compliance issues relating to natural gas storage wells and saltwater disposal wells.

For more information about this position, and to apply, please visit our website at: https://careers.transcanada.com/erc/apply.htm
Refer to Reference Code PRT50014561-01
Posting closes June 15, 2007.

CITGO Petroleum Corporation in Corpus Christi, TX seeks a Reliability Engineer to support operations and maintenance efforts in attaining safety and profitability goals. Candidate must have a Bachelor's degree in Engineering and 5 years experience in the job offered. Please email resume to employment@citgo.com. Please reference job code 56864 on resume.

Classified Advertising

EMPLOYMENT

PDVSA in Houston, TX seeks a Logistics Contracts Administration Analyst for the administration of the contract freight forwarders & inspection companies. Qualified applicants will have a Bachelor's degree in Business Administration or related field & 3 yrs exp. in job offered or 3 yrs related exp. in the oil industry procurement or in lieu of a Bachelors degree in Business Administration or related field will accept 7 yrs exp. in the oil & gas procurement industry. **Contact Aydee Munoz at recruiting@psi.pdv.com. Put job code 53096 on resume.**

Petroleum Geologist/Engineer – Financial Services

Global Resource Investments Ltd. (member NASD/SIPC) is a full service broker/dealer specializing in natural resource investments. With client assets of over $1 billion, our 25-member team has been servicing investors around the world since 1994. We are expanding our staff of account executives and wish to hire an experienced oil & gas professional interested in pursuing a career in the retail brokerage business. Candidate should possess a degree in petroleum geology or engineering, at least ten years field experience preferably in the Lower 48 and/or Western Canada, and excellent verbal skills. Relocation to Southern California and a willingness to pass securities industry licensing exams are required. Please email resume to hr@gril.net or fax to 760-943-3925.

EQUIPMENT FOR SALE

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

EQUIPMENT FOR SALE

AMINE TREATING AND JT PLANTS

FOR SALE OR LEASE
10-75 GPM Amine Plants
5-15 MMCFD JT Plants
Installation & Operations Services
AVAILABLE IMMEDIATELY

TRANSTEX GAS SERVICES
Contact Greg Sargent or Barry Harwell
Phone: 713-654-4440
www.transtexgas.com
Email: info@transtexgas.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
(2) ea. Sulfur Recovery Plant
22T/D
Tail Gas Plant
Amine Treating
300 GPM

BASIC EQUIPMENT
Please call: 713-674-7171
Tommy Balke
tbalkebasic1@aol.com

www.basic-equipment.com

Small Amine Unit

1) Direct fired 6 gpm unit. Includes 18" diameter, 1400 psig contactor. All instrumentation intact.
2) High pressure (1211 psig) 24" contactor. Four 16' packed beds; 20 equivalent trays. From ultra-low dewpoint glycol unit.
3) 15 MMSCFD Expander Plant. Completely skidded. Sundyne Compressor. Rotoflow Exp. All instrumentation intact. Spares.
4) 20 MMSCFD Expander Plant. As above but with high recovery refluxed demethanizer.
5) 14 MMSCFD Nitrogen Rejection Unit good for 10% to 50% N2 inlet gas composition.

Contact: Pierre Lugosch at 281-768-4317

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

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

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.

BUSINESS OPPORTUNITIES

DRILLING PARTNERS WANTED
Offsetting location to two producing wells.
Need two partners, 17% W.I. each.
Cost $30,000 each. Turn Key.
PGP Oil Company. 615-479-4156

REAL ESTATE

Carroll Real Estate Co
Wanted ... ranch / recreational listings
Texas, Oklahoma, New Mexico
903-868-3154

COMPUTER SOFTWARE

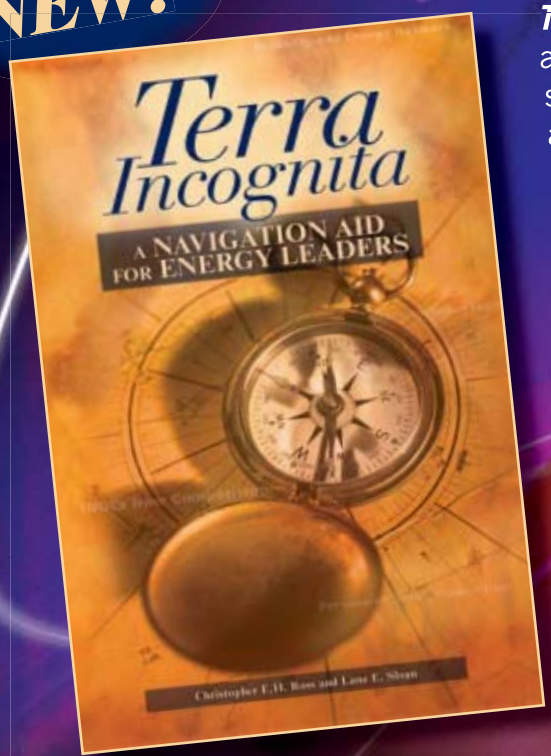
MICA Petroleum Economics
Windows software for evaluating oil and gas reserves. Free production data for 13 states. Contact Petrocalc Corporation at www.petrocalc.com or 719-520-1790.

PennWell Classifieds

Contact: Glenda Harp +1-918-832-9301 or 1-800-331-4463 ext. 6301
Fax: +1-918-831-9776
Email: glendah@pennwell.com

Charting a New Course for Energy Leaders

NEW!



Terra Incognita: A Navigation Aid for Energy Leaders addresses the forthcoming transition in energy supplies, identifies strategic leadership challenges ahead, and summarizes lessons learned from interviews with more than 20 energy company leaders.

In the first book ever written specifically for energy industry leaders, authors Chris Ross and Lane Sloan present:

- The understanding that recent trends are not sustainable, and that enduring energy companies must respond to new technological and social demands and opportunities
- Insights from corporate successes that have demonstrated sustainable and profitable growth since 2001
- Interviews with CEOs of large energy companies on setting direction, executing strategies, and leading their enterprises
- A profile of the energy leader of the future

ISBN 978-1-59370-109-3
544 Pages/Hardcover/6x9/April 2007
$69.00 US

Order Your Copy Today!

www.pennwellbooks.com

Visit us online or call for a free catalog 1.800.752.9764

PennWell®

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
Jean-Pierre Bruel, sas di Jean-Pierre Bruel, Via Trieste 17-22066, Mariano Commense (Co), Italy; Tel: 39-031-51494, Fax: 39-031-751482; E-mail: medias@pcbrianza.net

US politicians need to calm down on energy

The Editor's Perspective

by Bob Tippee, Editor

Before taking another step on energy, US politicians should calm down.

"I start from the presumption," said Sen. Richard Lugar (R-Ind.) at a Deloitte energy conference last week in Washington, DC, "that overcoming US dependence on imported energy and working with other nations to prevent energy crises are fundamental national security imperatives on a par with controlling weapons of mass destruction."

Good grief. If dependence on foreign energy threatened national security to that degree, the US already would be a wreck. It's not. It has been importing oil and natural gas for many years. The foreign share of total supply increases. The economy grows. Even with oil prices high, the economy grows.

Is it the elevated price of gasoline that makes politicians come unhinged this way?

In his speech, Lugar offered a list of "nightmare scenarios" with oil at their center: an embargo, severance by terrorists of "our oil lifeline," and war with an anti-American regime "emboldened by oil wealth." These worries are exaggerated. The modern oil market is too broad, fluid, and buffered by strategic reserves for an embargo to work. There is no "oil lifeline" for terrorists to cut. And no antagonist will challenge the US militarily just because it makes money on oil.

Exporters need to sell oil as much as importers need to buy it. Those relationships provide more security than can come from fearful policy lurches.

Yet Lugar proposes to raise the mandate for fuel ethanol to a stupendously expensive 100 billion gal/year and severely toughen vehicle fuel-mileage standards.

Meeting elevated miles-per-gallon goals with all that ethanol would be no easy trick. But the senator from corn-heavy Indiana apparently doesn't worry about trivialities like ethanol's energy-content disadvantages, which he didn't bother to factor into his oil "savings" calculations.

"Our energy dependence is perpetuated by a lack of national will and focus," Lugar declared.

Baloney. Energy dependence comes with participation in a global economy. A country can't will it away without sacrificing trade and growth. A country's aim should be to stay competitive, not choke itself with uneconomic energy.

Politicians should quit trying to scare people.

(Online May 18, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Supply fears influence markets

The June contract for benchmark US light, sweet crudes topped $65/bbl in intraday trading May 17 on the New York Mercantile Exchange as unexpected shut-ins of US refining capacity "sent shock waves through the markets," analysts said.

Among the disruptions that week, BP PLC said it might delay the restart of a 52,000 b/d gasoline-production unit at its Toledo refinery in Ohio. ConocoPhillips announced it shut in one of three crude units at its 194,000 b/d refinery in Ponca City, Okla., ahead of scheduled turnaround, and that some units at its Sweeny, Tex., refinery were operating at reduced rates. Valero Energy Corp. shut in 64,000 b/d of gasoline production at its Houston refinery for a week.

Meanwhile, analysts in the Houston office of Raymond James & Associates Inc., said, "Above-average weekly gasoline inventory draws this year have left traders skittish regarding gasoline supplies, now 7% below the 5-year average, as we quickly approach this summer's driving season" at the end of May. The American Automobile Association reported the US average retail price for regular unleaded gasoline gained 1.5¢ to a record high of $3.129/gal on May 18, just a week before the US Memorial Day weekend. US pump prices for regular gasoline had advanced 26¢/gal total within 30 days.

The June crude contract traded as high as $65.09/bbl on May 17 before closing at $64.86/bbl, up by $2.31 for the day. The June contract for reformulated blend stock for oxygenate blending (RBOB) jumped by 9.96¢ to $2.44/gal the same day, but it dropped to $2.41/gal in profit taking on May 18. Crude continued climbing to $64.94/bbl. At that point, crude prices had remained above $60/bbl for almost 2 months on the New York market, despite a high degree of volatility from session to session. "We continue to believe that rising global demand, coupled with minimal excess production capacity from the Organization of Petroleum Exporting Countries and increasing visibility of geopolitical risks, are likely to drive oil prices even higher as 2007 progresses," said Raymond James analysts.

Moreover, the North Sea Brent crude contract on the International Petroleum Exchange—now viewed by many as a more accurate benchmark than US crudes on NYMEX—rallied above $70/bbl, representing a $5/bbl premium to benchmark US crudes. In London, the new front-month July IPE contract for Brent crude jumped by $2.30 to $70.27/bbl on May 16 but fell back to $69.43/bbl during profit taking in the next session.

Meanwhile, the value of the US dollar fell against that of most other major currencies after China widened the band in which the yuan can fluctuate against the dollar. That means that crude, which is priced universally in dollars, is cheaper outside the US economy, and similarly reduces OPEC's oil revenue vs. the euro paid for European goods.

Natural gas

Natural gas futures rose above $8/MMbtu May 17 on NYMEX "on fund buying," said analysts at Enerfax Daily. "Speculative traders have been trying to push the market above $8[/MMbtu] but have found higher prices difficult to sustain amid mild weather," the analysts said. Investment funds wanted to escape from the trading range so technical market triggers would kick in to force prices higher. Hedge funds, who had been betting that the price of June natural gas futures would fall, had to buy long positions ahead of warmer weather, analysts said.

The June natural gas contract traded as high as $8.14/MMbtu in the NYMEX session before closing at $8.08/MMbtu, up 18.5¢ for the day. On the US spot market, gas at Henry Hub, La., gained 10¢ to $7.71/MMbtu. On May 18, prices dropped to $7.94/MMbtu on NYMEX but climbed to $7.89/MMbtu at Henry Hub.

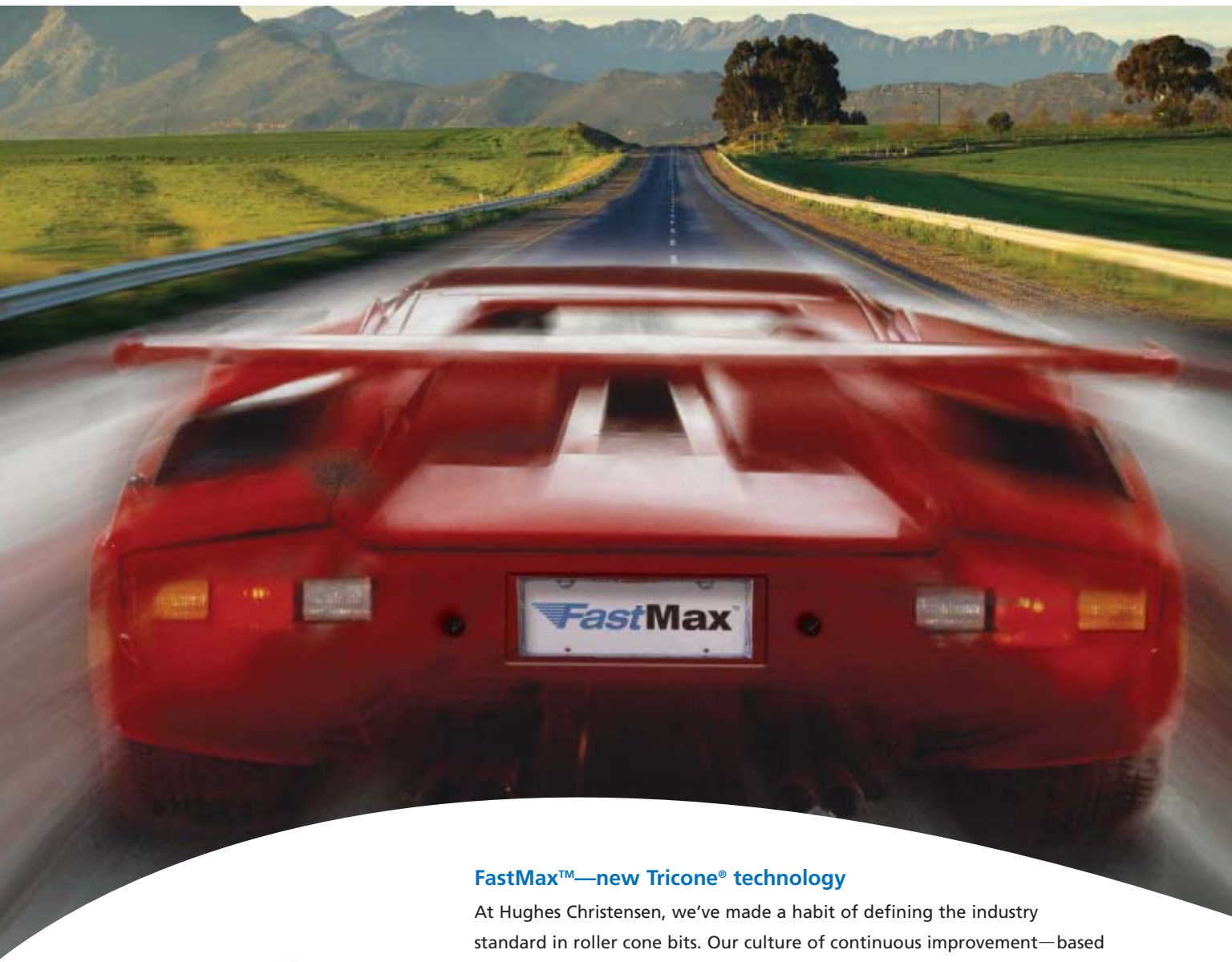
Raymond James analysts reported, "[LNG] imports to the US continue to come in at elevated levels as a result of the remaining supply overhangs in Asia and Europe. However, we believe that increased gas demand fueled by a rising price incentive to burn natural gas over crude derivatives, combined with increased liquid stripping and declining imports from Canada should help offset the increase in [LNG] imports during this injection season."

Analysts at Enerfax Daily said Canadian gas supplies to the US in June may be 600 MMcfd below last year's levels. "Companies cut their drilling budgets last year as prices dipped and well costs soared," they said.

Meanwhile, Raymond James reported May 17, "The natural gas 12-month strip has reached $9/Mcf for the first time in over 8 months; and as such, gas producers can now hedge winter 2007-08 volumes at an appetizing price of over $10/Mcf."

(Online May 21, 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

Flow Control Equipment and Services

Supplement to *Oil & Gas Journal* • May 28, 2007

Technology Forum

OIL&GAS JOURNAL PennWell®

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

SMARTWELL® TECHNOLOGY FOR MARGINAL FIELDS

WD WellDynamics
Transforming Reservoirs™

www.welldynamics.com

Cost-Effective. Reliable. Comprehensive.

SMART.

WellDynamics is the smart choice for cost-effective intelligent completions

Your well doesn't need to produce 1000 barrels a day to justify a WellDynamics SmartWell® completion.

Today's SmartWell MC technology lets you optimize reservoir management and enjoy the benefits of our sophisticated intelligent completion systems in marginal assets.

Using WellDynamics' SmartWell MC valves, packers, gauges and fiber optic technology, you can:

- Monitor and selectively isolate or choke flow from individual zones
- Control the distribution of injected fluids in your wellbores
- Manage data and control wells using portable or permanent control systems

Want to know more about why SmartWell MC technology is a smart choice for marginal fields? Visit our website or contact your WellDynamics representative today.

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Tel 918.835.3161 / Fax 918.832.9290
www.ogjonline.com

PennWell Houston Office
1700 West Loop South, Suite 1000, Houston, TX 77027
Tel 713.621.9720 / Fax 713.963.6285

Managing Editor Bob Williams bobw@pennwell.com
Art Director Alana Herron, alanah@pennwell.com
Production Manager Katie Blair, katieb@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com

— Sales —

US — Southwest, South Texas, Western States, Gulf States, Mid-Atlantic
Marlene Breedlove, E-mail: marleneb@pennwell.com
1700 West Loop South, Suite 1000, Houston, Texas 77027
Tel +1.713.963.6293, Fax +1.713.963.6228

Canada, US — Northeast, New England, Midwest, North Texas, Oklahoma, Alaska
Charlene Burman, E-mail: cburman@pennwell.com
1700 West Loop South, Suite 1000, Houston, Texas 77027
Tel +1.713.963.6274, Fax +1.713.963.6228

United Kingdom
Carole Winstanley, E-mail: adbizmedia@btconnect.com
Adbiz Media Ltd., 252 Union Street, Aberdeen AB10 1TN, Scotland
Tel +44.(0)1224.791178, Fax +44 (0)5601.151590

Scandinavia, The Netherlands, Middle East
David Betham-Rogers, E-mail: davidbr@pennwell.com
11 Avenue du Marechal Leclerc, 61320 Carrouges, France
Tel +33.2.33.282584, Fax +33.2.33.274491

France, Belgium, Spain, Portugal, Southern Switzerland, Monaco
Daniel Bernard, E-mail: danielb@pennwell.com
8 allee des Herons, 78400 Chatou, France
Tel +33(0)1.3071.1224, Fax +33(0)1.3071.1119

Germany, Austria, Denmark, Northern Switzerland, Eastern Europe, Russia
Wilhelm F. Sicking, Verlagsburo Sicking,
E-mail: wilhelms@pennwell.com
Sicking Industrial Marketing, Emmastrasse 44,
45130 Essen, Germany
Tel +49 (0)201.77.98.61, Fax +49 (0)201.78.17.41

Japan
Manami Konishi, E-mail: manami.konishi@ex-press.jp
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

South America
Custodio Sapin, Fausto Motter,
E-mail: pennwell@pennwell.com.br
Grupo Expetro / Smartpetro, Ave. Erasmo Braga 227 — 11th floor,
Rio de Janeiro RJ 20024-900, Brazil
Tel +55.21.2533.5703, Fax +55.21.2533.4593
Url: www.pennwell.com.br

Singapore, Australia, Asia-Pacific
Michael Yee, E-mail: yfyee@singnet.com.sg
19 Tanglin Road #09-07, Tanglin Shopping Center,
Republic of Singapore 247909
Tel +65.6.737.2356, Fax +65.6.734.0655

India
Rajan Sharma, E-mail: rajan@interadsindia.com
Interads Limited, 2, Padmini Enclave, Hauz Khas,
New Delhi 110 016, India
Tel +91.11.6283018/19, Fax +91.11.6228928

Nigeria — West Africa
Dele Olaoye, E-mail: q-she@inbox.com
C1 Alfay Estate, East West Road, Rumuokoro,
Port Harcourt, Nigeria
Tel +234 8 478 6429, Mobiles +234 802 223 2864 &
+234 805 687 2630

Italy
Vittorio Rossi Prudente, E-mail: v.prudente@uniworldmarketing
UNIWORLD Marketing, Via Sorio, 47, 35141 PADOVA, Italy
Tel +39 049 723548, Fax +39 049 8560792

Russia
Svetlana Strukova, E-mail: svetlanas@pennwell.com
PennWell RO in Russia, 115280, Moscow, Russia
Tel +7 495 580 32 01, Fax +7 495 580 32 02
Mobile +7 985 999 90 14

OIL&GAS JOURNAL PennWell

Technology Forum

Flow Control Equipment and Services

Supplement to *Oil & Gas Journal* • May 28, 2007

Controlling sand influx can be critical to controlling and optimizing oil production flow from a well. Here, Baker Oil Tools field service personnel ready an expansion mandrel assembly before running an expandable screen completion. The system can install and expand the sand control screen in a single run. Photo courtesy of Baker Hughes.

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Production flow control evolving into systems approach

The oil and natural gas industry's approach to production flow control is evolving into a more systems-oriented approach that encompasses not only the life of a well but also an entire field's life.

No longer is flow control limited to being an afterthought of completions and simple metering devices. This is a departure from past practices of providing discrete, standard flow control products in a piecemeal fashion.

A more-holistic approach to production flow control is being applied throughout the entire production well stream, from reservoir contact to surface separation. That's a necessity born of the changing nature of production practices today. New reservoirs are discovered in increasingly geologically complex formations. Bypassed potential reserves in highly heterogeneous zones of aging fields are increasingly targeted in mature producing areas.

Service and supply companies now offer complete flow control solutions to meet the needs of operators seeking to save time and money while increasing hydrocarbon recovery and improving field economics.

> "Petroleum engineers have moved beyond experimenting with intelligent well technology [and are] now using these completion tools as part of active reservoir management strategies."
>
> —*Derek Mathieson, WellDynamics*

And the solutions service and supply companies are offering include cutting-edge new technology in production flow control. For example, intelligent flow monitoring and control has become an essential part of the industry's growing acceptance of smart well designs.

Furthermore, production flow control solutions are being designed for the life of a well and with fieldwide applications.

Intelligent wells

Comprehensive solutions for the life of a well are coming into vogue in oil and gas production flow control, and that trend is underpinned with a reliance on intelligent well technology.

"Petroleum engineers have moved beyond experimenting with intelligent well technology [and are] now using these completion tools as part of active reservoir management strategies," says Derek Mathieson, vice-president of business development and technology at WellDynamics.

"Today's key challenges are the following:

- "Selecting and optimizing flow control choke ranges to more closely match expected reservoir conditions and expected changes over the life of the well.
- "Managing a multitude of interfaces with other completion technologies and surface infrastructures to deliver a reliable well solution and not just a product.
- "Providing fieldwide solutions for remote control and flow management where many wells may have a combination of sensing and control technologies."

Systems approach

Flow control should be approached with a "cradle-to-grave" mentality that can result in significant reductions in both capital and operating outlays, according to Joe Jordan, vice-president, cased hole completions, Weatherford International Ltd.

"Our customers are in the business of designing, installing, and operating hydrocarbon recovery systems," Jordan says. "This is fundamental to how our customers perceive the projects they are involved in.

"We believe that we can bring the greatest value to our customers by thinking and acting the same way. On this basis, we offer our customers flow control and well servicing systems tuned to their specific requirements rather than discrete, standard flow control products they simply select from a table in a catalogue."

A systems approach to production flow control should contain a number of key elements to satisfy an operator's needs, according to Mathieson.

"Depending on the scale of implementation," he says, "an operator should look for the following:

- "A detailed interface management plan covering in-well, subsea, and surface components."
- "A control systems philosophy that includes data management.
- "Some form of scenario modeling that illustrates links among reservoir, well, and surface facilities (typically nodal analysis of some form).
- "Where possible, an outline operating philosophy that high-

lights, at a minimum, the critical functionality of the system, with a base plan for operating wells/field under different reservoir or production conditions."

Industry specialists say that two fundamental flow control and well servicing principles are crucial: innovative equipment and techniques, and sound well architecture.

> Flow control should be approached with a "cradle-to-grave" mentality that can result in significant reductions in both capital and operating outlays.
>
> — *Joe Jordan, Weatherford*

The third article in this supplement focuses on some of those innovative equipment and techniques solutions.

Well architecture

In terms of making the best choices in well architecture to optimize flow control, Mathieson contends that the ability to provide flexibility and reliability over the life of the well is paramount.

"What has happened over the last 10 years is the evolution of 'preferred solutions' for specific reservoirs or deployment areas, as the technology, particularly the ancillary equipment needed to integrate well solutions, has evolved," he says.

Examples of these preferred solutions are:

- The two-zone, three-gauge "dip-tube" flow control solution for dual gravel packs in the Gulf of Mexico.
- The multizone (up to six so far) flow control "snake well" solutions for thin oil rims in the Asia-Pacific region.
- The multizone maximum reservoir contact (MRC) solutions for multilateral wells in the Middle East (more details on WellDynamics' MRC solutions in the Middle East appear in the second article in this supplement).

Successful completions

Of course, the starting point for a discussion of specific production flow control solutions is the completion stage of a well. And here, a systems approach is also called for, according to Mathieson.

"Delivering a well or field solution that enables the operating philosophy to be realized is where the bar is now set," he says. "Installing and commissioning reliable equipment is still a subset of this requirement, but it must go hand-in-hand with subsea or surface equipment integration, delivering information in the correct engineering units where decisions can be made, and ultimately being able to demonstrate economic results."

Weatherford adopts such an approach, according to Jordan.

"We work with clients during the completion design phase of a specific application," he says. "At that time, we review all aspects of their installation and testing, potential reservoir and production management activities, and the impact of any future workover operations.

"This process yields two important outcomes. First, customers benefit from our expertise in how to better design their well. Second, we gain detailed knowledge of the specific application, allowing us to make more informed recommendations regarding appropriate flow control and completion equipment choices."]

Long-term view needed for optimum fieldwide flow management

A long-term systems approach is essential for optimizing life-of-field production flow management, say oil and natural gas industry specialists.

Taking a short-term view of production economics—especially taking that view well by well—can crimp future efforts to optimize production for the life of the field. Case histories in the U.K. North Sea and Saudi Arabia provided in this article illustrate this evolving approach.

"Flow management starts before the well is drilled," says Norman W. Hein Jr., vice-president, research and engineering, for VortexFLOW LLC, Midland, Tex. "Saving a small amount of money from using undersized casing, allowing significant wellbore deviations/doglegs while drilling, not adequately handling high-pressure zones, not including appropriate well instrumentation, and then not recording and analyzing these data all inhibit optimization."

"Flow management starts before the well is drilled. Saving a small amount of money from using undersized casing, allowing significant wellbore deviations/doglegs while drilling, not adequately handling high-pressure zones, not including appropriate well instrumentation, and then not recording and analyzing these data all inhibit optimization."

— Norman W. Hein Jr., VortexFLOW

According to Hein, an operator should ask himself whether appropriate tools are being used to determine current operating practices and future well capabilities.

"These include appropriate instrumentation, data loggers, remote terminals for data capture and analysis, and appropriate computer programs being used to effect operations and/or predict future well production capabilities," he points out.

A relatively new company, VortexFLOW has developed a unique new set of tools that it contends represent a revolutionary breakthrough in fluid dynamics technology to help dramatically improve flow in downhole tubing and surface gathering lines.

Optimal production philosophy

Advances in technology are changing the nature of the oil and gas production sector, underpinning the shift to fieldwide flow control solutions and away from well-specific approaches.

"The ability to place observation and control points (i.e., sensors and flow control devices) further upstream than ever before provides the petroleum engineer with the ability to respond to changes in production dynamics as the field matures," says Derek Mathieson, vice-president of business development and technology at WellDynamics. "In this sense, an 'optimal production philosophy' can be set for the different needs of ramp-up, plateau, and decline phases with the same field infrastructure."

"As the industry is moving to fieldwide, rather than well-specific, deployment of these tools," Mathieson adds, "we are seeing more focus on modeling work up front to test the proposed intelligent solution under different reservoir or production conditions."

Mathieson notes that factors affecting fieldwide flow control solutions include:

- Expected reservoir performance.
- Gas- or waterflood expectations.
- Placement of sensors for interpretation of status or disturbances.
- Control system design.
- System performance modeling and understanding—such as managing time delays in long tiebacks, preventing slugging, and optimizing pipeline flow with multiple tie-ins.

Workovers/well servicing

Hein contends that it's also important to keep a long-term view in assessing future workover and well servicing operations as a key to optimizing fieldwide production flow management.

He chides industry for "looking at the short-term solution rather than the full cycle and appropriate long-term solutions

for well optimization.

"As an example, it used to be when gas wells were allowed to load up and eventually die, they were plugged. This left significant amount of reserves in the field.

"As gas prices increase and remain significantly higher, recognizing liquid loading and applying deliquification practices are essential for long-term production."

However, Hein adds, appropriate workovers need to be determined based on the many well production parameters and the remaining well reserves involved.

> "The ability to place observation and control points (i.e., sensors and flow control devices) further upstream than ever before provides the petroleum engineer with the ability to respond to changes in production dynamics as the field matures. In this sense, an 'optimal production philosophy' can be set for the different needs of ramp-up, plateau, and decline phases with the same field infrastructure."
>
> —*Derek Mathieson, WellDynamics*

Saudi case history

A joint venture of Saudi Arabia's state oil company Saudi Aramco and WellDynamics earlier this year announced plans to develop new technologies for a fieldwide multilateral/multizone intelligent completion system.

"This joint development project is part of Saudi Aramco's overall vision to develop Extreme Reservoir Contact (ERC) wells," said Amin Nasser, Saudi Aramco vice-president of petroleum engineering and development, in a Saudi Aramco statement. "ERC wells are intelligent multilateral wells that do not require individual control lines from the wellhead to each lateral or zone, and therefore, theoretically allow an unlimited number of intelligent laterals."

Saudi Aramco pioneered intelligent Maximum Reservoir Contact (MRC) wells, which attain more than 5 km of contact with the reservoir through intelligent laterals off the main wellbore that can be partially or fully opened and closed from the surface. Saudi Aramco's most recent major new development, Haradh Increment III, completed in early 2006 in Haradh supergiant oil field with a production capacity of 300,000 b/d, relies on 32 intelligent MRC wells that utilize WellDynamics' SmartWell intelligent completion technology.

"Intelligent MRC wells can have only a limited number of laterals (four to five), because each downhole control valve requires a mechanical control line to the wellhead. ERC wells would relax this requirement," explained Muhammad Saggaf, manager of Saudi Aramco's EXPEC Advanced Research Center (ARC). "We envision ERC wells of 50–100 smart laterals that would efficiently drain the reservoir and ultimately maximize economic recovery."

The Saudi Arabia project consists of the development of a unique telemetry system coupled to a subsurface control module that will control flow and transmit data from and to each "smart" lateral to the main wellbore, and ultimately to the surface. The system reduces technical risk by taking advantage of WellDynamics' SmartWell products for basic monitoring and flow control functions within the laterals.

The development project will be executed by a technical team comprising researchers from Saudi Aramco's EXPEC ARC and WellDynamics.

UK North Sea case history

Another case history of this approach involves the work Weatherford International Ltd. did for BP PLC and its partners in the Eastern Trough Area Project (ETAP) in the UK North Sea.

The BP-operated portion of ETAP posed a challenge in that it involved four separate fields with varying well conditions: Marnock, Mungo, Machar, and Monan.

Weatherford became involved very early in well planning, says Joe Jordan, vice-president, cased hole completions, for Weatherford. This allowed the company to take a systems view of the well architecture required in terms of flow control and well servicing.

"We were able to participate in completion design changes that will fundamentally impact the ease with which the wells can be serviced later in field life," Jordan adds. "For instance, on Mungo, we recommended a change in liner size to ensure reservoir access with mechanical retrievable bridge plugs for possible future zonal isolations."

In addition, using the Uniset Well Servicing System allowed well architecture to be optimized in terms of life-of-field well servicing requirements, he says: "The use of Uniset nipple profiles in third-part-supplied equipment such as tubing hangers and safety valves brought the benefits of the system to the whole well design, not just the components supplied."

Weatherford approached the project with the intent of minimizing BP's capital outlays in terms of equipment inventory, Jordan says.

"To achieve the well designs for the four separate fields, we tried to give maximum possible commonality of equipment from one field to the next, thereby minimizing the overall equipment outlay."]

Integrating step-technologies enhancing production flow control

New technologies are rapidly coming to the forefront to aid operators in the control and monitoring of oil and natural gas production flow.

Technology is at hand to install intervention-less completions, or to design them as part of an integrated flow control system so that future workovers and service jobs are as painless as possible.

Intelligent well solutions are leading the way, as are advances in tubular goods, sand control, and flowmeters.

Step-change technologies

"There has been a lot of activity over the past few years in bringing together step-change technologies such as expandables, swellable elastomers, and intelligent flow control and monitoring into individual wells," says Derek Mathieson, vice-president of business development and technology at WellDynamics. "This activity has already opened up a wealth of new solutions for flow control, including multizone sand control and openhole solutions."

Production flow control equipment can do much more than simply control production or injection after installation, according to Michael Konopczynski, manager of reservoir solutions and commercialization at WellDynamics International Ltd., Spring, Tex. "The synergy among flow control, monitoring, and production stimulation holds great promise to improve the effectiveness of treatments through controlled placement, clean-up, and real-time evaluation of the operation.

"Improved acid placement or fracture treatments will be enabled by new, fit-for-purpose technologies to enable wellbore segmentation and flow control for stimulation purposes," he says. "Ultimately, the combination of managed-pressure drilling—which promises to deliver wellbores with reduced impairment—with underbalanced intelligent completions could provide significant improvements to well deliverability. The use of production flow control could be a significant catalyst to achieving this goal."

Downhole monitoring

Exciting new developments are ongoing in the area of cableless systems and reservoir monitoring solutions, notes Mathieson.

"Cableless technologies will enable another suite of applications for multilaterals, in which each individual lateral can effectively be monitored and controlled as an individual multizone well," he points out. "Longer term, it may even be possible to retrofit these types of solutions into existing wellbore architectures, opening another range of solutions that impacts a much wider spectrum of wells."

Increasingly, permanent downhole pressure and temperature sensors are now deployed in a large percentage of new wells, notes Mathieson.

"The synergy among flow control, monitoring, and production stimulation holds great promise to improve the effectiveness of treatments through controlled placement, clean-up, and real-time evaluation of the operation."

— *Michael Konopczynski, WellDynamics*

"However, more activity is now in place to create a range of sensor solutions more directly related to reservoir management, such as flow monitoring, flood front monitoring, and many others," he adds. "While none of these topics is new, the technology is reaching a level of maturity that could result in much more widespread deployment looking out over the next 10 years."

Workovers, well servicing

In optimizing future flow management, operators have a number of critical design parameters to consider in setting up workover and well service programs for the future.

"For tubing-conveyed downhole equipment, having a sufficiently large inner diameter for through-tubing operations is normally a required design criterion," Mathieson says. "For flow control valves, the ability to achieve a manual override in the event of a device failure is also desirable."

Joe Rhone, president of VortexFLOW LLC, Midland, Tex., concurs with that view: "Tubulars should be as large as possible to accommodate future production lift equipment. Small casing dooms a well and causes operating problems over the life of the well. You have to look beyond short-term

economics of drilling/completion and towards a full-life depletion plan."

For some workover operations, such as electric submersible pump changeovers, equipment such as hydraulic and electric disconnects can allow lower completions to remain in place and be reconnected while the upper completion is replaced, according to Mathieson.

His WellDynamics colleague, Konopczynski, adds, "This ability has an additional benefit of being able to shut off communication with the reservoir for the duration of the workover to avoid losses of workover fluids to the formation and to prevent the associated formation impairment."

Thinking ahead at the initial completion stage can be crucial for designing future workover operations.

"Generally, most completion designs can be configured to have specific sections where future sidetracks can be placed or where downhole umbilicals can be more readily sheared, etc.," says Mathieson. "These configurations can be as simple as specific space-outs at certain points, additional landing nipples, or additional clamps that facilitate certain parts of potential future workover operations."

Stephen A. Sakowski, Baker Oil Tools production engineering applications advisor, cased-hole completions/intelligent well systems, contends that, ideally, advanced-technology flow control systems are designed as part of intervention-less completions that eliminate the need for pulling equipment for workovers over the life of the well.

"If not," he says, "it is important that flow control systems include a capability to 'disconnect' the downhole equipment at some point to allow the upper completion to be pulled for workover operations."

Innovative completions

There are critical choices to be made in well architecture in order to optimize flow control in today's challenging completions, according to Sakowski.

"Maintaining as large a borehole or casing size as possible affords maximum flexibility to the flow control solutions available to the completions engineer," he says. In addition, "a well architecture that provides effective isolation of the reservoir zones (or well segments) of interest is essential to permit optimized flow control in any well."

Understanding the inflow performance characteristics of the zone(s) to be controlled offers the best chance to design the optimum completion for a given flow control application, Sakowski contends: "A successful completion will include the capability both to measure the key flow performance data and to adjust the flow performance from each flow path in the well, whether they be multiple reservoir zones or multiple well segments in the same reservoir zone."

The bottom line, says Sakowski, is that a systems approach to implementing flow control technology is critical to success of these advanced-technology completions.

"Operators should require that all components of such completions be designed, procured, installed, and maintained as an integrated system," he says.

Sand control

Sand control technology in particular is enjoying a period of significant technological growth, with the advent of passive control solutions also known as "interval control devices" (ICDs), according to Mathieson.

"ICDs provide the well designer with a means of effectively setting a fixed choke along a length of the wellbore at the time of well construction, allowing a crude form of flow control to balance drawdown, particularly in long horizontal wells or in sections of high permeability," he says.

For improved sand control, Sakowski would like to see "lower completions that allow near-full-bore access for placement of production flow control equipment."

Flow measurement

Eliminating uncertainty is key to advancing the technology of production flow measurement. That applies to assurances about the reliability of flowmeters as well as their accuracy.

Tom Moser, president of the Micro Motion Inc. division of Emerson Process Management, contends that although Micro Motion Coriolis technology is widely employed in production flow measurement applications, "we feel our recent developments in providing an easy inline verification of meter integrity is going to deliver even more value to our customers.

"Lower maintenance cost is the most obvious benefit, as meters no longer need to be pulled from service for inspection or verified through a calibration. We feel the added assurance that production decisions are based on reliable flow measurements from well testing facilities will also be

> "...Our recent developments in providing an easy inline verification of meter integrity is going to deliver even more value to our customers. Lower maintenance cost is the most obvious benefit, as meters no longer need to be pulled from service for inspection or verified through a calibration."
>
> — *Tom Moser, Micro Motion/Emerson*

"As an industry, we are currently challenged by a shortage of experienced personnel, making measurement and optimization difficult as we are forced to address problems in a 'triage' fashion. Perhaps...the most significant challenge to production control is the adoption of new technologies. How can we provide a platform for providing 'open source' solutions to common production flow problems?"

— *Joe Rhone, VortexFLOW*

beneficial to the upstream industry."

Moser also notes that flow production measurements can be affected by entrained gas situations associated with undersized test separators, abnormal process conditions, or design challenges in maintaining the bubble point of the oil.

"The new capabilities of Emerson's Micro Motion Coriolis technology to maintain acceptable levels of volume flow accuracy under entrained gas conditions is starting to be applied in upstream applications," he says. "Initial results are very encouraging, and we are continuing to expand the application base for this technology in order to provide more reliable flow measurement solutions for our customers."

In addition, the growing acceptance of compact separation technology, in conjunction with a Coriolis flowmeter as a multiphase meter, is helping upstream facilities to reduce overall production measurement uncertainty, says Moser: "We have been working closely with suppliers of this technology, which is resulting in lower capital expenditures related to surface equipment and more reliable, accurate, and representative well production data."

Industry needs meters that can accurately determine velocity and constituency at a reasonable cost, Rhone contends, adding, "We have experienced this directly as we experiment with measurement of water and air flow in our lab."

Flow efficiency

New technology to improving flow efficiency has been the driver behind VortexFLOW's genesis and rapid growth.

A relatively new company, VortexFLOW has developed a unique new set of tools that it contends represent a revolutionary breakthrough in fluid dynamics technology to help dramatically improve flow in downhole tubing and surface gathering lines.

"At Vortex, our focus has been on understanding how to improve single-phase and multiphase flow efficiency, whether in gathering systems or downhole," says Rhone. "As we have worked to understand how our tools perform under various conditions, we have learned to appreciate the challenge of obtaining true and accurate measurements of the conditions in the wellbore (bottomhole pressure, fluid level, velocity, etc.).

"While some technologies exist to measure these conditions—Echometer's plunger performance measurement, fluid gradients, pressure bombs, etc.—they are often not utilized. Measurement, measurement, and more measurement will be the key to understanding how to improve production flow control."

Game-changing technologies

Rhone's comment about measurement underscores his view that there is no "silver bullet" for optimizing production flow control.

"Instead, it is likely many technologies will be used over the life of the well to optimize production," he points out.

Sakowski offers his list of where industry needs to develop game-changing technologies in the production flow management arena:

- "Multiphase production—effective downhole multiphase flow measurement.
- "Multizone completions—the ability to place and operate production flow control equipment in each leg of multilateral wells, and retrieve as required.
- "Intelligent wells—reduction or elimination of control lines and instrument cables to downhole flow control and measurement tools.
- "Deepwater wells—electrically operated safety valves and downhole flow control devices to minimize response time inherent in hydraulic systems.
- "Horizontal/extended-reach wells—effective identification and isolation of well segments for control."

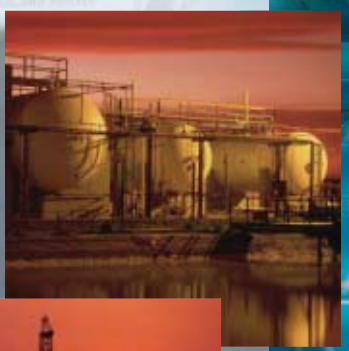
Developing those new technologies may well prove to be a sizeable challenge for an industry already strained to the breaking point, however.

"As an industry, we are currently challenged by a shortage of experienced personnel, making measurement and optimization difficult as we are forced to address problems in a 'triage' fashion," Rhone notes. "Perhaps...the most significant challenge to production control is the adoption of new technologies. How can we provide a platform for providing 'open source' solutions to common production flow problems?"]

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

We Keep You Flowing From Drillfloor to Downhole.

2 *Grooved Meter*

There's only one choice for every critical, complex flow measurement application in the offshore drilling, production and well-servicing environment: Hoffer Flow Controls. From the drillfloor to the seabed and downhole, Hoffer offers you design solutions with the only complete flow measurement package in the industry.

Our high-pressure wing nut turbine meters and grooved end turbine meters have long been the preferred choice with well-servicing companies worldwide for use on cementing and frac-ing skids and in well-stimulation programs. With a proven track record on thousands of jobs worldwide, you get flowmeters that can measure everything from produced water and nitrogen to cement and sand slurries at pressures up to 15,000 PSIG. In fact, we're setting a new standard for mud pump drilling fluid flow measurement today.

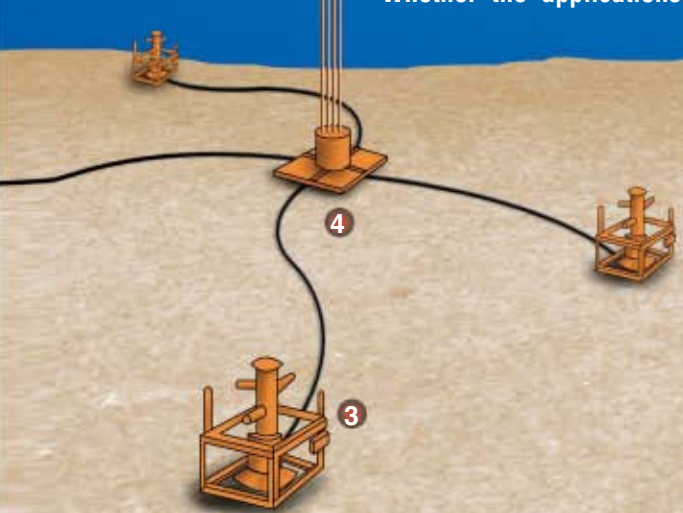
Hoffer offers you unmatched flow measurement performance. Whether the applications are on BOP, wellhead and subsea systems or hydraulic and lubricants for your drilling systems and ROV's, our standard and custom HO Series of turbine flowmeters will meet or exceed your expectations. We design and build meter packages to your criteria for the demanding world of downhole tool flow measurement. Whether you're working in water depths to 10,000 feet and below or in small or large line sizes, we know how to deal with pressure.

3 *H.O. Series Meter*

With more than 30 years in the flowmeter business, we continue to set the standards for accuracy, reliability, durability, economy and integrity. In fact, no other company offers you more measurement solutions to the oil and gas industry than we do. Put us to the test, and find out how Hoffer turbine flowmeters give you complete measurement and control from the drillfloor to downhole. Call us today at 1-800-628-4584.

1 *Wing Nut High Pressure Meter*

4 *Subsea Meter*



HOFFER FLOW CONTROLS, INC.
The Turbine Flowmeter Company™

www.hofferflow.com/oilandgas