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Fischer-Tropsch Gets a New Look

Senegal exploration expands Petrobras Africa operations
Study: Horizontal drilling to improve Algerian oil field output
New model predicts solubility in glycols
Past contamination, future land use set abandonment time line

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Feb. 26, 2007
Volume 105.8

FISCHER-TROPSCH GETS A NEW LOOK

REGULAR FEATURES

COVER

The Sasol Advanced Synthol reactor featured on the cover is one of nine reactors used in the Sasol Fischer-Tropsch process that converts coal to liquid hydrocarbons at the Sasol plant in Secunda, South Africa. The facility, resembling a nuclear power plant with its concrete silos, superheats coal to more than 2,000° F., adds steam and oxygen to make syngas (H_2 and CO), increases the pressure, and converts the syngas via Fischer-Tropsch synthesis to liquid fuels. The original plant was built to produce transportation fuels from coal following fuel embargoes during World War II. A third plant, the 40,000 b/sd Sasol III, was completed in 1983 on the site. Sasol produces 38% of South Africa's fuel requirements. Photos courtesy of Sasol Ltd.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Brazil, Bolivia sign natural gas-price agreement

After months of negotiations, Bolivian President Evo Morales and his Brazilian counterpart Luiz Inácio Lula da Silva have signed a protocol agreement that formalizes an increased price for natural gas that Bolivia exports to Brazil. Brazil agreed to pay $4.20/MMbtu for Bolivian gas. This is an increase from the previous $1.09/MMbtu rate. The agreement refers specifically to gas used by a thermoelectric power plant in Cuiaba, in western Brazil, where 1 million cu m/day of gas is delivered via a 267-km pipeline in which Royal Dutch Shell PLC holds a 38% stake (OGJ Online, Jan. 30, 2007).

Carlos Villegas, Bolivia's hydrocarbons minister, described the agreements as very encouraging in terms of bilateral relations between the two countries. The agreements point to a mutual commitment to enter a new phase of energy cooperation, he said.

No agreement, however, has been reached concerning Brazil's imports of 26 million cu m/day—about half of Brazil's daily gas consumption—through the 3,150-km Bolivia-Brazil gas pipeline. Brazil pays slightly higher than $4/MMbtu on average for this gas. Bolivia wants Brazil to pay about $5/MMbtu for the gas, after reaching a similar agreement with Argentina.

Transneft: Russian elections won't affect projects

Russian pipeline operator OAO Transneft is committed to implementing its oil projects regardless of any change in Russia's presidency in the forthcoming elections, Transneft Pres. Simon Vainshtock told OGJ at International Petroleum Week in London.

"Russia has prepared all the necessary grounds for there to be a continuity of energy policy that we currently have. The policy will be maintained and will remain the same," Vainshtock said.

One major Transneft project is construction of the 4,000-km Eastern Siberia-Pacific Ocean pipeline to export Russian crude to the Asia-Pacific region. Vainshtock said the first phase of the 30 million tonne/year pipeline is on schedule to be commissioned in 2008. "We've got guarantees for 100% of the volumes to fill the first stage of the pipeline," he said.

Russia, Bulgaria, and Greece recently signed a preliminary agreement for the 240-km Burgas-Alexandroupolis oil pipeline proposal to fast-track the establishment of an international company to manage the project. The pipeline, with an initial capacity of 15 million tonnes/year, will skirt the Black Sea, cross Greece and Bulgaria and help reduce crude oil shipments by tankers through the congested Bosphorus and Dardanelles straits.

Vainshtock added that Transneft will support OAO Gazprom's position not to ratify the Energy Charter Treaty because they are both state energy companies. The international agreement aims to protect foreign energy investments. Russia signed the treaty but refused to ratify it, saying it does not serve Russian interests, because of objections to the Transit Protocol, a related document that facilitates the transit of hydrocarbons.

Russia is negotiating with the European Union to reach a resolution on this document before it will progress with ratification.

Excelerate begins operations of Teesside GasPort

Commercial operations have started at Excelerate Energy's GasPort in Teesside in northern England, opening the possibility of supplying as much as 600 MMcfd of peak gas directly into the UK national grid system.

GasPort is the world's first dockside regasification application—a land-based manifold that connects to a high-pressure gas arm on Excelerate's specially adapted Energy Bridge Regasification Vessel (EBRV), which can regasify LNG onboard.

"The technology platform on which the Teesside GasPort is based has long-term implications for the LNG industry," said Rob Bryngelson, Excelerate Energy executive vice-president and chief operating officer. "GasPort operations are further enhanced by the ability of Energy Bridge vessels to conduct commercial ship-to-ship transfers with conventional LNG vessels, an ability that aggregates global LNG supplies and markets, shortening travel time and reducing costs." RWE Trading will market the gas from GasPort to UK customers. Both hope to develop additional LNG infrastructure in other European markets.

OGJ joined senior UK gas industry officials at the inauguration ceremony Feb. 20 in Teesside where the company stressed it has delivered the project in under a year and offers a substantial cost effective solution to LNG regasification needs. GasPort cost £40 million whereas traditional land based regasification terminals are at least £400 million. It was particularly proud of launching GasPort with its first commercial ship-to-ship transfer of 130,000 cu m of LNG, and Excelerate hopes to capitalize on meeting short-term LNG demand (OGJ online, Feb. 16, 2007).

Excelerate will forge key commercial relationships with industry participants via Excelerate GasNet, a logistical services and trading platform, to deliver LNG supplies to customers in North America, Europe, and elsewhere worldwide. ✦

Exploration & Development — Quick Takes

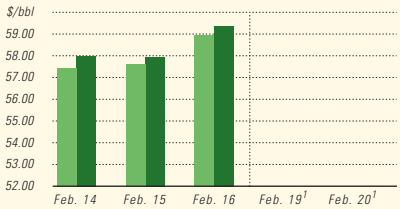
BP assesses gas hydrates with ANS well

BP Exploration (Alaska) Inc., in collaboration with the US Department of Energy and the US Geological Survey, has drilled a well on the Alaskan North Slope to assess the potential of gas hydrates as a long-term nonconventional energy source.

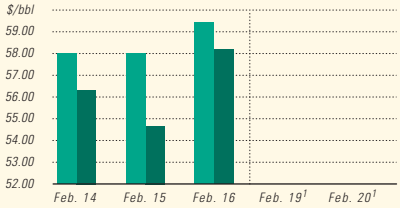
The well is 1.4 miles south of the Milne B-pad in Milne Point

Industry Scoreboard

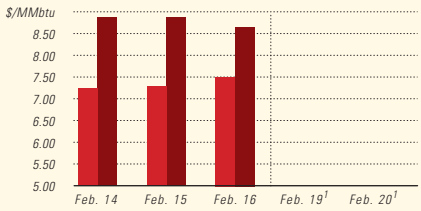
IPE BRENT / NYMEX LIGHT SWEET CRUDE



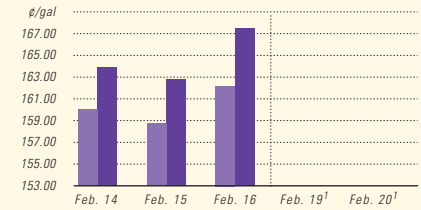
WTI CUSHING / BRENT SPOT



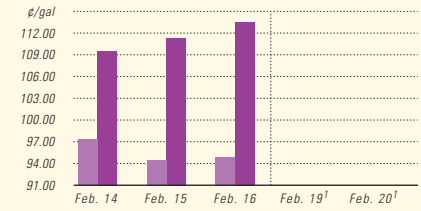
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



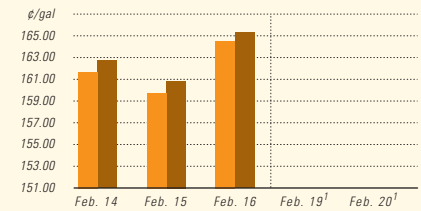
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available.
[2]Nonoxygenated regular unleaded.

SCOREBOARD

Due to the holiday in the US, data for this week's industry Scoreboard are not available.

oil field northwest of BP's Prudhoe Bay oil field.

Drilled to 3,000 ft, the stratigraphic test well intersected the Sagavanirktok formation on the Mt. Elbert prospect, which was identified by seismic data, well, and reservoir modeling studies.

About 430 ft of 3-in. hydrate cores were collected. The core segments were initially subsampled and analyzed on site due to the time and temperature-dependent data requirements. They will be shipped to Anchorage for temporary storage before being distributed to gas hydrate researchers around the country.

Subsequent data collection and analysis will continue for several months, after which a report will be published, BP said.

The well provided a stratigraphic test of interpreted gas hydrate accumulations from Milne seismic and well data. Core, wireline logs, and wireline downhole testing will help assess gas hydrate-bearing sediment, shallow reservoirs, and fluid properties.

The project resulted in the first significant collection of gas hydrate-bearing cores in Alaska, and the first delineation of a seismically defined gas hydrate prospect in Alaska.

Production tests and other future developments of the Milne test well will be determined jointly with DOE, which funded the estimated $4.6 million drilling cost.

Gulfsands, Emerald spud third well on Syria's Block 26

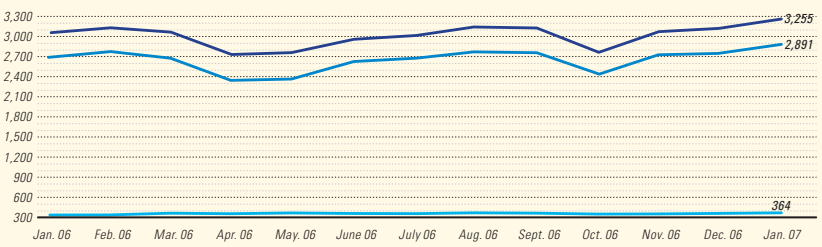
The Khurbet East No. 1 exploration well on Block 26 in Syria has been spudded using the Crosco 2000 HP Emsco 602 drilling rig, according to Emerald Energy, a partner in the block. The well, which is expected to reach TD of 3,700 m over the next 100 days, is targeting a fault-bound structural culmination, with closure mapped at several potential reservoir levels, including Cretaceous, Triassic, and Palaeozoic ages.

The Khurbet East prospect is about 12 km southwest of the Souedieh oil field and 12 km south of the Roumelan oil field.

The Block 26 partners, Emerald Energy and Gulfsands Petroleum (operator), have exploration rights in all reservoir levels of Khurbet East. Each company has a 50% stake in the block.

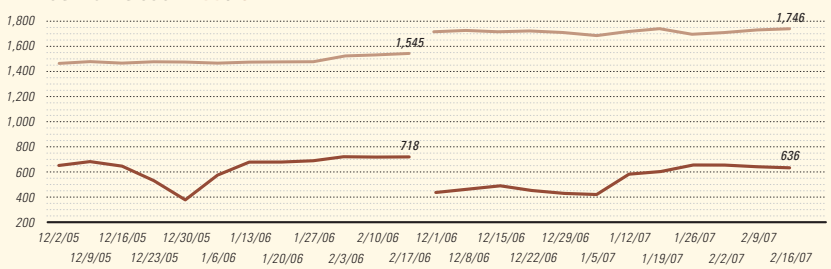
Gulfsands said that in the event of an oil or gas discovery at Khurbet East, production would be tied back to existing facilities about 12 km away near Roumelan field.

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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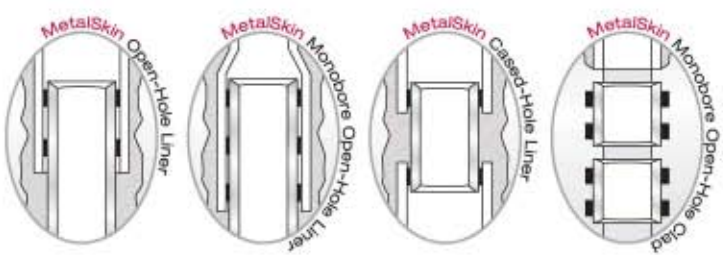

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This is the third well in the partners' drilling program for Block 26, and they will drill their fourth well starting in July.

Norway extends Goliat oil license in Barents Sea

Norway's Oil and Energy Minister Odd Roger Enoksen will grant the Goliat license partners additional acreage to explore in the Barents Sea, after studies suggest the oil reservoir could expand into an area not covered by the original license.

Goliat partners are Eni SPA 65%, Statoil ASA 20%, and DNO ASA 15%. Eni Norge AS submitted the extension application on behalf of the licensees in PL 229, and the partners will drill an extra exploration well to assess the extent of the resources.

Enoksen said this new acreage will be included in Goliat's development plan scheduled for 2008. The Goliat license covers 5 blocks with an area of 1,010 sq km.

Goliat is one of the most significant future field developments on the Norwegian continental shelf, Enoksen said recently. The license is 50 km southeast of Snøhvit field and 85 km northwest of Hammerfest.

In a separate development, the Norwegian government has offered 13 new blocks in the Barents Sea to interested applicants under its Awards in Predefined Areas 2007 (APA 2007) licensing round.

Companies must submit their applications by Sept. 28 and can apply for all blocks or parts of blocks that have not been allocated under a license. The Norwegian Petroleum Directorate said these were the first blocks on offer in the Barents Sea since APA 2004, and it plans to announce the winners by late this year or early in 2008.

Statoil to drill Snøhvit appraisal well

Statoil ASA and its partners have decided to drill an appraisal well in the Snøhvit field to aid in determining whether to continue with the Barent's Sea project.

The appraisal well will provide further data on the recoverable oil reserves and better map gas reserves in the western part of the field's structure, the company said.

Several development options have been under consideration, including a potential coordination with the Goliat oil find development, operated by Eni SPA. The coordination with Goliat was studied earlier with a negative result, Statoil said.

Drilling of the appraisal well is dependent on available rig capacity in the area.

Statoil is operator for development and operation of Snøhvit with a 33.53% share. Other partners are Petoro SA 30%, Total E&P 18.40%, Gaz de France 12%, Amerada Hess Norge 3.26%, and RWE Dea Norge 2.81%.

Heritage Oil to test deeper zones in Ugandan well

Heritage Oil Corp. plans a production test of deep intervals in the Kingfisher-1A deviated exploration well on Block 3A in Uganda. Three intervals, with a total thickness of 44 m, are to be tested at depths of 2,260-2,367 m.

The upper zone of the Kingfisher-1 well, at a depth of 1,783 m, was tested successfully in November 2006, flowing at a stabilized rate of 4,120 b/d through a fixed 1-in. choke at a wellhead pressure of 221 psi. The reservoir had permeability of over 2,000 md.

The 30° gravity oil was sweet with a low gas-oil ratio and some associated wax (OGJ Online, Nov. 7, 2006).

Kingfisher-1A was drilled to 3,195 m. Wireline logs and formation pressure testing indicated hydrocarbons over the planned test intervals, the thickest of which is 21 m.

The production test is scheduled to start by Feb. 25 and is expected to take as long as 3 weeks.

Heritage operates Block 3A, holding 50% interest, and Tullow Oil holds 50% interest.

Total's Egina field to be stand-alone development

Total SA said Egina oil field, which holds several promising discoveries, may be suitable for stand-alone development. The field is on Total-operated license 130, about 150 km off Nigeria.

The Egina-1 discovery well, drilled in December 2003, and the Egina-2, drilled in October 2004, revealed the presence of a new structure. After reprocessing existing seismic data, Total launched an appraisal program to size the Egina discovery.

The Egina-3 (September 2006), Egina-4 (November 2006), and Egina-5 (January 2007) wells, drilled in about 1,500 m of water, encountered 60-80 m of oil in Miocene sands. They confirmed the possibility for a stand-alone development of the field.

Tests of the Egina-5 well suggest the well's production potential could reach 12,000 b/d.

Egina-1 lies 20 km from Akpo gas-condensate field, which is scheduled to start production in late 2008 and quickly peak at 225,000 boe/d, 80% condensate. Akpo was discovered in 2000. ✦

Drilling & Production — *Quick Takes*

FCP to produce from Algeria's MLE field in 2009

First Calgary Petroleums Ltd. (FCP) will produce 200 MMcfd of gas from MLE oil and gas field in Algeria's Berkine basin and will build infrastructure with Sonatrach by late 2009 under a $1.3 billion development plan.

MLE, which has 230 million boe of reserves, will send gas to a new gas plant, field gathering system, and facilities designed to process 230 MMcfd of raw gas on a gross basis along with associated natural gas liquids and oil. There are proposals to increase the plant's capacity to as much as 400 MMcfd.

MLE's production plateau of 200 MMcfd is over an initial 10 years, and it will produce 21,000 b/d of oil, condensate, and LPG. Sonatrach will market the gas.

MLE is on the eastern part of Block 405b. The block will be developed in stages to exploit oil and gas discoveries west of MLE field after the companies finish appraisals and determine their commerciality.

The joint venture will construct dry gas and liquids pipelines from Block 405b to a tie-in point on the national pipeline grid about 140-km west of the block, said FCP. "In addition, an oil pipe-

line is planned to be built to a tie-in point on an existing oil pipeline in the Berkine basin (PKO)."

FCP will provide 75% of the $1.3 billion costs, and Sonatrach, will provide 25%.

BP to boost CBM production in San Juan basin

BP PLC reported it plans to invest as much as $2.4 billion over the next 13 years to boost by more than 20% its 425 MMcfd share of coalbed methane gas production in the San Juan basin of southwestern Colorado.

BP said it will drill more than 700 wells from existing well pads in the basin. It has already acquired regulatory infill approval and associated field infrastructure.

CBM constitutes 10% of gas production in the US. The San Juan basin project is a major initiative for BP that is part of a 10-year, $45 billion oil and gas exploration and production program in the US that includes major investments in the deepwater Gulf of Mexico, Alaska, and the Lower 48 states.

PTTEP starts gas, condensate output from Shams

Thailand's PTT Exploration & Production PCL (PTTEP), operator of Oman's Block 44, has begun production of natural gas and condensate in its Shams (Sun) field, about 300 km west of Muscat.

Production from the field, which is part of Block 44, is averaging 50 MMscfd of gas and 4,000 b/d of condensate.

Gas from the field will be sold to Oman's oil and gas ministry in accord with a gas sales agreement concluded on Apr. 27, 2005, while condensate will be exported to PTT PCL, PTTEP's parent company in Thailand.

PTTEP became operator with 100% interest in Block 44 following an exploration and production-sharing agreement signed with Oman's oil and gas ministry on July 21, 2002.

PTTEP lets contract for Arthit field development

PTTEP has awarded Technip a contract for the detailed engineering of four generic wellhead platforms with associated subsea pipelines and tie-ins.

The platforms will be installed in the Arthit natural gas field in 80 m of water in the Gulf of Thailand, and tied to existing wellhead platforms.

The contract covers engineering services, which are to be completed in May, as well as the preparation of purchase requisitions for all long-lead items.

Technip said its operations and engineering center in Bangkok will execute the contract with pipeline engineering support from the Technip operations and engineering center in Kuala Lumpur.

In January, PTTEP said it expected the offshore Arthit gas field to start production in first quarter 2008 with an initial capacity of 330 MMcfd of gas.

JV ramps up gas production from Phu Horm field

A group led by Hess Corp. has ramped up natural gas production to 100 MMcfd from Phu Horm field, Thailand's second onshore producing gas field.

The increase followed an initial run starting on Nov. 30, 2006, when the field, which lies in the northeastern province of Udon Thani, produced 60 MMcfd of gas (OGJ Online, Dec. 6, 2006).

Consortium officials said the production increase is in response to demand from an electric power plant and to make up for the decline in gas output from Nam Phong, the depleting gas field just north of Phu Horm.

Production from Nam Phong, operated by ExxonMobil Corp., has fallen to about 30 MMcfd now though it is expected to go on producing over the next decade, albeit at the declining rates.

The combined production from Phu Horm and Nam Phong has enabled the Electricity Generating Authority of Thailand to run at its full capacity of 720 Mw.

Phu Horm's current production comes from three wells. The consortium plans to drill three more wells this year, comprising two development wells and one appraisal well, in the 232-sq-km concession block.

Hess and Apico LLC each hold 35% interest in the Phu Horm concession; other consortium members are PTT Exploration & Production PCL 20%, and ExxonMobil E&P Khorat Inc. 10%. ✦

Processing — *Quick Takes*

Borouge lets contract for ethylene cracker

Plastics company Borouge has signed a $1.3 billion lump-sum, turnkey contract with Germany's Linde Group for the construction of an ethylene cracker—part of a major expansion project at Borouge's production facility in Ruwais, Abu Dhabi.

The 1.5 million tonne/year cracker will triple production capacity at the facility to 2 million tpy of polyolefins. The Borouge project also will include a 752,000 tpy olefins conversion unit, two 800,000 tpy Borstar polypropylene plants, and a 540,000 tpy Borstar enhanced polyethylene plant. Preliminary work is under way and completion is scheduled for 2010.

CPC refinery to add resid desulfurization

Chinese Petroleum Corp. (CPC) will use Chevron Lummus Global (CLG) technology for a resid desulfurization unit at its 200,000 b/cd Taoyuan refinery in Taiwan.

The 70,000 b/sd plant, for which basic design is complete, is scheduled to come on stream in 2010.

CPC's 300,000 b/cd Talin refinery in Kaouhsiung has two CLG resid desulfurization units in operation.

CLG is a 50-50 joint venture of Chevron USA Inc. and ABB Lummus Global. ✦

Transportation — *Quick Takes*

MinnCan oil pipeline project gets PUC approval

Minnesota Pipe Line Co. (MPL), Rosemount, Minn., received approval from the Minnesota Public Utilities Commission to construct its $300 million MinnCan pipeline project (OGJ Online,

Jan. 4, 2006). It will expand MPL's system, which is at capacity, to transport crude from oil sands reserves in Alberta and Saskatchewan to Minnesota over the next decade.

The MinnCan project consists of a 304-mile, 24-in. oil pipeline from Clearbrook, in northwestern Minnesota, to refineries in Minneapolis and St. Paul.

Construction, expected to take 8 months, will begin this summer. The pipeline, which will have a design capacity of 60,000-165,000 b/d, should be fully operational in 2008.

The system will originate at the existing interconnection between MPL's pipeline system and Enbridge Energy's pipeline system at Clearbrook in Clearwater County. It will pass through 13 counties, with the northernmost 119 miles constructed along existing MPL pipeline right-of-way, except for a 7-mile greenfield route around Staples, Minn. Near Cushing, in Morrison County, the route will diverge from the existing pipeline corridor and extend for 176 miles generally west and south of the Twin Cities metropolitan area.

The project terminates at the Flint Hills Resources refinery at Rosemount in Dakota County. The terminus will provide a direct interconnection with the refinery and with the Marathon Petroleum Co. St. Paul Park refinery through existing pipeline facilities.

Two pump stations are planned, one at the Clearbrook station and another at a midpoint pump station in Morrison County near Upsala. MPL Co. is owned by Marathon Pipe Line LLC, Flint Hills Resources, and TROF Inc.

UK approves National Grid to build major line

National Grid, operator of the UK's gas network, will build a 196-km, 1,220-mm natural gas pipeline from Felindre, near Swansea in west England to Tirley in Gloucestershire, subject to strict UK environmental conditions. The pipeline is an important component in delivering gas from two proposed LNG regasification terminals in Milford Haven, Wales, which are expected to provide 20% of the UK's gas needs when completed.

National Grid will start line construction in late February or early March. Work should be completed in October. Contractors Nacap Land & Marine Joint Venture will construct a 90-km line section from Felindre to Brecon, and Murphy Pipelines Ltd. will install the 106-km section from Brecon to Tirley.

Local environmental groups had protested the pipeline route, particularly the Brecon Beacons National Park Authority (BBNPA), which objected to a 25.7-km section through the park. Local residents also cited concerns that tourists may be dissuaded from coming because of the pipeline's impact.

In announcing approval for the line, Energy Minister Lord Truscott said, "I also have to be mindful of the importance of this project to our national energy needs. As the UK's own reserves of gas decline, there is a need for new infrastructure to connect new sources of imported gas to our homes and industries."

The 4.4 million tonne/year Dragon LNG and the 7 million tonne/year South Hook LNG terminals are under construction in Milford Haven. Dragon is expected to start operations by yearend and South Hook by first quarter 2008.

A BBNPA spokeswoman told OGJ it was disappointed by the UK Department for Trade and Industry's decision to permit National Grid to forge ahead with the pipeline. Now 33.7 km of the pipeline will go through the park. She said BBNPA will appoint two officers to monitor construction and ensure that minimum environmental damage occurs. Under special circumstances, these officers could stop work if they find breaches of environmental regulations.

Equatorial Guinea LNG seeks Zafiro gas as feed

Equatorial Guinea LNG (EG LNG) is looking to use gas from Zafiro oil field, operated by ExxonMobil Corp., as possible feed gas for its liquefaction plant, said Steve Ollerearnshaw, EG LNG managing director, at the International Petroleum Week conference in London Feb. 16.

Currently 150 MMcfd of gas from Zafiro field is flared. EG LNG is in discussions with ExxonMobil to see whether it would be feasible to bring gas for its proposed second LNG train, Ollerearnshaw said. "It would need a pipeline and compression to make it work," he added. Zafiro, which produces more than 270,000 b/d, is the biggest oil field in Equatorial Guinea.

EG LNG has contracted Bechtel Corp. to investigate the feasibility of adding a second 4.4 million tonne/year train. The work is scheduled for completion by the end of the first quarter, and EG LNG shareholders are expected to make a final investment decision by late 2007 or early 2008.

Ollerearnshaw said discussions are under way among Nigeria, Cameroon, and Equatorial Guinea to explore providing gas to EG LNG.

"We believe there is a very sound economic basis for Train 2 at EG LNG," he added, "and we see a long-term potential for up to 20 million tonnes in Equatorial Guinea."

EG LNG will join the club of Atlantic Basin LNG suppliers later, with first LNG production from its initial 3.4 million tonnes/year train due in the summer. Gas for the plant will come from Alba field. BG Group is expected to deliver the volumes to the Lake Charles, La., regasification terminal in the US, but Ollerearnshaw said that BG Group has destination flexibility in its contract.

EG LNG is situated on Bioko Island in Equatorial Guinea (OGJ, Sept. 4, 2006, Newsletter)

Chevron's Casotte LNG terminal gets FERC OK

Chevron Corp. has received approval from the US Federal Energy Regulatory Commission to build the Casotte Landing regasification facility next to the company's 325,000 b/cd Pascagoula refinery in Jackson County, Miss.

The proposed project would process LNG for distribution to Mississippi, Florida, and the US Northeast. The facility would have a nominal processing capacity of 1.3 bcfd of gas.

Chevron also has reserved 1 bcfd of regasification capacity at Cheniere's Sabine Pass LNG receiving terminal in southwestern Louisiana. Construction at this facility is about 55% complete and the terminal is scheduled to start operations in second quarter 2008. Chevron's commitment begins mid-2009.

Both the Sabine Pass capacity and the Casotte Landing facility can be integrated into Chevron's US Gulf Coast pipeline, storage, and terminal infrastructure. ✦

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Letters

Russian gas

I'd like to point out two small inaccuracies in a very good survey by David Wood in "Part 1: Russia seeks global influence by exploiting energy geopolitics" (OGJ, Feb. 12, 2007, p. 20). First, in the dark days of 1998 the European price of Russian gas was less than one quarter of what it is today. Second, according to financial reports of Gazprom, gas sales to Russian consumers were profitable in 2004 and 2005. Moreover, domestic sales have a higher profit rate than the one of Gazprom Marketing & Trading Ltd. of the UK.

Mikhail Korchemkin
East European Gas Analysis
Malvern, Pa.

Calendar

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

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2007

FEBRUARY

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.

SPE Reservoir Simulation Symposium, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. Feb. 27-Mar. 1.

International Symposium on Oilfield Chemistry, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Feb. 28-Mar. 2.

MARCH

Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-6.

Gas Arabia International Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 5-7.

SPE E&P Environmental and Safety Conference, Galveston, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 5-7.

International Pump Users Symposium, Houston, (979) 845-7417, (979)

847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

Purvin & Gertz International LPG Seminar, Houston, (713) 236-0318 x229, (713) 331 4000 (fax), website: www.purvingertz.com. 5-8.

African Refiners Week, Cape Town, +44 (0)20 7343 0014, +44 (0)20 7343 0015 (fax), website: www.afrra.org. 5-9.

Power-Gen Renewable Energy & Fuel Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 6-8.

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632 772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

✦LNG Conference & Workshop, San Antonio, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), website: www.thecwcgroup.com. 7-9.

Plant Maintenance, Tooling & Safety Equipment, Technology & Service Conference, Bankok, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: rowen@oesallworld.com, website: www.allworldexhibitions.com.8-10.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 11-14.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, e-mail: Jennifer.OReilly@nace.org, website: www.nace.org/nace/content/conferences/c2007/welcome.asp. 11-15.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-14.

China Offshore Expo, Tianjin, 84 8 9634388, 84 8 9635112 (fax), e-mail: cp-info@hcm.vnn.vn, website: www.cpexhibition.com. 15-17.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 18-20.

SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-21.

ARTC Refining & Petrochemical Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: owaconference@pennwell.com, website: www.offshorewestafrica.com. 20-22.

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase, Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 22-23.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 25-27.

American Chemical Society National Meeting & Exposition, Chicago, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 25-29.

Turkish Oil & Gas Exhibition and Conference, Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 27-29.

Offshore Mediterranean Conference, Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc.it. 28-30.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 3.

Calendar

APRIL

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-3.

AAPG Annual Convention and Exhibition, Long Beach (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 1-4.

PIRA Natural Gas and LNG Markets Conference, Houston, 212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

China International Oil & Gas Conference, Beijing, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 3-4.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 3-4.

IADC Environmental Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 3-4.

Instrumentation Systems Automation Show & Conference, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

SPE Digital Energy Conference and Exhibition, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-12.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, e-mail: blaine@entelec.org, website: www.entelec.org. 11-13.

Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 11-13.

Molecular Structure of Heavy Oils and Coal Liquefaction Products International Conference, Lyon, +33 1 47 52 67 13, +33 1 47 52 70 96 (fax), e-mail: frederique.leandri@ifp.fr, website: www.events.ifp.fr. 12-13.

Middle East Petroleum & Gas Conference, Dubai, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 15-17.

SPE Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-18.

Society of Petrophysicists and Well Log Analysts (SPWLA) Middle East Regional Symposium, Abu Dhabi, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 15-19.

International Pipeline Conference & Exhibition, Moscow, +43 1 402 89 54 12, +43 1 402 89 54 54 (fax), e-mail: pipeline@msi-fairs.com, website: www.msi-fairs.com. 16-17.

Russia & CIS Refining & Petrochemicals Equipment Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 16-17.

API Spring Refining and Equipment Standards Meeting, Seattle, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 16-18.

ERTC Coking and Gasification Conference, Paris, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 16-18.

SPE Rocky Mountain Oil & Gas Technology Symposium, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-18.

Pipeline Technology Conference & Exhibition, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), e-mail: info@messe.de, website: www.hannovermesse.de. 16-20.

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OPEC, markets evolve

Bob Tippee
Editor

How the Organization of Petroleum Exporting Countries perceives oil markets affects anyone who produces, processes, transports, or uses oil. Like the markets themselves, OPEC's perceptions have evolved.

In the early 1990s, OPEC was wary of the markets that had developed over the prior decade for agreements to receive or deliver physical quantities of oil, or to buy or sell physical quantities, at some time other than the present.

These so-called paper markets emerged after spot trading began to grow at the expense of the long-term contracts that dominated oil markets until the price leaps of the 1970s. By allowing money and oil to change hands at different times, paper instruments such as futures contracts let buyers and sellers of oil hedge their risks of harmful future price movements. And they let investors assume those risks in the hope of profiting from future price movements—to speculate.

OPEC's discomfort

OPEC's discomfort related to speculation. Some of its members had a cultural aversion to anything other than direct sales between themselves and ultimate consumers of the oil they consider a divine blessing. In the early 1990s, too, some OPEC members no doubt resented the speculative profits that followed so soon their own failure to force up prices with production control.

In 1997, therefore, it was easy for OPEC to ignore financial signals, to dismiss forward price patterns of the paper market as evidence of speculative mischief, and to raise production just as demand was contracting because of an Asian financial crisis. By the next year, oil prices had collapsed.

Since then, OPEC has been more attentive to paper markets. If not always accurate—no one can predict oil markets—it has been much more anticipatory with its quota decisions than it was before.

Now the group has chimed in on a question that has rumbled around the oil industry for years: To what extent do financial markets influence the price of oil? The study that conveys the answer, from the OPEC Secretariat's Petroleum Market Analysis Department, reveals much about market perceptions of the world's most important collection of producers.

Especially interesting is the study's view of how the oil market has changed.

In the 1990s, the study says, the market consisted mainly of producers, refiners, industrial oil users, and speculators. Spare production capacity among OPEC members provided a cushion against demand shocks, and downstream capacity was large enough to limit upward swings in crude and product prices. The dominant price pattern was backwardation—with immediate prices higher than prices in distant months. Trading was concentrated in near months.

"Use of oil and commodities as a distinct asset class in private and institutional funds was very limited," the study says of this period. Investors made oil plays through equity in oil companies. "Investment banks, CTAs [commodity trade advisors], and trading companies had relatively small financial exposure to oil."

Since 2000, that direct investment exposure to oil has grown, especially from the activity of investment banks, pension funds, and index and hedge funds. With more money being invested by more types of investors, futures markets gained influence over the price of crude. Paper markets became not just a hedge device but "both investment and hedge tools."

In this new structure, the financial market "expresses its opinion of the future course of prices through position changes and higher volumes of futures and options trade," the study says. So expectations and uncertainty about the future are "discounted into prompt prices more quickly and more forcefully than in the past." It adds, "There is more transparency, but there is also more volatility."

While these changes were in progress, global capacities to produce and refine crude oil were shrinking.

"This development reduced the cushion of supply security and the risk cover on sharp upside price movements, luring both paper hedge and speculative demand into the oil market," the study says.

Physical factors

Some observers blame this movement largely for the increases in oil prices since 2002. The OPEC study notes—and voices agreement with—the alternative view emphasizing physical changes in supply and demand.

Its conclusions: physical factors rather than speculation are the main reasons for price increases since 2002. But speculation "has magnified price oscillations" and contributed to volatility.

Economists will debate validity of OPEC's conclusions. What's important to the oil industry is that the group no longer sees risk-absorbing speculators as wholly alien to petroleum markets. ✦

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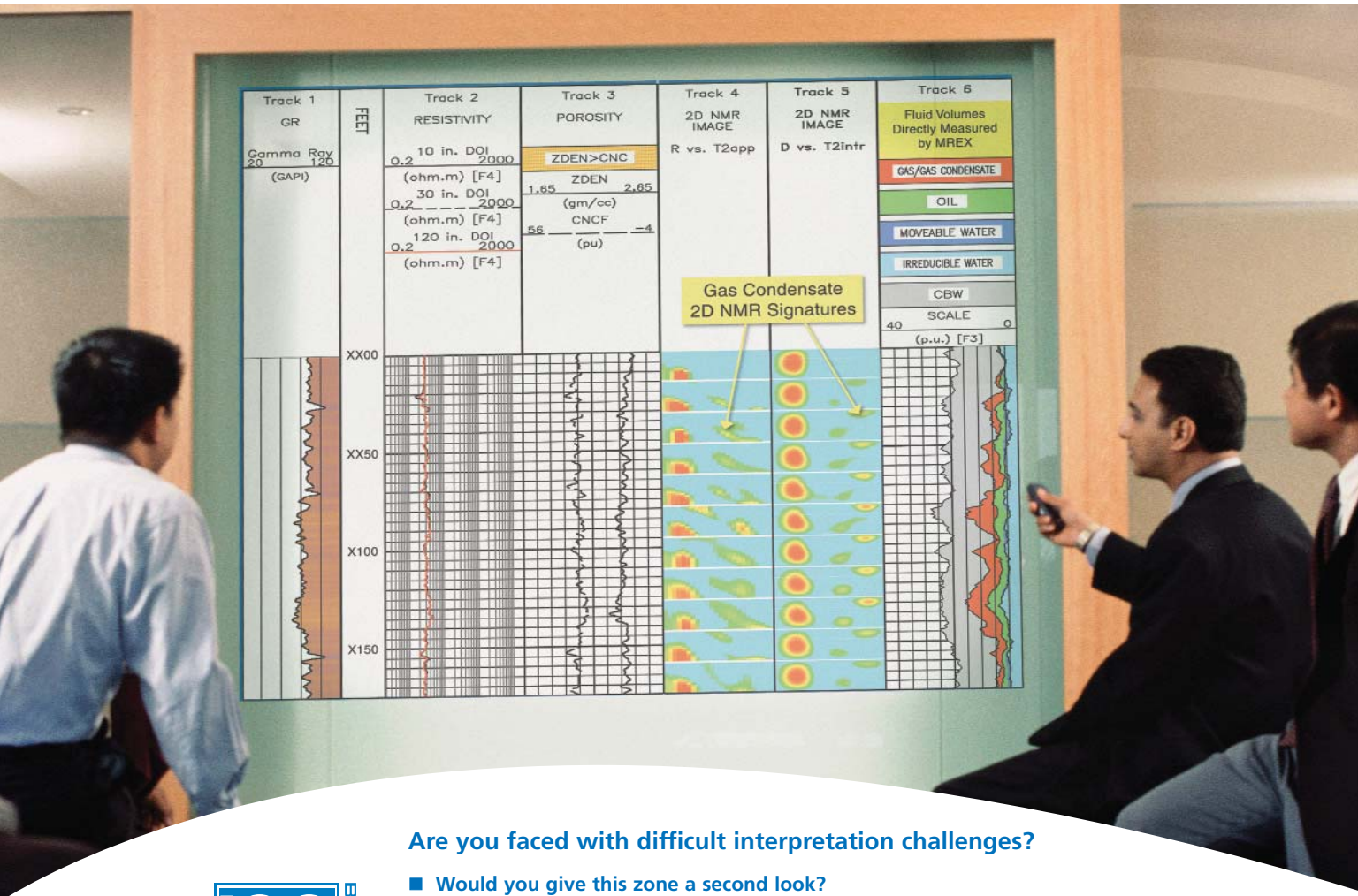

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Editorial

Accommodating prosperity

A global-warming response that accommodates prosperity should have more appeal than one that promises stagnation. So why doesn't the Asia Pacific Partnership on Development and Climate receive more attention?

Signed in 2005 by India, China, South Korea, Japan, Australia, and the US, the partnership emphasizes markets and technology in pursuit of economic growth and environmental improvement for developing countries. Because it relies on voluntary action and innovation instead of mandates, backers of the rival Kyoto Protocol have dismissed it as unsubstantial. Yet their own approach is foundering as one ratifying country after another falls behind in its efforts to meet targets for emissions of greenhouse gases.

Agenda forming

Where Kyoto puts emission targets ahead of economic consequences, the Asia Pacific Partnership looks for ways to integrate environmental, technical, and economic progress. That it did not lead with a political agenda is in fact a sign of seriousness. And now an agenda is coming into view.

A paper written for the International Council for Capital Formation (ICCF) points to basic economic reform in developing countries as essential to climate-change response. "Institutional reform is a critical issue for the partnership because the lack of a market-oriented investment climate is a principal obstacle to reducing greenhouse-gas emissions in China, India, and other Asian economies," write W. David Montgomery, vice-president, and Sugandha D. Tuladhar, associate principal, in the Washington, DC, office of CRA International. The ICCF has been a prominent voice warning of the heavy costs of Kyoto compliance.

"The same institutional factors that are prerequisites for sustained economic growth—laws protecting property and contracts, fair and efficient administration of justice, reduction of the government's role in the economy, minimization of regulatory burdens and corruption, and openness to foreign investment—are closely associated with efficient use of energy and low greenhouse-gas emissions per unit of output," Montgomery and Tuladhar write. Compared with other members of the partnership, they say, China and India have far higher energy use and greenhouse-gas emissions per dollar of output—rates called energy and emission intensities. The countries also have relatively low economic freedom. An analysis by the authors of 91 countries shows a strong relationship between economic freedom and the improvement in energy intensity that accompanies growth.

Montgomery and Tuladhar see opportunity in the high-emissions energy technology of developing countries. While China's emissions intensity is improving, its installed capital equipment produces greenhouse gases at about four times the rate of US equipment. India's emissions intensity isn't improving, and its new investments involve technology with twice the emissions intensity of new US investments.

"Our calculations show that emission reductions can be achieved by closing the technology gap," the authors write. "The potential from bringing the emissions intensity of developing countries up to that currently associated with new investment in the United States is comparable to what could be achieved by the Kyoto Protocol."

Montgomery and Tuladhar urge Australia, South Korea, Japan, and the US to fund research into topics such as the investment climates and energy patterns of China and India. They recommend negotiations, through a system of task forces that the partnership already has in place, to identify institutional reforms and investments with the potential for lowering emissions. They say the consequent investments could reward India and China for institutional reform.

Hazy recommendations

These recommendations remain hazy—no doubt too hazy for the noisy crowd that demands immediate action, even if it's wrong, on global warming. But they have a chance to develop into negotiated, voluntary measures that can work. This can't be said for the act-now, mandatory approach that produced the Kyoto treaty.

Kyoto relies on a futile political proposition: certain sacrifice for uncertain benefit. Real progress on the mitigation of climate change depends on reduced emission rates accomplished along with, rather than at the expense of, economic growth. As the Montgomery and Tuladhar paper implies, in fact, growth—and the access it provides to efficient technology—can be a precursor to emission cuts. The study, like the Asia Pacific Partnership, deserves more attention than it so far has received. ✦

Fischer-Tropsch oil-from-coal promising as transport fuel

Ken K. Robinson
David F. Tatterson
Mega-Carbon Co.
St. Charles, Ill.

As crude oil prices rose above $50/bbl last year, interest revived in the use of Fischer-Tropsch (F-T) technology to produce transportation fuels from coal.

Developed during World War II, the F-T process in recent years has moved into commercial-scale use in gas-to-liquids projects around the world.

While application of the technology to coal is economically more challenging than it is for natural gas, its possibility raises hope globally and especially in the US for development of fuel supply from an abundant and secure domestic hydrocarbon resource. As part of modern integration schemes such as those described in this article, indirect liquefaction resolves environmental problems associated with traditional coal combustion.

Coal, an extremely large and significant energy resource, has huge potential as a source of clean liquid hydrocarbons for coal-rich nations, including the US, which has more than one-fourth of the world's coal supply.

With newer technologies such as integrated gasification combined cycle (IGCC), coal conversion is an environmentally friendly process. Pollutants—mercury, sulfur oxides (SO_x), and nitrogen oxide gases (NO_x)—are essentially eliminated because coal gasification instead makes hydrogen sulfide and ammonia, which can easily be removed in gas scrubbers. Carbon dioxide, considered a greenhouse gas, can also be captured and sequestered, and can even provide a significant income stream if oil fields are nearby and responsive to CO_2 flooding.

This study examines coal conversion to liquid hydrocarbons and electric power generation, using IGCC as the basis for gasification. The syngas is converted to liquid hydrocarbons using F-T technology. There are several scenarios where this commercially proven technology offers attractive economics.

Two significantly different coals were investigated for conversion to liquid hydrocarbons and electric power generation using "green" technology. Furthermore, an "ultragreen" case was developed in which the CO_2 emissions are practically eliminated by shifting all of the carbon monoxide to a hydrogen-rich gas before the synthesis gas feed goes to the power plant. The hydrogen-rich gas is then burned in the combustion turbine of the IGCC plant.

The coals studied were a low-sulfur Western subbituminous coal typified by Montana Rosebud and a high-sulfur Eastern coal typified by Illinois No. 6 coal. The Montana Rosebud coal results in the best economics, partly because of its cheaper cost, but more significantly, the CO_2 can be utilized in nearby oil fields.

CO_2 as a revenue stream to be sold for enhanced oil recovery (EOR) looks likely for Montana coal because of nearby oil fields in the Williston basin. However, the potential revenue stream remains questionable for an eastern plant location, as the location and responsiveness of local oil fields need to

be established.

The study found the following return on investment (ROI) scenarios and economics, based on discounted ROI:

1. Western coal to liquid transportation fuels, 14% ROI.
2. Western coal to electricity via IGCC, 12% ROI.
3. Western coal to liquid transportation fuels and electricity, 15% ROI.
4. Western coal to liquid transportation fuels and electricity utilizing the ultragreen mode for making electricity, 16% ROI.
5. Eastern coal to liquid transportation fuels and electricity, 9% ROI.
6. Eastern coal to liquid transportation fuels and electricity utilizing the ultragreen mode for making electricity, 12% ROI.

The technology is commercially proven to make coal an important and significant source of liquid hydrocarbons. Large plants are already operating in South Africa. Coal especially should be part of the US overall alternative energy picture and recognized as on a par with other, more-frequently touted alternative energy sources such as biomass, hydrogen, and wind power.

Coal-rich US

Although the US has only 2% of global oil reserves, it has 27% of the coal reserves and is frequently referred to as "the Saudi Arabia of coal" (Fig. 1). Table 1 shows the top three coal-rich states and their estimated reserves. Although coal is not the single answer to broadening the US energy portfolio, it certainly is abundant enough to have an important positive impact on fuel supply because the US depends almost entirely on crude oil for its transportation fuels. This reliance, particularly on imported crude oil, has caused problems for the US. Not only does it affect it economically in its balance of trade but, more significantly, contributes to major foreign policy issues between the US and countries that exploit their oil power.

After taking into account process heat and electric power generation, about 2 bbl of liquids/short ton of coal can be produced using a coal gasification process followed by F-T synthesis. Therefore the combined total coal-derived liquids of just the above three states, when based on the more conservative estimated recoverable reserves, is 309.6 billion bbl of oil. If total imported oil is 7.3 million b/d, then these three states could supply all of the US imported oil for around 70 years. If the US relied on coal for all of its oil consumption of 20 million b/d, then it would have enough coal in these three states alone to run the US for 41 years. Obviously coal cannot be the primary source of liquid fuels for the US, but these calculations certainly demonstrate how vast US coal reserves are and that they are positioned to make a significant contribution.

The National Coal Council is pushing for government incentives to help generate some 2.6 million b/d of liquid fuel from coal by 2025. This would satisfy about 10% of the US's total demand and reduce imported oil by 25%. The coal reserves and the technology are available to meet this goal. Only the economics remain in question

Coal gasification followed by F-T synthesis is proven commercial technology. Sasol Ltd. of South Africa is making about 160,000 b/d of liquid product from its coal reserves, and currently is offering its technology to license.[1] While Sasol would charge a licensing fee, it is more interested in an equity position in the licensed projects—as much as 50%.

China is building a coal-to-liquids facility to produce about 200,000 b/d with its own direct liquefaction technology but also wants to use Sasol indirect liquefaction technology for an additional 80,000 b/d.[2]

Although direct liquefaction processes are more energy-efficient than F-T, they are difficult to run and keep on stream. From the point of reliability, indirect liquefaction wins hands down. China's direct liquefaction technology will probably cause it problems later, as the coal ash creates huge erosion problems that eat away valves, and staying in donor solvent balance is a real trick.

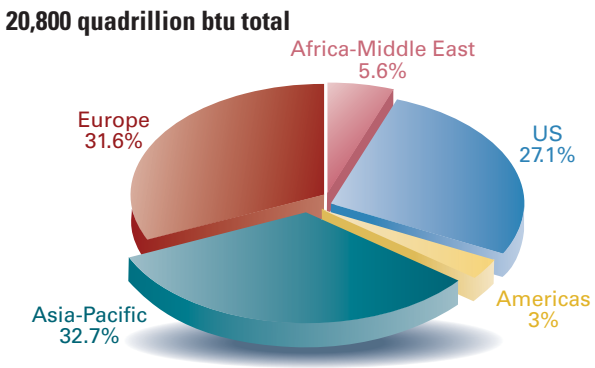
The need for strategy

In 2003, the US consumed 20 million b/d of crude oil, with about 55% imported from foreign countries. The greatest suppliers of oil and oil products to the US are Canada, Saudi Arabia, Mexico, Venezuela, and Nigeria, in that order.

Several of these areas have experienced instability in recent years. Volatility anywhere in the oil patch drives up the price of crude from all sources. These recent instabilities have under-

World coal reserves

Fig. 1



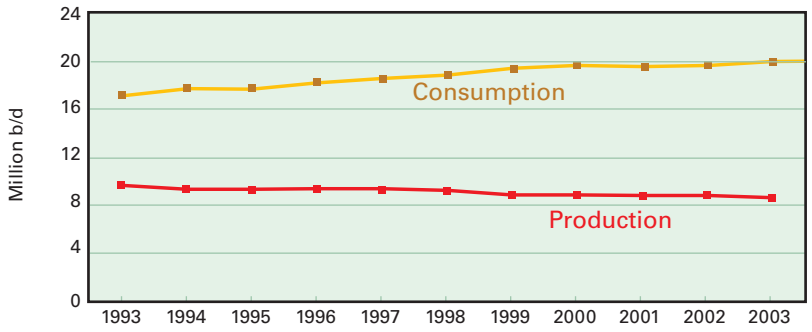
Demonstrated recoverable US coal reserves

Table 1

Top three states	Demonstrated reserve base	Estimated recoverable reserves	Reserves at active mines
	Million tons		
Montana	119,280	74,989	1,140
Illinois	104,529	38,019	796
Wyoming	64,325	41,804	7,053

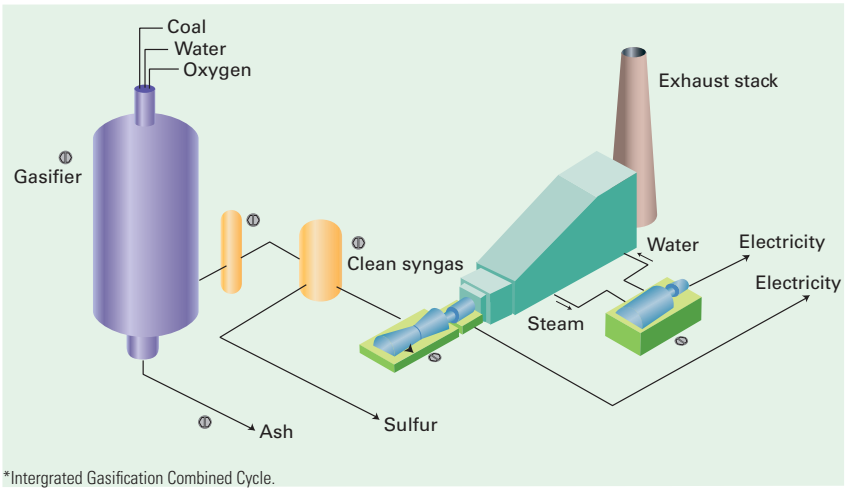
US CRUDE OIL PRODUCTION, CONSUMPTION

Fig. 2



IGCC* FOR ELECTRIC POWER GENERATION

Fig. 3



*Intergrated Gasification Combined Cycle.

lined the need for the US to develop more domestic resources. Fig. 2 summarizes how US crude oil consumption and production have trended during 1993-2003.

One continuing trend observed is that US crude consumption continues to increase while domestic production decreases.

Current initiatives

Currently the US Department of Energy is focusing its alternative transportation fuel efforts mainly on hydrogen and biomass as measured by the amount of funding allocated in these areas.

All hydrogen generated today is produced from a hydrocarbon source, generally natural gas. It could be made electrolytically, and if hydroelectric or nuclear power were used, it could be classified a green fuel. However, barring the development of surplus cheap nuclear power, an economically viable source of hydrogen is unlikely in the near future. In addition, the infrastructure to distribute hydrogen to fueling locations does not exist. Onboard vehicle storage capabilities would limit the range of any vehicle powered by hydrogen, although some attempts to concentrate it via metal hydrides have met with limited success. Hydrogen as a transportation fuel faces many challenges before it can significantly contribute to the transportation fuel mix.

The most significant biomass fuel in the marketplace today is ethanol produced from corn. US production is 4 billion gal/year. The debate over whether a gallon of ethanol requires more energy to produce than it contains has continued over the last 2 decades.

MIT chemistry professor John Deutch, a former director of energy research, undersecretary of energy in the Jimmy Carter administration, and former director of the Central Intelligence Agency, recently commented in the Wall Street Journal on the "biomass movement:" "Cultivation of corn is highly energy-intensive, and a significant amount of oil and natural gas is used in growing, fertilizing, and harvesting it. Moreover, there is a substantial energy requirement—much of it supplied by diesel or natural gas—for the fermentation and distillation process that converts corn to ethanol. These petroleum inputs must be subtracted when calculating the net amount of oil that is reduced by the use of ethanol in gasoline.

Others estimate that ethanol contains plus or minus 25% of the energy required for manufacture. But the energy issue is largely academic, as the economics of ethanol production depend on a government subsidy to make it a viable fuel. The current subsidy is $0.51/gal. The other source of biomass is cellulosic material such as the much-touted switch grass and agricultural by-products like corn stover and straw. However, cellulose must first be converted into sugar and then into ethanol with advanced enzyme technology. Genencor and Novozymes have made some headway. This technology, however, is still in the research and development stage.

Greenhouse emissions

Another important issue faced today is that of greenhouse emissions worldwide, notably CO_2. Coal historically has been used to generate electric power, and in the US represents over half of all electric power generation. As stated in C&E News, "The US, like the rest of the world, has a coal problem: There is a lot of it and it is cheap, but it is dirty. Coal-fired power plants are responsible

Military testing Fischer-Tropsch fuels

Paula Dittrick
Senior Staff Writer

The US Department of Defense is examining the possible role of Fischer-Tropsch fuels for military vehicles, starting with its aircraft.

The Defense Energy Support Center of Fort Belvoir, Va., which oversees fuel purchases for DOD, has asked companies to submit proposals regarding the availability of possible synthetic fuel suppliers for anticipated field tests by the Air Force and Navy.

Last year, the Air Force successfully tested a synthetic fuel in a B-52 bomber. The test flights involved a 50-50 blend of traditional jet fuel and a synthetic liquid made from natural gas using the Fischer-Tropsch process.

William E. Harrison III, the chief of fuels branch propulsion directorate for the Air Force Research Laboratory, said DOD wants to obtain for the military clean fuels that are produced from secure domestic resources.

"It's a 40-year-old airplane with very dirty engines," Harrison said of the B-52, adding that the aircraft was chosen to test new technology fuel because its engine enables convenient comparison of engine performance using different fuels.

The Air Force seeks to replace its commercial airlines Jet-A fuel and its kerosene-based JP-8, which is the equivalent of the Navy's F-76. Both the military and airlines are considering whether alternative fuels could help reduce costs in times of high oil prices.

Speaking in The Woodlands, Tex., last year at a conference on carbon dioxide, Harrison said Fischer-Tropsch fuel produces lower emissions compared with traditional fossil-based fuel. Test results indicated the synthetic fuel produced 1.6% fewer CO_2 emissions, 50-90% less particulate matter, and no sulfur.

"CO_2 has got to be part of the strategy," he said. "America's unconventional fuel resources can help bridge the gap to future fuels."

Secure supply

Military preparedness requires secure fuel sources, Harrison said, adding that the military is looking to reduce its dependence on imported crude oil. The Fischer-Tropsch process can use coal, natural gas, or biological matter—all abundant in the US—to make an intermediate synthesis gas (syngas) that is refined into fuel.

Syntroleum Corp. of Tulsa made the synthetic liquid from natural gas for the

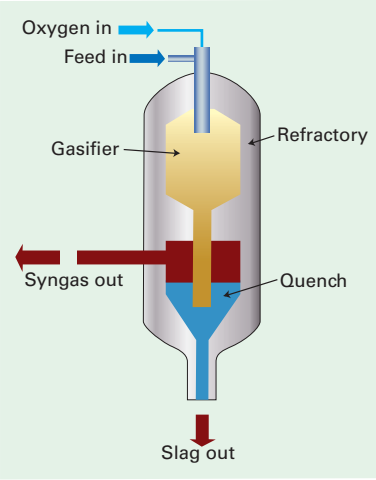
for 60% of US sulfur dioxide emissions, 33% of US mercury emissions, 25% of nitrogen oxide emissions, and more than 33% of the nation's CO_2 emissions."[3]

However, it doesn't have to be that way because IGCC, shown in Fig. 3 for electric power generation, makes coal a very clean fuel with the side benefit of increasing the thermal efficiency from about 33% for conventional coal firing to more than 40% for IGCC. DOE is taking the lead in commercializing IGCC in its Future Gen Project slated for either Illinois or Texas, with two candidate plant sites in each state.

In a typical IGCC plant, coal is first gasified to synthesis gas, hydrogen, and carbon monoxide. The synthesis gas is scrubbed to remove acid gases and mercury. The synthesis gas is then burned in two sets of turbine drivers, first a combustion turbine and then a steam turbine to produce electricity. If the synthesis gas is passed through a water gas shift converter, the CO converts to CO_2. The CO_2 can also be scrubbed, providing a hydrogen-rich steam to the turbines. This scenario is called "ultra-green" because there would be very little CO_2 emitted from the power plant. CO_2 cannot currently be eliminated entirely, as some carbon must be left in the feed to the power plant for flame stability.

The increased cost of IGCC over conventional coal firing is 20-25%.[4] However, when including the benefits of less air pollution and the ability to conveniently capture carbon dioxide emissions, the price difference is not so obvious. Furthermore, if the federal government enacts CO_2 emission controls, they could make conventional coal-fired technology no longer the economic choice. The primary environmental benefit of IGCC is increased energy efficiency and the potential for significantly reduced air pollution. IGCC can be used as a springboard for making liquid hydrocarbons from coal by integrating F-T synthesis with the electric power generation plant.

GE GASIFIER Fig. 4



The run-up in crude prices over the last year to $50-80/bbl has stimulated renewed interest in F-T synthesis. Furthermore, technological improvements in F-T synthesis, such as slurry phase reactors plus tougher environmental standards are pointing to F-T as a promising way to help abundant coal

B-52 test flights. The Air Force eventually wants a synthetic liquid produced from coal.

The Air Force spends more than $10 million/day on fuel, Harrison said, adding that every $10/bbl increase in oil prices means an additional $600 million/year to the Air Force's fuel bill.

"Fischer-Tropsch is not just for the airplane...Fischer-Tropsch is a very fine rocket fuel," he said. "The Air Force and the Department of Defense are serious about alternative fuels."

DOD has looked at the experience of the South African military because Sasol Ltd. has produced synthetic fuel from coal for at least a decade, he noted.

"Actually if you fly in and out of Johannesburg on a commercial airline, you are going to get some fuel that has Fischer-Tropsch [produced fuel] in it," Harrison said.

The US Air Force has 150 different variations of aircraft along with ground support equipment and vehicles, he said. Testing of engines other than the B-52 is planned.

DOD is collaborating with engine manufacturers and is soliciting comment from energy companies about supplying alternative fuels, Harrison said. DOD's goal is to have a single kind of fuel, although it wants to have as many suppliers as possible.

"We want to see diversity of technology," Harrison said. "We don't tell the refiners how to refine it. We tell them the standards. That's the path we are going down. We like to see diversity."

Biofuel

The military also is looking into using vegetable oil from a variety of agricultural feedstocks for making aviation fuel via the Fischer-Tropsch process.

DOD's Defense Advanced Research Projects Agency awarded $5 million to the Energy & Environmental Research Center at the University of North Dakota in Grand Forks for the development and demonstration of a renewable domestic jet fuel.

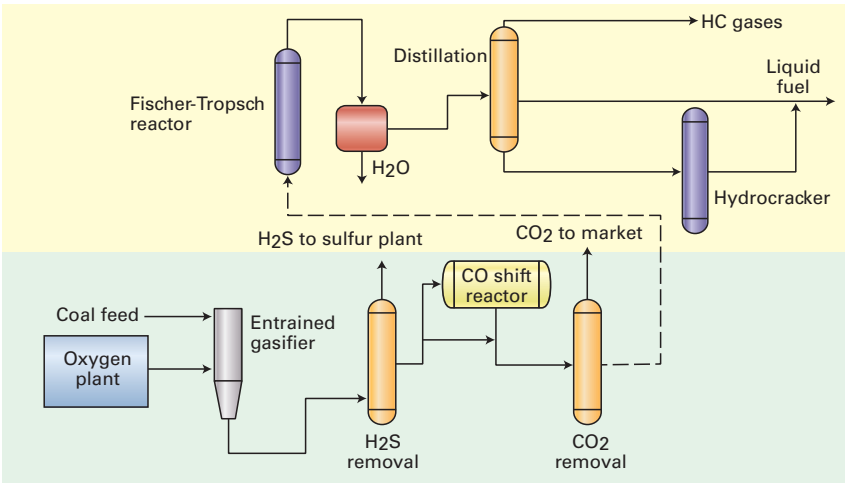
The 18-month project was announced in December 2006. The fuel produced by the EERC would be a candidate with which to replace the traditional JP-8 fuel.

EERC spokesmen said the center will expand its capabilities in tactical fuels and demonstrate how fuels made from crop oil could replace imported oil.

"Our whole approach with this project is to develop an affordable new fuel that can be dropped in to replace the current JP-8 fuel," said Ted Aulich, EERC senior research manager. "This replacement will allow an easy transition from a petroleum-based fuel to a 100% domestic renewable fuel."

COAL-TO-LIQUID TRANSPORTATION

Fig. 5



increase its contribution to total energy supply.

In addition to removing other pollutants from power generation, IGCC technology also is capable of capturing CO_2 that can be sequestered. DOE is quietly funding CO_2 sequestration partnerships around the country, such as the Blue Sky Sequestration Partnership in Montana.

Thus, IGCC technology, combined with CO_2 capture, can provide a road to increased domestic crude production, provided the regional oil fields are receptive to CO_2 flooding and the CO_2 is available in sufficient quantities. CO_2 captured from the Great Plains plant in North Dakota, is used in this manner. "Regional" is defined as a radius of 400-500 miles of the plant. CO_2 currently is piped from southwest Colorado (Cortez) into the Texas panhandle—a distance of 450 miles. Thus, the CO_2 situation today differs considerably from that during the energy crisis of the 1970s and 1980s, when CO_2 was simply emitted to the atmosphere. Today CO_2 can be a viable product in its own right. Tomorrow, it may be classified as a pollutant, making its capture mandatory.

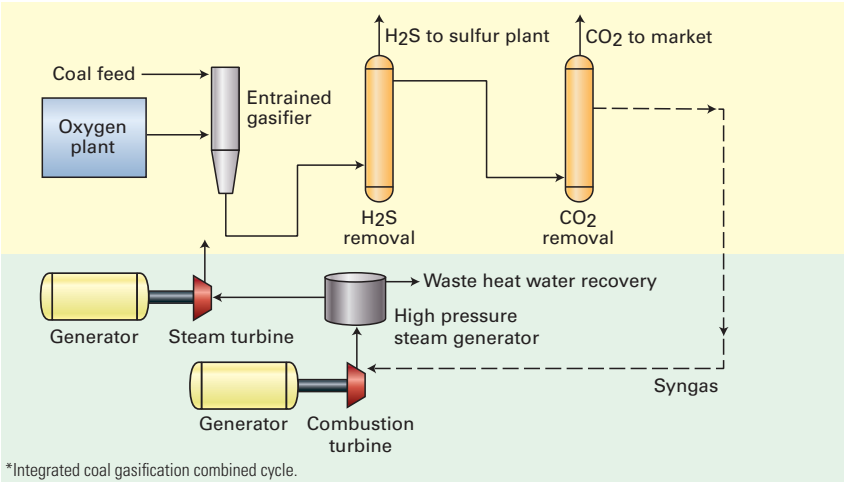
The sale of CO_2 in combination with power generation and the production of liquid transportation fuels from coal is the primary focus of this paper.

Fischer-Tropsch projects

Table 2 lists worldwide coal-based F-T projects that are existing, proposed, or in development. Three F-T plants based on coal are in operation: Sasol I, Sasol II, and Sasol III, all in South Africa. Originally they were developed more

COAL-TO-ELECTRICITY BY ICGC*

Fig. 6



*Integrated coal gasification combined cycle.

for political considerations than for economics. The world community refused to export oil to South Africa because of the government's apartheid policy. Since apartheid ended, Sasol has licensed its F-T technology mainly for conversion of natural gas to transportation liquids. It most recently began converting gas to synthetic crude at the Oryx plant in Qatar, which in March will begin converting 330 MMcfd of lean gas from Qatar's vast North gas field into products for global markets.

The recent escalation of crude oil prices has stimulated interest in additional coal-based F-T projects, notably in China and the US. Two commercial projects are moving forward in the US: Rentech Midwest Energy is converting an ammonia plant in Iowa using gas to make F-T liquids from Illinois coal, and WMPI Inc. in Pennsylvania is converting coal tailings to liquid fuels. Most recently, Montana Gov. Brian Schweitzer announced in fall 2006 that DKRW Advanced Fuels LLC will be building a coal-to-liquids plant in Montana producing 22,000 b/d of diesel fuel and about 150 Mw of electricity; completion is expected in 5 years.

Economics

Ultimately, it is economics that drives decisions relative to energy needs and whether coal conversion technologies can compete economically with crude oil. This article uses a case study approach to determine the economics of power generation, transportation fuels, and CO_2 from coal. It specifies the commercial process, establishes the material balances, estimates the capital investment, and finally establishes the discounted rate of return on investment. It covers only green (capture of CO_2 after gasification) or ultragreen (conversion of CO in the power plant feed to hydrogen-rich gas with water gas shift reactor, followed by CO_2 capture) technology where CO_2 emissions are captured and sequestered.

The six cases demonstrate the impact of key parameters, such as coal type (Eastern vs. Western), the coproduction of both electricity and liquid transportation fuels, and the use of CO_2 for enhanced oil recovery (EOR) in nearby oil fields. All of these cases use only commercial proven technologies.

Four of the cases (1-4) are based on use of Montana Rosebud subbituminous coal, and two cases (5-6) are based on use of Illinois No. 6 bituminous coal:

1. Coal to liquid transportation fuels, using F-T synthesis.
2. Coal to electric power, using IGCC.
3. Coal to both liquid transportation fuels and electric power.
4. Ultragreen technology to eliminate essentially all CO_2 emissions from the IGCC plant, using hydrogen-rich gas for the combustion turbine.
5. Same as Case 3 but substituting high-sulfur, low-moisture Eastern coals feed instead of low-sulfur Western coal.
6. Eastern high-sulfur, low-moisture coal with additional shift conversion to run in ultragreen mode with hydrogen-rich gas for combustion turbine

These cases are summarized in Table 3 with the products, investment, and return on investment (ROI). For this analysis, the price of oil was set at $60/bbl (conservatively equivalent to $1.80/gal for zero-sulfur diesel fuel), electricity at $35/Mw-hr, and CO_2 at $1/Mscf to establish the cash flow.

The discounted cash flow (DCF) rate of return on investment is very attractive for Cases 1, 3, and 4, all based on using Western subbituminous coal, Montana Rosebud. Cases 5 and 6, based on bituminous Illinois 6 coal, have a lower ROI for

Using Sasol Ltd.'s Fischer-Tropsch process, the Oryx gas-to-liquids plant in Qatar, owned by Qatar Petroleum Co. and Sasol Ltd., will begin converting lean gas from Qatar's giant North field to products beginning in March. Photo courtesy of Sasol.

two primary reasons. First, the Illinois coal is more expensive at $45/ton vs. $12/ton for Montana coal. Second, the Illinois coal has less moisture and gasifies more efficiently, producing less CO_2. Hence there is less CO_2 to sell for EOR, and this reduces the ROI in Cases 5 and 6.

Case 3 using Montana coal is a direct comparison to Case 5 using Illinois coal and the ROI drops to 9% with Illinois coal from 15% with the Montana coal, while Case 6 is a direct comparison to Case 4, and the return drops similarly to 12% from 16%. Although it is easy to justify the CO_2 revenue stream for Montana coal because there are nearby oil fields that will benefit from EOR, it is less clear whether the same scenario could be found in the state of Illinois.[5] Consequently, the return on Cases 5 and 6 for Illinois 6 coal might actually be lower if there is no market for the CO_2 produced and producers must simply sequester it and inject it into the ground.

Case analyses

Case 1. Developing liquid transportation fuels from Western coal using F-T synthesis has several commercial advantages:

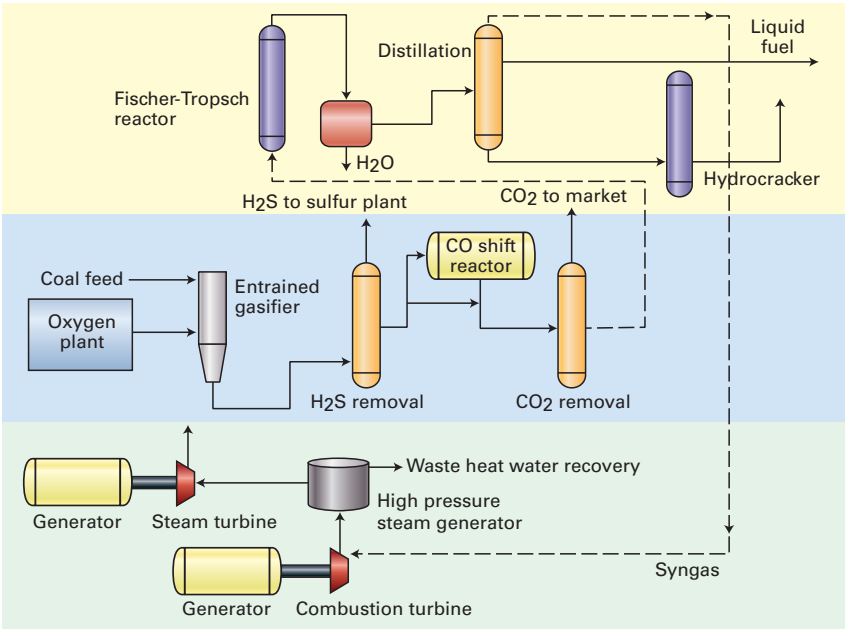
- It uses cheap Western coal.
- It employs a once-through F-T synthesis operation.
- CO_2 is sold for EOR in nearby oil fields.

There also are environmental advantages for this scenario:

- All CO_2 is captured.

COAL-TO-ELECTRIC-POWER, LIQUID TRANSPORTATION FUELS

Fig. 7



- Sulfur, nitrogen, and mercury are captured in the gas cleanup following gasification.

Montana subbituminous coal is gasified by slurrying in water and then fed with oxygen into an entrained flow gasifier such as the GE gasifier, previously known as the Texaco gasifier (Fig. 4). The gas composition leaving the gasifier includes CO, hydrogen (H), CO_2, water (H_2O), ammonia, and acid gases (H_2S and COS) and small amounts of methane. For syngas generation, an entrained flow gasifier, like the GE version or Destec gasification process (formerly Dow's; now ConocoPhillips's), is preferred because it operates at high temperature and makes very little methane.

In this process, illustrated by Fig. 5, the water is condensed out, and acid gases, including CO_2, COS, and H_2S are removed separately with a gas scrubbing system such as Selexol. The hydrogen-carbon monoxide ratio is then adjusted by flowing part of the scrubbed gas through a CO shift converter to get a 2.1 ratio of H_2 to CO. The syngas is then fed into an F-T reactor using a "once-through" flow through, rather than recycling the unconverted syngas and methane due to the high single pass conversion (greater than 90%) that is achieved. A once-through opera-

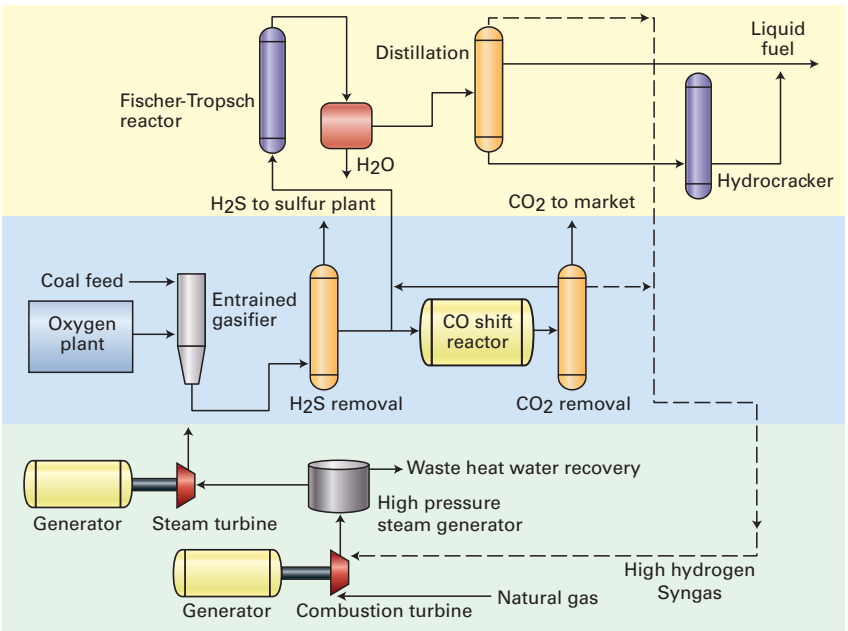
GLOBAL FISCHER-TROPSCH PROJECTS BASED ON COAL

Table 2

Project	Location	Status	Gasification technology	Coal feed	FT synthesis	Capacity, b/d
Sasol I	South Africa	Operating	Lurgi dry ash	Subbituminous	Arge fixed bed	5,000
Sasol II	South Africa	Operating	Lurgi dry ash	Subbituminous	Circulating fluid bed	37,000
Sasol III	South Africa	Operating	Lurgi dry ash	Subbituminous	Circulating fluid bed	40,000
WMPI Inc.-DOE	Gilberton, Pa.	Development	Shell	Anthracite culm (tailings)	Sasol slurry	5,000
Rentech Energy-Midwest	East Dubuque, Iowa	Development	GE	Il 6 and Western coal	Rentech slurry	1,800
DKRW-Wyoming	Medicine Bow, Wyo.	Proposed	GE	Subbituminous	Rentech slurry	11,000
DKRW-Montana	Roundup, Mont.	Proposed	GE	Subbituminous	Rentech slurry	22,000
Rentech PDU	Commerce City, Colo.	Development	GE	Eastern and Western	Rentech slurry	10-15
China Project I, Shenhua Corp.	Shaanxi Province, China	Proposed	N/A	—	Sasol slurry	80,000
China Project II, Shenua Ningxi Coal Ltd.	Ningxia Hui autonomous region, China	Proposed	N/A	—	Sasol slurry	80,000

ULTRAGREEN CASE TO MAKE ELECTRICITY, LIQUID FUELS

Fig. 8



tion eliminates the need for separation equipment and compressors, reducing the capital investment. The unconverted syngas and light ends are burned for plant fuel.

The hydrocarbon yield structure[6] is based on an F-T fixed bed reactor with a cobalt catalyst. The reaction products include a broad spectrum of hydrocarbons ranging from light gases to middle distillates, and finally waxes and water according to the following F-T chemical reaction:

$$16H_2 + 8CO \rightarrow C_8H_{16} + 8H_20 + \text{heat}$$

Sasol's Qatar facility has a more advanced slurry phase reactor. However, the yield structure from that reactor design is not available. Presumably, it is better than fixed-bed yields, and thus these reported liquid yields could be conservative. The reaction products include a broad spectrum of products ranging from light gases to middle distillates, and finally waxes, and water.

Water is separated from the hydrocarbon products in a condenser, and the hydrocarbons are then distilled in a fractionation column. Light gases leave overhead, middle distillates exit the middle of the fractionator, and the heavy waxes leave in the bottoms stream. The waxes are sent to a hydrocracker to reduce the high molecular weight hydrocarbons to light and middle distillate. The distillate produced has zero sulfur and a very high cetane number.

The CO_2 stream is available for sale to oil production facilities. If that is not an option, it can be sequestered for injection into the ground. A recent DOE study by Advanced Resources International shows a strong potential for CO_2 flooding in the Williston basin of Montana.[5] Lookout Butte and Elk basin are two such areas being considered.

Case 2. This illustrates the generation of electric power using IGCC as the basis for gasification. The primary commercial advantage is that IGCC has a higher thermal efficiency than direct coal burning.

There also are several environmental advantages:

- CO_2 from coal gasification is captured.
- All sulfur and nitrogen from coal are captured.
- Some NO_x is emitted from the combustion turbine.
- Mercury from coal is captured.

This case is similar to Case 1 but now no liquid hydrocarbons are made, and instead all of the scrubbed syngas is directed to a power generation cycle (Fig. 6). The coal input is reduced in half because it is necessary to make only 525 Mw of power, as this is a typical size electric power generating facility for IGCC. Because the hydrogen-carbon monoxide ratio is no longer important, the CO shift converter can be eliminated from the process scheme.

More specifically, the unshifted syngas is fed into a combustion turbine that drives one set of electric generators. The hot combustion gas leaving the combustion turbine is then directed into a waste heat boiler to generate superheated steam. This steam is fed into a second set of steam turbines to generate more electricity. This coupling of the gas and steam turbines results in a higher thermal efficiency compared with conventional coal firing. More specifically, the thermal efficiency of IGCC is greater than 40%, whereas direct coal firing is around 33%.

Case 3. Case 3 is conversion of coal to both liquid transportation fuels and electric power. There are a number of commercial advantages to this process:

- Unconverted syngas from the F-T reactor can be burned in the combustion turbine.
- The process can make both liquid fuels and electricity.
- There is higher thermal efficiency from IGCC.

In addition, it has many environmental advantages:

- All CO_2 is captured from the gasification section, but CO_2 is emitted from the combustion turbine.
- All sulfur and nitrogen from the coal are captured.
- A small amount of NO_x is emitted from the combustion turbine.
- Mercury in coal is captured.

Case 3 is a combination of Case 1 and Case 2 using the same amount of Montana coal as Case 1 but splitting the syngas production into two parts,

roughly half for electric power generation, and the other half for production of F-T liquids. The primary coupling of the two processes is with the light gases leaving the F-T section of the plant being fed to the electric power section. Referring to Fig. 7 for Case 3, the process flows have been described previously for the separate parts of the combined process, so no further discussion is necessary here.

CASE STUDY SUMMARY[1]

Table 3

Case[2]	Coal, tons/day	Diesel, b/d	Electricity, Mw	CO_2, MMscfd	Capital investment,[3] billion $	DCF[4] rate of return, %
1	10,773	9,019	—	342	1.300	14
2	5,963	—	525	121	0.785	12
3	10,733	4,428	525	273	1.100	15
4	10,733	4,439	525	387	1.200	16
5	8,000	4,439	525	121	1.125	9
6	8,000	4,349	525	297	1.161	12

[1]Based on oil at $60/bbl, zero sulfur diesel at $1.80/gal, electricity at $35/Mw-hr, CO_2 at $1/Mscf, and a 30 year project life, 20 year straight line depreciation, 35% income taxes, and 4 year construction (10/10/40/40). [2]Cases 1-4 use Montana coal at $12/ton, Cases 5-6 use Illinois coal at $45/ton. [3]Capital estimates are based on a multiclient study from a major US firm for Fischer-Tropsch and on an Electric Power Research Institute study on IGCC for gasification. [4]Discounted cash flow.

MONTANA VS. ILLINOIS COAL

Table 4

	Moisture %	Volatiles %	Fixed carbon	Ash %	Sulfur %
Subbituminous Montana Rosebud	22	30	42	5.4	0.7
Bituminous Illinois No. 6	5	36	49	9.8	3.2

Case 4. In Case 4, ultragreen technology eliminates most CO_2, using hydrogen-rich gas in combustion turbines. This process has five major commercial advantages:

- It produces the highest ROI.
- Unconverted syngas can be burned in the combustion turbine.
- Both liquid fuels and electricity can be made.
- Higher thermal efficiency is derived from IGCC.
- Combustion turbine burns a hydrogen-rich gas, so little CO_2 is emitted.

There also are a number of environmental advantages of this method:

- CO_2 emissions are extremely low.
- All sulfur and nitrogen from the coal are captured.
- A small amount of NO_x is emitted from the combustion turbine.
- Mercury in coal is captured.

This case is quite similar to Case 3, but now almost all of the syngas is shifted to make a hydrogen-rich stream for the combustion turbine (Fig. 8). A slip stream is taken before the shift converter A hydrogen-rich stream leaving the CO_2 scrubber is blended with this slip stream to achieve the required 2.1 to1 hydrogen-carbon monoxide ratio. The combined stream is then fed to the F-T section of the plant.

Combustion turbines need to be specifically modified to handle hydrogen-rich fuel. Flame stability is a problem and can be partially solved by adding methane to the fuel so that it stabilizes the flame.

General Electric, a major gas turbine maker, has worked with this flame stability problem and claims to have it reasonably solved.[7] Obviously this is critical to making the ultragreen case a commercial reality.

Case 5. This illustrates the use of high-sulfur, low-moisture Eastern coal instead of Western coal but has the same flow as Fig. 7. It has two major commercial advantages: It is near major liquid fuel markets, and it enables the use of high-sulfur Eastern coal, as all sulfur is captured.

It has more environmental advantages:

- All CO_2 is captured from the gasification section, but a small amount is emitted from the combustion turbine due to CO burning.
- All sulfur and nitrogen from the coal are captured.
- A small amount of NO_x is emitted from the combustion turbine.
- Mercury in coal is captured.

Case 5, using Illinois 6 coal, is very similar to Case 3, using Montana Rosebud coal. A comparison of the properties (proximate analysis) of the two coals is shown in Table 4.

The two major differences between the coals are in the moisture and sulfur content. Specifically, the Rosebud coal is characterized by low sulfur and high moisture. The higher moisture content of the Rosebud hurts the overall thermal efficiency of gasification, particularly for a GE gasifier, where the coal is slurried in water. Slurry solids concentration for Illinois coal is typically 65% coal or higher, while Montana coal slurry concentrations are in the range of 45% solids.

For cases 5 and 3, the cold gas thermal efficiency for Illinois 6 coal was 79%, while the Montana Rosebud ran 67%. Presumably most of this loss was due to the higher water content in the slurry feed, which must be vaporized before the reaction will take place. This results in more carbon in the coal being converted to CO_2 rather than CO to generate the necessary heat of vaporization.

If CO_2 can be sold, the higher production of it is an economic credit rather than a debit. The revenue from CO_2 sales can actually exceed the revenue from liquid fuels production. The CO_2 revenue stream is one of the key reasons the Montana coal (Case 3) has an ROI of 15% while that of the Illinois coal (Case 5) is 9%.

The CO_2 stream will be smaller in this Case 5 due to the increased cold gasifier efficiency as discussed. The sulfur will be higher due to the Illinois

No. 6 coal's containing about five times as much sulfur.

Case 6. This is the ultragreen mode for converting Illinois 6 coal to electricity and liquid fuels. Its commercial advantages are that it is close to major liquid fuel markets, and it allows high-sulfur Eastern coal to be used, as all sulfur is captured.

There are four major environmental advantages:

- It has extremely low CO_2 emissions.
- All sulfur and nitrogen from the coal are captured.
- A small amount of NO_x is emitted from the combustion turbine.
- Mercury in coal is captured.

The process flow sheet for this case is identical to the ultragreen case using Montana coal in Case 4 (Fig. 8). Recalling that almost all of the CO in the syngas is shifted to hydrogen, this process requires a larger CO shift converter, which results in $37 million more in capital investment for the bigger shift converter.

The amount of CO_2 produced from lower-moisture Illinois 6 coal is smaller due to the higher efficiency of the gasification step. Less water in the gasifier results in higher cold gas efficiency, and less CO_2 produced. CO_2 production for this case is 297 MMscfd compared with 387 MMscfd for the Montana ultragreen case. ROI is 12%, or 3% higher than Case 5 using standard syngas in the combustion turbine.

Even though an additional $37 million is required for the larger shift converter, a higher ROI justifies the additional cost to operate in the ultragreen mode if the CO_2 can be sold for EOR.

Future challenges

If crude oil prices drop back to the $40-50/bbl level, then indirect liquefaction of coal will no longer be economically attractive, particularly with the operating risks associated with this technology and the huge capital investment required.

Providing assurances and incentives for private industry to build and operate one of these coal plants is critical to moving ahead. The technology is essentially proven by the plants operating in South Africa by Sasol but the risk of investing large amounts of money and then having the product values drop is a nagging worry.

The price of crude has fluctuated since its discovery in the 19th Century, and it is reasonable to assume these fluctuations will continue. Thus if a plant is built, its economic outlook will vary with the price of crude.

This has been the experience of the Great Plains coal-to-synthetic natural gas plant in Beulah, ND, which was built in the oil crisis of the 1970s and 1980s.

After the plant was built, the price of natural gas fell. Large quantities of gas became available, and no other coal-to-methane gasification plants have been built in the US.[8]

Action recommended

Given world politics, however, it seems prudent for countries with large coal reserves to move forward with commercialization of this technology. Governments of such countries, including the US, should promote the technology in several ways:

1. Organize a consortium of oil, coal, and power companies to design, build, and operate these plants. Production of electricity and CO_2 for EOR will cushion the economic downside when crude prices drop.
2. Begin or continue loan guarantees for synfuels plants—80% in the US.
3. Provide a price support for the product from the plant, perhaps guaranteeing to purchase the entire liquid product at a set price. This guarantee would not be that significant for the initial plants as they would only produce 5,000-10,000 b/d of liquid fuels.
4. Offer tax credits to corporations that build and operate green and ultragreen coal plants that make either liquid fuels or electricity.
5. Streamline environmental permitting so that construction can proceed in a timely manner.

The potential of coal is a resource base that can reduce such countries' dependence on foreign oil. The US, in particular, has sufficient coal reserves to reduce oil imports, which are becoming a political liability. Converting coal to liquids via gasification followed by F-T (indirect liquefaction) is advisable for the following reasons:

- The technology is commercially demonstrated; there are several commercial plants in operation around the world today.
- The potential for an environmentally green process is exceptional.
- Integration with other technologies such as IGCC and EOR is significant.
- The CO_2 produced is a potentially important revenue stream in any coal gasification plant. Its value depends on nearby oil fields that are suited to EOR by CO_2 injection. Considerable work has been done to determine that many oil fields are suitable for EOR using CO_2 flooding. These same studies need to be carried out on other oil fields.

If the CO_2 can be sold, then shifting the synthesis gas power plant feed to a high concentration of hydrogen is economically attractive despite the increased capital investment for a larger shift converter.

The economics of gasification to coproduce power, transportation liquids, and CO_2 favors Western subbituminous coal over Eastern coal in the US. Western subbituminous coal produces more CO_2/ton of coal gasified while producing less transportation liquid.

Using existing technology, such as IGCC, countries can produce coal as a very clean energy source for both electric power generation and liquid fuels production. Greenhouse gas emissions are almost completely eliminated with CO_2 capture and sequestering.

Coproduction of both electricity and liquid transportation fuels from coal seems to generate the highest ROI. In this study, the potential for coal has been clearly demonstrated. It is time to move ahead in developing transportation fuels from this domestic energy

resource base. It broadens energy resources for liquid hydrocarbons and exploits a huge resource in an environmentally friendly way. ✦

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CERA: Alternative energy sources remain hot industry topic

Sam Fletcher
Senior Writer

Public and government emphasis on renewable and other alternative energy resources was a frequent topic of discussion during the opening session of the annual world energy conference in Houston hosted by Cambridge Energy Research Associates.

Despite popular attention directed at alternative fuels for the future, government policies around the world also need to focus on the development of oil and gas resources that will supply the bulk of all energy needs through 2030, said Rex W. Tillerson, chairman and chief executive officer of ExxonMobil Corp., in a keynote speech Feb. 13 at the CERA meeting.

In another session, John Hofmeister, president of Shell Oil Co., told conference participants, "The public policy opportunity is here and now" to influence US governmental policy on energy over the next 20 years. Hofmeister reminded industry representatives, "In order to make money, you have to do things that don't make money," including funding programs to educate the public about how the energy industry works and the factors that influence energy prices.

It does no good for the industry to be "constantly on the defensive with the public and at war with policymakers," Hofmeister said. As for the issue of global warming, he said, "The public says it's an issue, policymakers say it's an issue. So the industry cannot ignore it."

In a keynote luncheon address, José Sérgio Gabrielli de Azevedo, president and chief executive officer of Brazil's state-owned Petroleo Brasileiro SA (Petrobras), said his country is a leader in the production of crude from deepwater reservoirs and of ethanol from sugar cane. The last oil boom of the 1970s threatened Brazil's economy with high oil prices and stimulated oil exploration by Petrobras, primarily in the deep waters off Brazil and in the US sector of the Gulf of Mexico. Brazil expects to increase its oil production to 3.5 million b/d by 2010 and 4.5 million b/d by 2015 from a current level of 2.4 million b/d.

With the world's largest water supply via its Amazon River basin and half of the world's sugar cane production, Brazil is the largest producer of ethanol. What's more, 20% of the new automobiles produced in Brazil have "flex-fuel" capabilities. Ethanol supplies 40% of Brazil's transportation fuel market, the result of 30 years of investment in that industry. Since cane produces eight times more ethanol than corn, Gabrielli said, there now is no government subsidy to underwrite ethanol production in Brazil as there is in the US.

Petrobras is primarily a buyer of ethanol for blending with the gasoline it produces, but Gabrielli said the company may consider entering biofuels production of ethanol and biodiesel. Technology is developing a "second generation of biofuels" to produce high-quality products, he said.

In a playful slap at the current public and political emphasis on ethanol, Tillerson said there is "not a lot of technology I can add to moonshine."

CERA: Russian official says gas cartel not imminent

Paula Dittrick
Senior Staff Writer

Russia's deputy minister of industry told the Cambridge Energy Research Associates convention in Houston that formation of an international gas cartel is not imminent.

Andrei Reus, speaking through an interpreter, said no one has defined the format or organization for a gas cartel.

Earlier, Russian President Vladimir Putin and Qatari Emir Shaikh Hamad bin Khalifa Al Thani had said they would explore the idea of setting up a gas cartel similar to the Organization of Petroleum Exporting Countries.

"Not a single action we've undertaken, not a single association we become part of, is aimed against anybody," Reus said Feb. 14. "We aren't working against anything specifically. Everything we do is aimed at greater efficiency, greater predictability."

His comments came about a month after Russia resumed delivering crude to Europe via Belarus on Jan. 11, ending a 3-day suspension of supplies along the Friendship pipeline that affected Germany, Poland, Slovakia, and Hungary.

The disruption followed Russia's decision to impose a duty of $180/tonne on oil exports to Belarus, which responded by slapping its own $45/tonne transit tax on Russian oil. The disruption came a year after a Russian dispute with Ukraine that disrupted Europe's gas supply briefly (OGJ Online, Jan. 11, 2007).

US energy policy

US Sec. of Energy Samuel W. Bodman told reporters at CERA that he will discourage any talk about a gas cartel, saying open markets are vital to meeting future world energy demand.

"All countries can act as they see fit, but I think it's fair to say that efforts to manipulate markets by trying to organize the suppliers over the long term will not benefit the suppliers," Bodman told reporters. "I will make my views known." In a speech to CERA, Bodman said moves by governments to restrict foreign investment and increase the reach of state-run energy industries limit access to capital and expertise (see story, p. 35).

He called for stable regulatory frameworks, open investment climates, adherence to laws, and market-based pricing of oil and gas.

"History has shown that an unfettered market is the most effective and efficient way to determine price and allocate resources based on supply and demand," Bodman said.

European policy

CERA Senior Director Simon Blakey said natural gas "appears to be a pawn in a wider strategic and political game" in which Europe seeks a balanced energy security policy.

"Although European countries and Russia have more than 40 years of practice in aligning relationships with industrial reality, the increased scale of natural gas supply needs have rearranged the pieces on the board and introduced new points of leverage into the game," Blakey said, noting that Europe has many voices about gas relations with Russia.

He said Russia's response can seem confusing in part because Russia is responding to "a mélange of mixed signals." Blakey said CERA considers any talk of a gas cartel to be simply a distraction. "It is not an imminent political or market reality," Blakey said. "The short-term markets in international gas trade are not so well developed" for quarterly meetings of natural gas ministers, he said, referring to OPEC meetings of oil ministers.

Meanwhile, European Union leaders closely are following Russia's policy on natural gas because more than 40% of Europe's imported gas comes from Russia.

"There are European countries who have strong traditional bilateral relations with their Russian supplier, where essentially industrial alliances cement political relations and guarantee gas—particularly Germany, Italy, and France," Blakey said, calling those countries "the old Europe."

They contrast with the "new Europe" in which the Baltics and central European countries are confirming their identities and positions within the EU, he said. "In some cases, there is a level of residual discomfort with Russia."

However, Tillerson said oil industry's fuel expertise and technology may have more to contribute during "the second or third levels" of development of biofuels, such as cellulosic ethanol made from nonfood portions of plants.

An earlier joint study by US Departments of Agriculture and Energy concluded the nation has enough biomass resources to satisfy a third of US petroleum needs if cellulosic technologies and resources are employed. A separate study by petroleum industry analysts at Simmons & Co. International Inc., Houston, concluded that cellulosic ethanol has the best growth potential for the biofuel market although US production currently is uneconomic.

Meanwhile, Tillerson said, "Driven by growing prosperity in the developing world, global energy demand is projected to be close to 40% higher in the year 2030 than it was last year, reaching close to 325 million b/d on an oil equivalent basis."

The International Energy Agency in Paris has estimated a total investment of more than $8 trillion in the oil and gas sectors will be necessary over that period. "A large portion of these

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

London buses get cut-rate oil

Venezuela's grandiose President Hugo Chavez plans to support London's transport system with subsidized oil, and he's doing it on the invitation of the city's embattled mayor, Ken Livingstone.

Venezuela last week signed an agreement to subsidize the fuel bill for London's buses by up to $32 million/year, a 20% discount that Livingstone said would fund half-price rates on city transport for Londoners who receive income support.

The scheme will see state-owned Petroleos de Venezuela pay cash to Transport for London, which will reimburse private bus companies for the discounted fares. In return, Livingstone will send his transport chief, Peter Hendy, to establish an office in Caracas, where British officials will share their expertise in traffic management and urban planning.

Foreign aid?

Livingstone confirmed that the cost of advising Venezuela will be less than the value of Chavez's fuel subsidy, causing some observers to note the oddity of the deal—if not its embarrassment.

Richard Barnes, a member of the opposition Conservative party, said it was nonsense for the mayor of London to develop a foreign policy of his own. Said Barnes: "We are a G8 [Group of Eight] capital city, and we are getting foreign aid." One senses that Livingstone has a purpose—an ulterior motive—in such aid.

Roger Lawson, the London spokesman for the Association of British Drivers, recently noted that Livingstone's policies always latch on to the latest popular idea. "Mr. Livingstone's sole agenda," said Lawson, "is to support the policies that will get him reelected, rational or not."

The London mayor is responsible for the most controversial system yet devised for curbing the capital's traffic nightmare: an £8 ($15) charge on cars entering Central London.

The so-called "congestion charge" has proven highly unpopular with the local citizenry—especially residents and other people whose businesses depend on shoppers and deliveries from outside.

Venezuela's poor

A recent Ipsos-MORI poll commissioned by the city says 36% of Londoners are satisfied with his performance, 26% are dissatisfied, and 28% are neither. The rest had no opinion.

Significantly enough, however, in the Ipsos-MORI poll nearly 40% of the people who described themselves as "very dissatisfied" gave one reason for it: Livingstone's congestion charge.

If such dissatisfaction is translated into votes, it means that Livingstone faces a substantial opposition to his policies—some estimate up to 150,000 lost votes.

What better way to shore up his electoral chances than by offering cheap seats to the city's poor, a potential pool of voters said to number some 250,000 souls altogether.

But one wonders how Venezuelans feel about all of that lost revenue since, after all, despite living in the world's fifth largest oil exporter, more than a third of Chavez's fellow citizens exist in poverty. ✦

investments will be required to develop new supplies to simply replace ongoing declines in existing volumes. The rest will be needed for additional supplies to meet the increase in demand," Tillerson said.

"The ability to meet energy demand today and for the future lies in policies that allow companies to search for, develop, and produce available resources wherever they may be, and to encourage further industry innovation to do so in the most efficient and effective manner," he said. Moreover, Tillerson said, "The path to energy security does not lie in attempting to insulate domestic economies from the influences of the global marketplace. Instead it lies in open international trade, competitive markets, diversity of supply, and the strengthening of partnerships between producing and consuming nations. To achieve energy security is to achieve collective security among diverse economies and cultures on a global scale."

Emissions control

Reducing greenhouse emissions from fossil fuels that will furnish the bulk of the world's energy for decades to come "is every bit as important" as the development of alternative fuels, Tillerson said. "Steps taken at ExxonMobil, for example, since 1999 to improve energy efficiency at our facilities, resulted in carbon dioxide emissions savings of 11 million tonnes in 2005. That's equivalent to taking 2 million cars off the road," he said.

He noted that ExxonMobil and other firms collectively contributed $225 million to Stanford University for scientific research into technology breakthroughs to reduce fuel emissions even lower.

"We know our climate is changing, the average temperature of the earth is rising, and greenhouse gas emissions are increasing. We also know that climate remains an extraordinarily complex area of study. While our understanding of the science continues to evolve and improve, there is still much that we do not know and cannot fully recognize in efforts to model and

predict future climate system behavior," Tillerson said.

Therefore, he said, "It is prudent to develop and implement sensible strategies that address these risks while not reducing our ability to progress other global priorities such as economic development, poverty eradication, and public health."

Tillerson said, "Specific policy tools should be assessed for their likely effectiveness, scale, and costs, as well as their implications for economic growth and quality of life. In that regard, rigorous and informed debate—debate that takes into account the essential role played by energy in advancing social and economic progress—will best support thoughtful policymaking."

Just as technology has driven the successful progress of the oil and gas industry, Tillerson said, "I am confident that future technology advances will both expand our understanding of the climate system and enable an effective response." ✦

Energy Sec. Bodman outlines US energy goals

Paula Dittrick
Senior Staff Writer

The challenges of satisfying world energy demand require substantial, sustained investments, US Sec. of Energy Samuel W. Bodman told an annual executive conference in Houston sponsored by Cambridge Energy Research Associates.

"The key to unlocking our energy future is ensuring that the innovation cycle continues at a rapid pace," Bodman said. "We must leverage the tremendous power of private equity, while also making smart public funding decisions, to unleash the world's best scientists and engineers on the problem."

After leaving the conference, Bodman joined Mississippi Gov. Haley Barbour in that state to designate Richton, Miss., as a new site for the US Strategic Petroleum Reserve.

"This new site, in conjunction with an expansion at two of our existing SPR sites, will allow us to increase our emergency stocks to 1 billion bbl," Bodman said. "The further expansion will occur transparently and deliberately over the next 20 years or so."

During a Houston news conference after his CERA speech, Bodman said he has suggested that other parts of the US aside from the Gulf of Mexico be considered as possible SPR sites. Existing SPR sites are in Texas and Louisiana.

A sixth storage project is planned to bring the total capacity to 1.5 billion bbl. That site could be on the West Coast. Bodman said the sixth storage project will be a 20-year program that will be included in the federal budget in 2008.

President George W. Bush's state of the union speech to Congress in January called for increasing the SPR volume to 1.5 billion bbl.

Global goals

Bodman outlined what he called five major global goals:

- Diversify available supply of conventional fuels and expand production.
- Diversify energy portfolios by expanding the use of alternative and renewable sources.
- Promote increased energy efficiency and conservation measures.
- Improve the environment by reducing pollution and emissions.
- Maintain a global energy supply system and protect critical energy infrastructure to ensure a more resilient, secure, and less-volatile market.

"Agreement on these five goals will define a new coalition of countries committed to a peaceful, secure, and environmentally responsible energy future," Bodman said. "And we call upon all countries—producing and consuming nations alike—to join us in embracing them without delay."

Governments must provide policies that encourage investments across the energy supply chain and stimulate new research and development in the private sector, he said.

"Nations that dismiss these principles and objectives do so at the expense of the prosperity and security of their own people and the world's energy security," Bodman said.

Bodman called upon all nations to take steps to protect and modernize critical energy infrastructure, safeguard sea lanes, and facilitate multiple delivery routes.

"The world must be prepared to address any severe supply disruption by maintaining adequate strategic reserves and using them in a coordinated fashion," he said. ✦

UKOOA: UKCS oil, gas output down by 9% in 2006

Uchenna Izundu
International Editor

Production of oil and natural gas from the UK Continental Shelf fell by 9% to 2.95 million boe/d in 2006 compared with 2005 because of technical and commercial difficulties, according to a survey by the UK Offshore Operators' Association.

Production has fallen quicker than originally expected, UKOOA said, signalling that the UKCS is facing serious competition issues with other international basins. Reasons behind the fall in output include poor reservoir

performances, increased maintenance of infrastructure, lower gas demand, and delays in start ups of several projects in 2006-07, UKOOA said. Many of these projects also suffered from bad weather in the UK North Sea.

Production should increase, however to 3-3.1 million boe/d in 2007 because of 30 new project start ups and ongoing investment, according to UKOOA's forecast. There is still a "solid portfolio of activity, provided investments are commercially attractive and resources not a constraint," UKOOA said. About 22 developments are scheduled to start up production in 2008-09.

Major UK North Sea projects that started production at the beginning of this year include Buzzard, led by Nexen Inc., and Dumbarton oil field, operated by Maersk Oil UK.

The central and southern North Sea saw the most exploration and appraisal activities in 2006. The success rate in finding commercial discoveries was 36% with the average size of a discovery being 15 million boe. Last year about 500 million boe was found. "However, 96% of future exploration prospects are expected to be less than 50 million boe and 88% less than 20 million boe in size on a risked basis," UKOOA said. Exploration drilling is expected to dominate 2007 whereas last year the focus was on appraisal activities.

UK North Sea operators are worried about low UK gas prices, which have fallen last year because of low gas demand due to mild weather and large supplies from major gas import pipelines such as the southern leg of the Langeled pipeline.

"We're working on a study looking at how gas prices are affecting investment in the North Sea," Mike Tholen, commercial director at UKOOA told OGJ. "When it comes to oil prices some operators are feeling uncomfortable at the idea of oil prices hitting $40/bbl although 3 years ago people felt that $25/bbl was uncomfortable." Oil prices are hovering at $58/bbl and operating costs for North Sea operators are at $10/bbl.

The UKCS is a mature province that is believed to hold at least 16-25 billion boe of recoverable reserves, but operators are finding that their costs to work there are growing because of inflation, high rig rates, and a scarcity of skilled personnel.

UKOOA is calling for a change in the tax, regulatory, and fiscal regime to attract investors to stay in the UK North Sea and has stressed that the uncertainty over decommissioning rules are discouraging deals. Malcolm Webb, UKOOA chief executive, said it was in discussions with the Treasury and industry to look for solutions.

Webb added that UKOOA would not push for a separate tax regime to govern the southern North Sea which has lower production than other parts and yet very high production costs.

"Without continuing and sustained interest, 45% of pipelines and infrastructure could close by 2020 rendering further recovery of oil and gas uneconomic in areas of the UKCS," UKOOA warned. ✦

COMPANY NEWS

Shell offers $7.4 billion for Shell Canada stake

Royal Dutch Shell PLC offered $7.4 billion to shareholders in its Shell Canada Ltd. subsidiary for the 22% minority stake it does not already own. The offer is a 12.5% increase on the bid it made last year (OGJ Online, Oct. 23, 2006).

In other recent company news:

• BP PLC will exit the UK refinery business by selling its 172,000 b/d Coryton refinery to Petroplus Holdings AG for $1.4 billion so that it can concentrate on developing its other European refineries instead.

• Tesoro Corp. agreed to buy the 100,000 b/cd Wilmington refinery south of Los Angeles and its products terminal from Shell Oil Products US for $1.63 billion, plus the value of oil inventory at closing. The transaction also includes 250 retail sites in and around Los Angeles and San Diego.

• Apache Corp. agreed to pay $1 billion for Anadarko Petroleum Corp.'s interests in 28 Permian basin oil fields in West Texas.

• Dallas independent Exco Resources Inc. will acquire producing oil and natural gas properties, acreage, and other assets in several fields in the US Midcontinent, South Texas, and Gulf Coast areas of Oklahoma and Texas from Anadarko for $860 million.

• Encore Acquisition Co. agreed to buy Anadarko's interests in the Williston basin in Montana and North Dakota for $410 million. Encore also agreed to pay $400 million for Anadarko's interests in the Elk basin and Gooseberry area, primarily in Park County, Wyo.

Shell-Shell Canada

Shell Canada is attractive to its parent company because it has a substantial position in Canada's oil sands and is embarking on a major production expansion and upgrading capacity. Shell Canada hopes to increase bitumen production to 770,000 b/d while increasing upgrading capacity to 700,000 b/d. Shell Canada's first 100,000 b/d expansion of Athabasca Oil Sands is expected in 2010.

Shell Canada shareholders will receive documents setting out Shell's offer of $45 (Can.)/share, but investors have previously stressed that $50 (Can.)/

share was reasonable. Shell also has filed a formal offer with Canadian securities regulators.

Shell Canada's board described the revised bid as "fair" and recommended that shareholders accept it. The deadline for Shell's offer expires Mar. 16 unless it is withdrawn or extended.

Petroplus refinery deal

Petroplus's deal price also includes hydrocarbons valued at closing, BP's adjacent bulk terminal, and its UK bitumen business, which is closely integrated with the refinery in Essex. After the deal closes Petroplus will have 289,000 b/d of refining capacity in the UK, as it already owns the 117,000 b/d refinery at Teeside.

Petroplus will grow its processing capacity by 55% once it starts operating Coryton and transform it into a trans-European refiner with refineries in Switzerland, Belgium, and Germany after closing a deal with ExxonMobil Corp. later this year.

Petroplus also will provide BP's UK-based retail and other businesses with fuel products under a long-term supply agreement. BP will continue to operate its own UK logistics and supply infrastructure, however.

Coryton can process as much as 70,000 b/d of other feedstocks and is a sophisticated refinery with a Nelson complexity rating of 12.0 that produces gasoline, diesel fuel, heating oil, and jet fuel. Heathrow and Gatwick airports take their jet fuel from there and Coryton has one of the largest road distribution terminals in Europe.

Tesoro buys refinery

Tesoro plans to spend at least $1.1 billion in 5 years on improvements and maintenance at the sour heavy crude refinery.

The refinery began operations in 1923 as California Petroleum Corp. Shell acquired a stake through a joint venture in 1998 and became sole owner in 2002.

Tesoro said it plans to offer employment to most, if not all, of about 500 affected Shell employees at the refinery and terminal and certain employees within Shell's retail organization.

Some supply contracts that Shell has with its wholesalers and open dealers in the area will be assigned to Tesoro.

Apache-Anadarko deal

Apache's agreement with Anadarko allows the companies to create a joint venture to effect the transaction.

The Permian basin fields are expected to produce 9,000 b/d of oil and 19 MMcfd of gas this year from 3,950 wells on 143,000 net acres.

Anadarko operates nearly 90% of the properties. Oil makes up more than 70% of the production, produced primarily through waterflood recovery operations.

This deal is the latest in a slew of Anadarko asset divestments following the company's separate purchases of Kerr-McGee Corp. and Western Gas Resources Inc. last year. Anadarko as of yearend 2005 had 2.4 billion boe of proved reserves.

Exco-Anadarko deal

Exco's acquisition includes assets in the Golden Trend, Watonga-Chickasha, Mocane-Laverne, and Reydon areas in Oklahoma, and the Felicia, Speaks, and Cage Ranch areas of South Texas.

This acquisition includes producing properties with net production at yearend 2006 of 103 MMcfd of gas equivalent from 1,327 producing wells. Production consists of 50 MMcfd of gas equivalent from 1,062 wells in the Midcontinent, and 53 MMcfd of gas equivalent from 265 wells in South Texas.

Average acquired working interests and net revenue interests are 75% and 59% in the Midcontinent, and 63% and 49% in South Texas, respectively.

Proved reserves of the assets total more than 400 bcf of gas equivalent and are 72% proved developed and 87% gas. Exco has identified about 200 proved undeveloped drilling opportunities in the package, with 88% of the opportunities in the Midcontinent.

The Midcontinent assets contain 76% of the total proved reserves in the transaction. The reserves are in multiple formations, including the Big 4, Bromide, Springer, Morrow, Chester, Tonkawa, Redfork, and Granite Wash in the Midcontinent, and the Frio, Vicksburg, Miocene, Yegua, and Wilcox in South Texas.

About 91% of the estimated value of the Midcontinent reserves are operated, while 85% of the estimated value of the reserves in South Texas are operated. Net acreage included in the acquisition totals 290,000 acres, more than 71% of which is in the Midcontinent.

The Oklahoma assets being acquired bring Exco's overall Midcontinent production to more than 75 MMcfd of gas equivalent, the company said. The transaction is expected to close in April.

Encore-Anadarko deals

Encore estimates the Williston basin assets have total proved reserves of 21 million boe, which are 90% oil and 81% proved developed producing. The properties currently produce 5,000 net boe/d. Encore will operate 85% of the acquired properties.

The Williston basin assets produce from more than 50 different fields across eastern Montana and western North Dakota. The 70,000 net acres involves primarily waterfloods and producing properties in the Bakken play.

Encore plans to enhance production from the acquisition through drilling, redevelopment, stimulation, and waterflood optimization.

Anadarko operates 93% of the properties, and oil accounted for 90% of the 2006 production.

Encore's other sale agreement, signed last month, includes the 12 MMcfd Elk basin gas plant and Clear Fork Pipeline Co., an oil and gas gathering system.

As of Jan. 1, production was 4,350 b/d of oil equivalent (net) from 614 wells in two fields in the Elk basin and Gooseberry area. Anadarko holds 17,550 net acres and operates all of these properties. Oil accounted for 80% of 2006 production. ✦

Senegal exploration expands Petrobras Africa operations

Peter Howard Wertheim
OGJ Correspondent

An exploration and production contract inked Feb. 5 by Petroleo Brasileiro SA (Petrobras) with Senegal for the exploration of two blocks means that the Brazilian state-owned firm now operates in five African countries: Angola, Libya, Tanzania, Equatorial Guinea, and Nigeria.

Petrobras in early 2006 signed agreements in Angola to explore blocks 15 and 18 in the Congo basin, Block 6 in the Kwanza basin, and Block 26 in the Benguela basin. Petrobras operates all of the blocks except Block 6.

The Brazilian company also holds interests in oil-producing Block 2 and exploration Block 34.

As operator of deepwater Block 18, it has a 30% interest in the unexplored part of a high-potential area. The other sector of that block contains the BP PLC-operated Plutonio project, a collection of several discoveries with 750 million bbl of reserves.

The Petrobras group's signing bonus was $1.1 billion. Participants are Sinopec 40%, Sonangol 20%, and Falcon Oil and the Gema Group 5% each.

Petrobras's strategy contrasts with that of the state oil companies of Venezuela and Mexico, which are involved in E&P activities only in their home countries.

Libya focus

Petrobras has operated in Libya since January 2005, when the company was among winners in the first round of bids held by Libyan National Oil Corp. (NOC).

As a result it acquired the oil and gas exploration rights and a share in production of Area 18, consisting of four blocks that cover 10,307 sq km. The area is in 200-700 m of water in the Mediterranean off northwestern Libya.

Petrobras is operator with 70% interest. The production sharing agreement provides for 5 years for the exploration stage and 25 years of production rights shared with NOC.

Petrobras commissioned Wavefield Inseis to shoot a 3D seismic survey starting in the first quarter of 2007.

The 850 sq km survey in the Pelagian basin will be done by M/V Geowave Commander, which has a 10-streamer capacity.

Tanzania block

The Brazilian company has been in Tanzania since June 2004, when it signed an agreement with state Tanzania Petroleum Development Corp.

The agreement covers Block 5, a 9,250 sq km area in 300-3,000 m of water in the Mafia basin.

Petrobras took part in and won the first round of bids opened by the Tanzanian government, in 2001, and now has 100% interest in the concession.

The contract term was for 4 years of activity, including seismic surveys, geological studies, and basin assessment, and may extend for two periods of exploration that total 7 years.

Petrobras won 100% interest in Block 6 in the third bidding round in May 2005. The production sharing contract for this block is being negotiated.

Equatorial Guinea

Petrobras acquired a 50% interest in the Block L production apportionment contract off Equatorial Guinea in January 2006.

The block covers 4,250 sq km in 500-2,200 m of water in the deepwater Rio Muni basin.

Petrobras purchased the interest from the venture's other participants, whose new shares are now divided as follows: Chevron Equatorial Guinea Ltd. 22.5%; Hess Equatorial Guinea Resources Inc. 12.5%; Energy Africa Equatorial Guinea Ltd. 10%; and Sasol Petroleum International (Pty.) Ltd. 5%.

Chevron will continue as operator, but Petrobras has the option of becoming operator if a commercial discovery is made. Block L is near Hess-operated Block G, where eight oil fields

have been discovered, including Ceiba already on production.

Niger Delta

Petrobras began deepwater operations off Nigeria in 1988.

The holdings should begin making a valuable contribution to the company's international production when giant Agbami oil field and Akpo gas-condensate field start producing in 2008. The company's share in these operations will be around 105,000 b/d to Petrobras's production, making the Nigerian unit one of its largest producing centers outside Brazil in the short and medium term.

Agbami is on OPL 216 operated by Chevron, and Akpo is on OPL 246 operated by Total.

Petrobras also has interests in OPL 250 and 324. The former is in partnership with operator Chevron, Shell, and ConocoPhillips, and the latter is in partnership with Statoil and ExxonMobil.

OPL 324 is the first Petrobras-operated block in deep water off West Africa, and drilling began in October 2004 in a regional record 2,525 m of water.

Ultimate recovery from Agbami could reach 1 billion bbl of light, excellent quality oil. The field extends as far as neighboring OPL 217 and has been joined to OPL 216 to form a partnership including Petrobras, Chevron, and Statoil, with Nigerian concessionaires NNPC and Famfa Oil Corp. Development is under way, and production is expected in 2008.

Total is in charge of Akpo operations. Petrobras is responsible for 40% of the investments, and South Atlantic Petroleum Ltd., Lagos, is concessionaire. The field is in an advanced development stage and should start producing in 2008.

Two other oil fields, Egina and Preowei discovered in 2003, are being assessed. ✦

Nicaragua gets possibly commercial gas find

Norwood Resources Ltd., Vancouver, BC, discovered gas-condensate and light oil in eight zones in what could be Nicaragua's first potentially commercial discovery.

The San Bartolo Rodriguez Cano-1 wildcat in the Sandino basin near the Pacific Coast southwest of Managua discovered hydrocarbons below 6,000 ft in various turbidite sands of the Paleocene Brito formation, the company said. Measured total depth is 8,790 ft with 11.5° deviation at TD.

"The company has logged the well and independent petrophysical analysis combined with core (percussion and rotary) analysis has assigned a combined 532 ft of pay, including 232 ft of conventional pay and another 300 ft of naturally fractured low permeability sands in eight separate zones," Norwood said. "Results from core analysis indicate porosities in the 17% to 21% range with permeability from 3 to 30 md. These porosity measurements agree favorably with the log measurements."

Norwood cemented 7-in. casing at 8,764 ft and plans to stimulate and test San Bartolo-1 in the next several weeks. Drilling took 47 days at this, the country's first exploration well in more than 35 years. The rig is moving 11 km to drill the Las Mesas structure, where amplitude and velocity seismic sections indicate similar but shallower Brito sands. Both wells are on the 845,780-acre Oklanicsa Concession.

The discovery well is 75 miles north of the border with Costa Rica and 75 miles south of the border with Honduras, which just disclosed plans to promote its oil and gas potential (OGJ Online, Feb. 8, 2007). The discovery is 300 miles south-southeast of nearest oil production in Guatemala and more than twice that distance from production in Colombia.

Norwood operates the concession with 70% interest, and Industria Oklahoma-Nicaragua SA has the rest. ✦

Nebraska Forest City prospect awaits bit

A small independent is pursuing the drilling of an oil prospect that could hold several million barrels of oil in the Forest City basin in southeasternmost Nebraska.

The basin, which extends into Kansas, Missouri, and Iowa, has produced several hundred million barrels of oil, but its recent history reveals little drilling.

The principals of Humboldt Oil, former neighbors who now live in Boston and Denver, propose to drill the prospect in 13 and 14-2n-13e, near the Richardson County town of Humboldt. It is 20 miles northwest of Falls City field, largest oil producing area on the Nebraska side of the basin.

The prospect and Snethen field, Dawson field, Honey Creek field, and Livengood field in Kansas line up at about a 30° angle to the easternmost fault in the Humboldt Fault Zone.

The Humboldt fault, which extends roughly from Omaha to Oklahoma City, is the basin's western boundary. It is a vertical fault with the basin to the east.

A 1970s seismic survey by the Nebraska Geological Survey revealed that in southeastern Nebraska it is not just one fault but rather a fault zone. The easternmost fault seemed to have slight right-lateral movement, while the main fault to the west had slight left-lateral movement. A map of the basin's oil fields reveals the slight left-lateral movement.

Richardson County

The easternmost fault is most interesting near the town of Humboldt, said Kent Van Zant, president of Humboldt Oil. Four or five oil fields lie in line from Humboldt to Sabetha, Kan., at a 30° angle with the easternmost fault. The fields have produced a combined 3 million bbl of oil.

The Nebraska survey produced a map of the top of the Devonian Hunton

formation in 1984 on which the Pine Cooper-1 well, in 10-2n-13e near the fault, was incorrectly mapped. The data show a large structure aligned with the oil fields along the 30° angle with the easternmost fault. Humboldt Oil has named this structure the Humboldt Prospect.

Richardson County has produced more than 12 million bbl of oil from the Ordovician Viola and Hunton formations.

The Humboldt Prospect is 2 miles from the fault, just as is McClain field 30 miles away in Nemaha County, Kan. Estimated ultimate recovery at McClain, discovered in 1982 by Pendleton Land & Exploration Co., is 3 to 5 million bbl of oil. The Humboldt Prospect appears to be a McClain analog, Van Zant said.

The Viola formation is the expected reservoir, sealed by the Ordovician Maquoketa shale. All of the formations are less than 4,000 ft deep. ✦

Jamaica

Petroleum Corp. of Jamaica offered four land and 12 offshore blocks for license by a May 1, 2007, deadline.

Eight blocks are under license, mostly in the Caribbean Sea off the island's southwest coast.

A joint venture of Finder Exploration Pty. Ltd., Perth, and Gippsland Offshore Petroleum Ltd., Melbourne, acquired 6,000 line-km of seismic surveys and 23,000 line km of aeromagnetic and gravity data in 2006 on blocks 6, 7, 10, 11, and 12 in the Walton basin (OGJ Online, Apr. 4, 2006).

Rainville Ltd., Calgary, holds blocks 9, 13, and 14 and plans to shoot 2D seismic survey in mid-2007.

Mali

The government granted Selier Energy Ltd., a subsidiary of North Atlantic Resources Ltd., Toronto, oil and gas exploration Block 18 covering 4.8 million acres in the Macina graben 400 km northeast of Bamako.

The northeast-trending graben is 250 km long and 100 km wide in the southern Taoudeni basin and has an interpreted sedimentary sequence 12-14 km thick but no seismic surveys or drilling. Work program is $11.2 million in 4 years.

The Macina graben occupies the preexisting, southwest-trending Gourma aulacogen of the 800 million year old Pan African Pharusian fold belt. In the Gao region, in the eastern part of the Gourma aulacogen, 700 km east of the Macina project, Cretaceous source rocks but no shows were encountered in the off-structure Ansongo-1 well, TD 1,645 m in 1979.

Previous work in the Macina graben consists of a regional gravity survey in 1957 and airborne magnetic surveys in 1963 and 1979. That work led to definition of the Macina graben and the cogenetic Gao and Nara grabens.

North Atlantic Resources has eight gold exploration and development projects in Mali.

Alberta

Nexen Inc., Calgary, plans to spend $200 million on coalbed methane in Canada in 2007, off from $237 million spent in 2006.

The company, which is developing the first commercial CBM project in Cretaceous Mannville coals, has recognized 230 bcf of proved and probable reserves. However, Nexen said its ability to recognize proved reserves is limited until it attains enough production history to assess long-term decline rates.

The 2007 plan involves development of 98 gross sections of land in Corbett, Thunder, and Doris fields near Fort Assiniboine, Alta., using single and multileg horizontal wells.

The company's CBM production target is at least 150 MMcfd by 2011.

Gulf of Mexico

Bois d'Arc Energy Inc., Houston, has a $200 million budget for 2007 that includes expansion into the deepwater Gulf of Mexico by participating in three unspecified projects.

The budget includes drilling 15 wells, including two deep shelf prospects, but the company has deferred drilling the ultradeep Calamity Jane prospect until 2008. Seven of the wells will be drilled deeper than 15,000 ft or in deep water.

The 2006 program resulted in 10 successful wells and three dry holes. The largest discoveries were Sockeye on South Pelto Block 22 and Steelhead at Ship Shoal Block 111. Exploratory wells were successful at Ship Shoal 166, TD 15,709 ft with 72 net ft of pay sands in two commercial reservoirs, and South Timbalier 111 in the quarter ended Dec. 31, 2006.

Comstock Resources Inc., Frisco, Tex., owns 48% of Bois d'Arc Energy.

Corrections

The Exploration Co., San Antonio, is the operator with 50% interest in an early-stage cyclic steam injection project aimed at producing heavy oil in the Maverick basin, Maverick County, Tex.

An item misstated the operator as Pearl Exploration & Production Ltd., Calgary (OGJ Online, Jan. 15, 2007). Pearl is a participant with 50% interest.

An article about Powder River basin coalbed methane should have said that 52 million bbl, not b/d, of produced water has been reinjected into wells permitted by the Wyoming Department of Environmental Quality, and 45 million bbl, not b/d, is treated by an ion exchange process (OGJ, Jan. 22, 2007, p. 34).

Fracture study suggests horizontal drilling will improve Algerian oil field production

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A study of the natural fractures in BA oil field in Algeria's Sahara Desert suggests horizontal and multilateral drilling may improve production.

BA oil field is characterized by considerable production potential. There are four Cambrian reservoir units. We focus on two lithological units (Unit 1, Unit 2) that show very low correlation coefficients between permeability and porosity. This coefficient is only 0.22 for reservoir Unit 1 and 0.19 for Unit 2.

Overall, the reservoir is highly fractured with an index of fluctuation between 1.75 and 0.2. The fractures are vertical and horizontal and classified as open, half-filled, or closed.

This evaluation of the fracture system is based on images from the ultra sonic borehole imager (UBI) and from the circumferential borehole imager logging (CBIL).

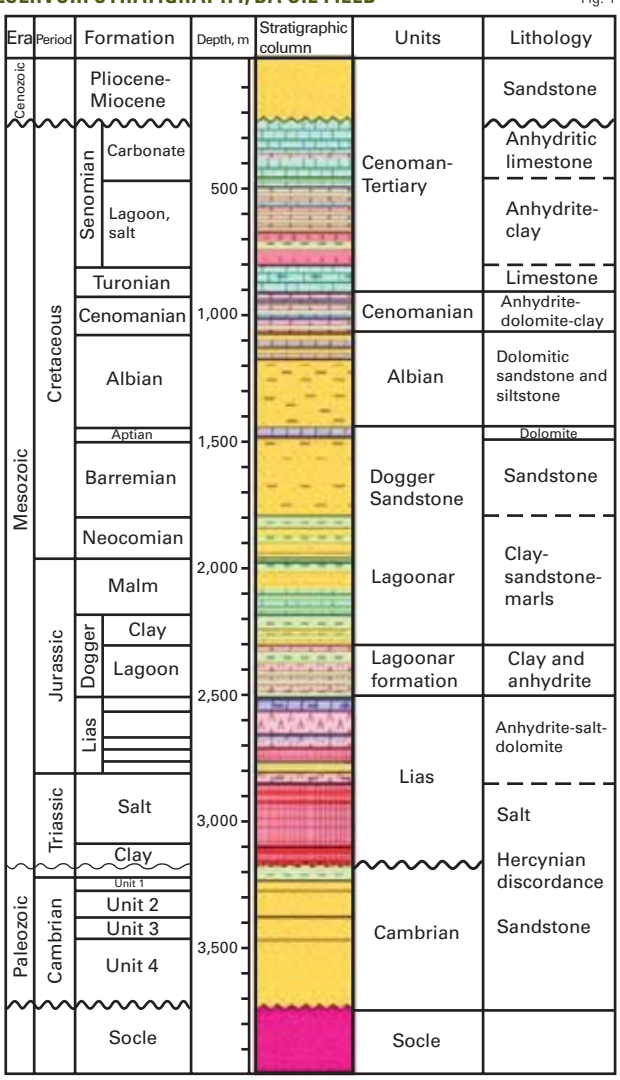
Despite the high intensity and type of existing fractures and large number of vertical wells drilled, oil production from the reservoir is relatively low.

Our results suggest that horizontal and multilateral drilling would improve production in the field. In certain conditions, horizontal wells can offer significant production improvement over vertical wells. In order to efficiently target areas of highest fracture density, we also believe that geosteering should be considered as an affordable and economic option.

Moreover, based on our evaluation of the in situ stress distribution, this article includes our suggestions for the most

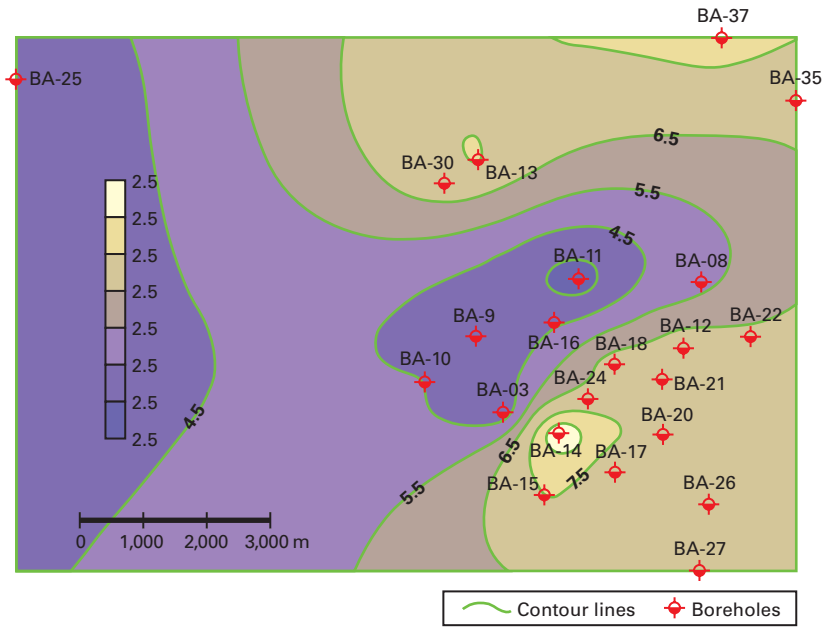
RESERVOIR STRATIGRAPHY, BA OIL FIELD

Fig. 1



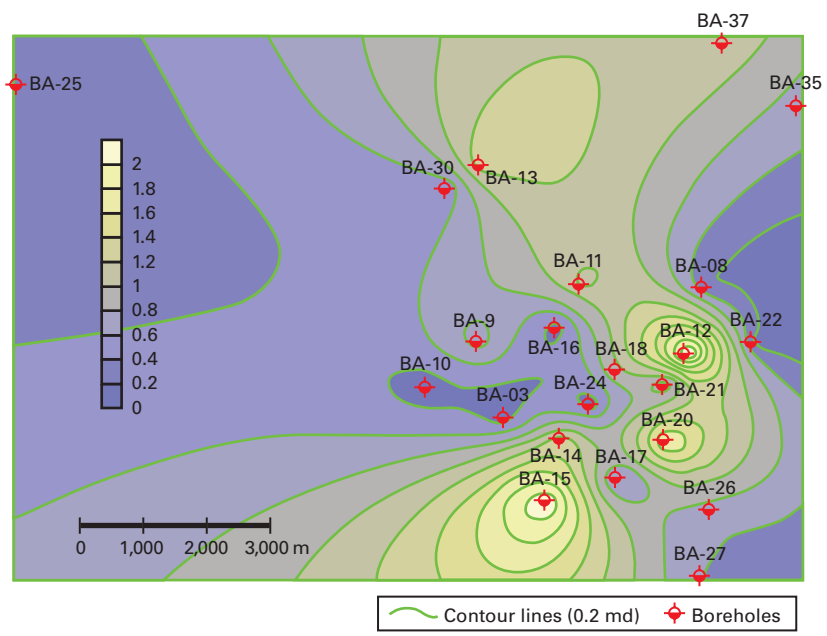
POROSITY DISTRIBUTION, UNIT 1

Fig. 2



PERMEABILITY VARIATION, UNIT 1

Fig. 3



suitable well orientation to ensure well stability.

History

BA oil field was discovered in 1958 and the first borehole was BA-1. As the field was expanded, subsequent wells were consecutively numbered: BA-5, BA-6, etc.

Geologically, the field sits on an important structure in the Algerian Sahara. The reservoir has two main sandstones: Unit 1 and Unit 2.

Resulting mainly from diverse tectonic events, an integrated fracture study was initiated in order to forecast fracture flow potential with regard to the low permeability and porosity characterizing these units. The study was based mainly on openhole logs and borehole imaging. Additional data integrated core observation and regional structural and stress distribution.

First, based on the intensity and distribution of fractures, the field was expected to have higher production. The availability of different borehole petrophysical data, particularly fracture type, distribution, and orientation, provide a good opportunity to design different drilling configurations. Multilateral drilling using stacked and opposed wells seems to be the most efficient technique.

Second, application of multilateral drilling within this oil field will provide even better economical exploitation. In order to target both transversal and longitudinal fractures, the selected technique will constitute an alternative procedure prior to the existing vertical well drilling.

Using geosteering and logging while drilling (LWD), drillers will be able to maximize contact with the objectives, principally the longitudinal fractures.

Moreover, engineers need to determine the most appropriate well orientation in order to ensure well stability. Orientations suggested in this article are based on an in situ stress distribution study, an important input to the proposed well drilling program.

Geology, tectonics

The area has been affected by different tectonic events.[1-3] Chronologically, these events coincided with the Pan-African phase; the Caledonian phase; and the Hercynian phase, which is divided in two movements:

- *Visean phase (Hercynian minor phase).* This phase is compressional, with a direction of N40°E and leading to creation of important structures and NW-SE-trending faults.
- *Upper Carboniferous—Permian phase*

Personal assistant.

Career assistant.

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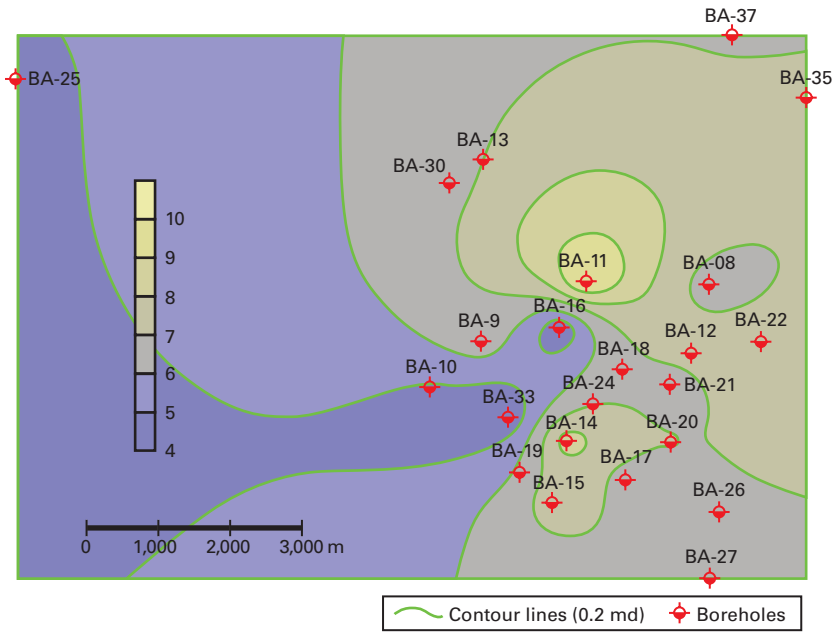
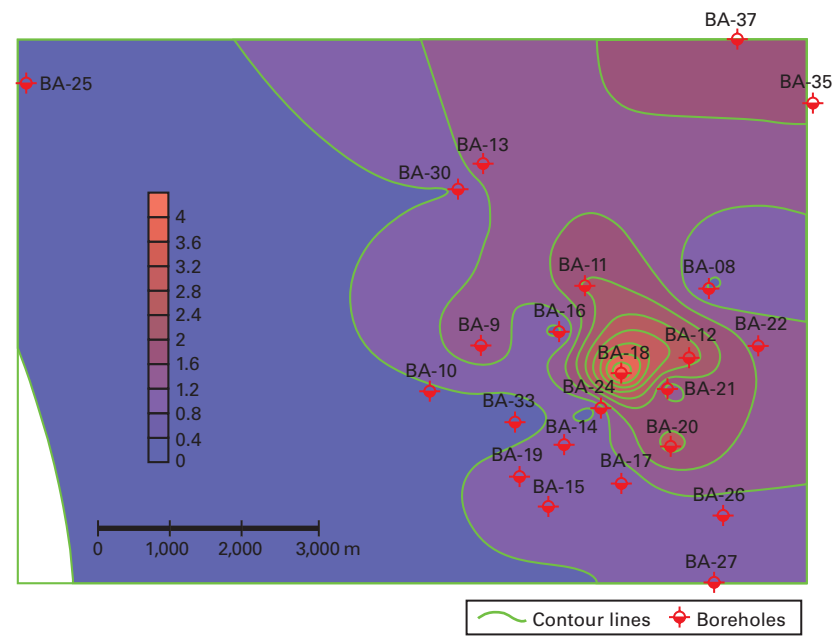
POROSITY DISTRIBUTION, UNIT 2

Fig. 4



PERMEABILITY VARIATION, UNIT 2

Fig. 5



(*Hercynian major*). This phase has also been found compressional, with a direction of N120°E; it is believed to be one of the most important compressional phases affecting the area.[1,2]

The structure has also been affected by later tectonic events including a distensile Triassic-Liasic phase, Autrichian phase, and Tertiary phases.[2,4] As is mentioned by the same listed authors, the impact of other tectonic events is not excluded.

Stratigraphy

The lithologies in this field consist mainly of detrital sedimentary rocks with a Precambrian basement or socle (Fig. 1).[5-7] The Cambrian age reservoir units include:

- *Unit 1; of varying thickness from south to north.* This unit consists of well-sorted, fine to medium grain sands; the rock is very compact.
- *Unit 2; about 100 m thick.* This unit is characterized by the presence of fining upward sequences. It's also distinguished by a decrease of clay cement, compared to Unit 1. The grain size distribution is heterogeneous.

Detailed descriptions of both units as well as other, underlying units have been documented by many authors.[2,6-8]

Petrophysical characteristics

We mapped petrophysical data from the reservoir units. The data distribution shows diverse discrepancies between different boreholes. Notably:

- Unit 1 is characterized by relatively very low porosity, 3.5-8.5 % (Fig. 2).
- Generally, porosity gradient increases towards the southeast and the northeast (Fig. 2).
- The permeability of Unit 1 is low and varies from one borehole to another, with a maximum value of 2 md in BA-12 (Fig. 3).
- Unit 2 is characterized by a maximum porosity of 10%. Unit 2 is also distinguished by a very low porosity distribution (Fig. 4).
- In Unit 2, we noticed that the porosity values improve (relatively) towards the eastern part of the field.
- Permeability values for Unit 2 are low (Fig. 5). The maximum values are seen near BA-1, BA-21, and BA-24.

Fractures

Natural fractures are one of the main targets in this study. Fractures were identified from borehole images, cores, and openhole logs.[8]

Natural fractures are caused by tectonic stresses (tension, compression, torsion) and diagenetic effects, such as those resulting from compaction.

Scientists studying the fracture type, intensity, and orientation have determined that the fractures are the main influence on the reservoir quality.[2 3 9]

In BA oil field, natural fractures can be distinguished into three types: open fractures, half open, and sealed fractures (Figs. 6-9).

Transverse (horizontal) and longitudinal (vertical) fractures typically cross each other (Figs. 6-7). Their occurrence indicates their difference in chronology and different in situ stress distributions. Fig. 10 shows the fracture pattern and intensity.

We have analyzed fractures in different cores from BA oil field. The fractures have different orientations, mainly similar to the major tectonic events affecting the studied area (N120E and N40E). Predominantly, they appear to be related to the directions of early and late Hercynian phase stresses.[1 2 8] Fig. 11 illustrates the stress orientation approximately parallel to the faulting system.

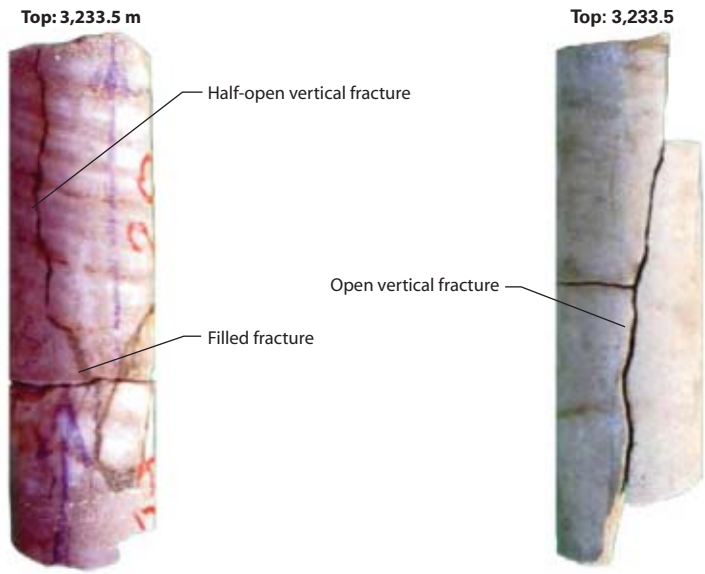
Similar orientation between fractures and faulting system might be one of the better criterion that can be used to demonstrate that fractures found in this oil field are of tectonic origin rather than other sources.

Moreover, core descriptions from both reservoir units show that the lithology consists mainly of sandstones typically characterized by a low percentage of clay, rarely exceeding 15%. Fonta et al. determined statistically that sediments containing less than 30% clay (brittle material) are more exposed to tectonic fractures rather than diagenetic or other events.[10] Similar cases have been studied in many other oil fields worldwide.[11-15]

Analyzing the fracture intensity allows a "quanti-

FRACTURE TYPES*

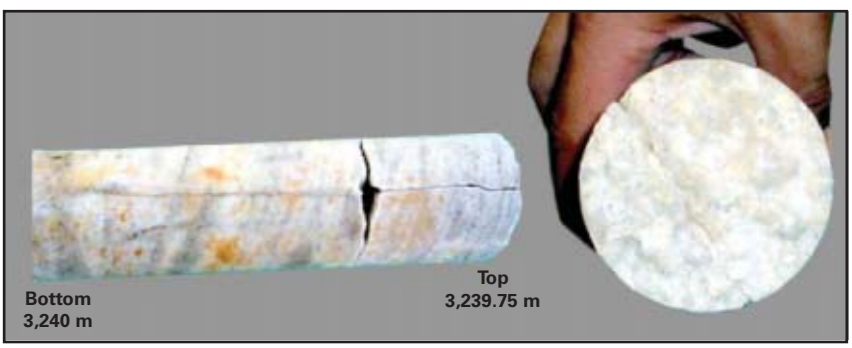
Fig. 6



*Two cores from the BA-17 well.

FILLED, SEALED FRACTURES*

Fig. 7



*Core from the BA-15 well.

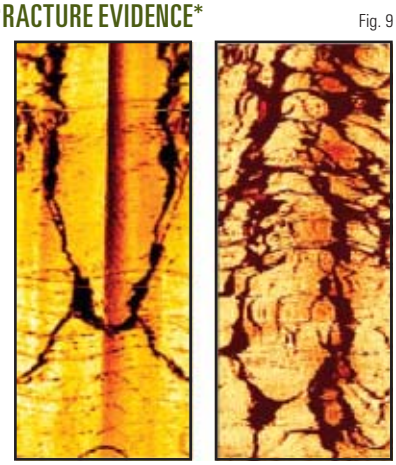
OPEN FRACTURE*

Fig. 8

*Core from the BA-15 well shows a typical longitudinal open fracture.

FRACTURE EVIDENCE*

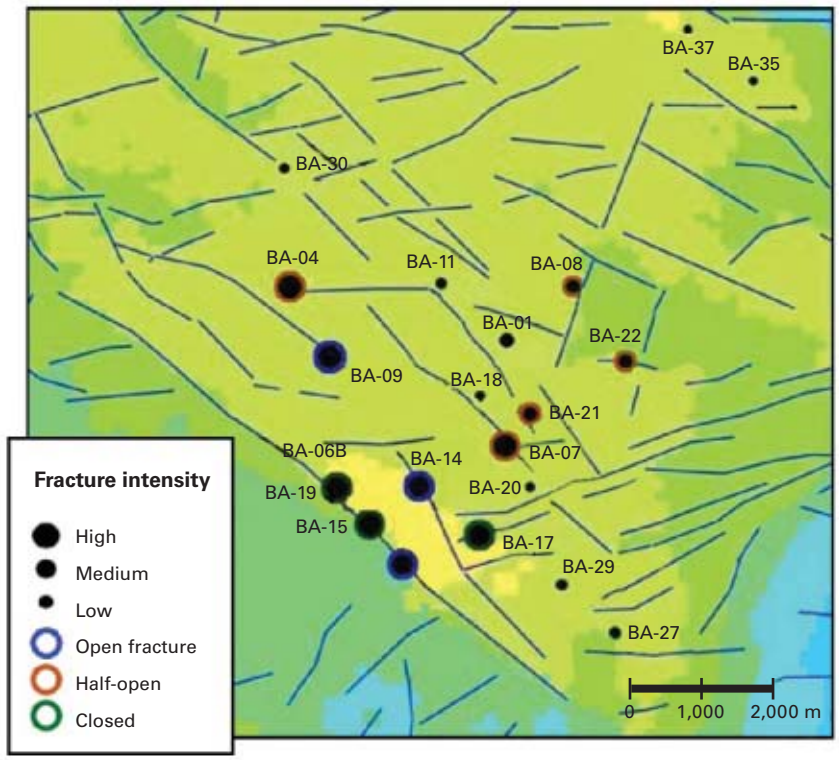
Fig. 9



*Borehole imaging (BHI) shows evidence of fractures in BA oil field.

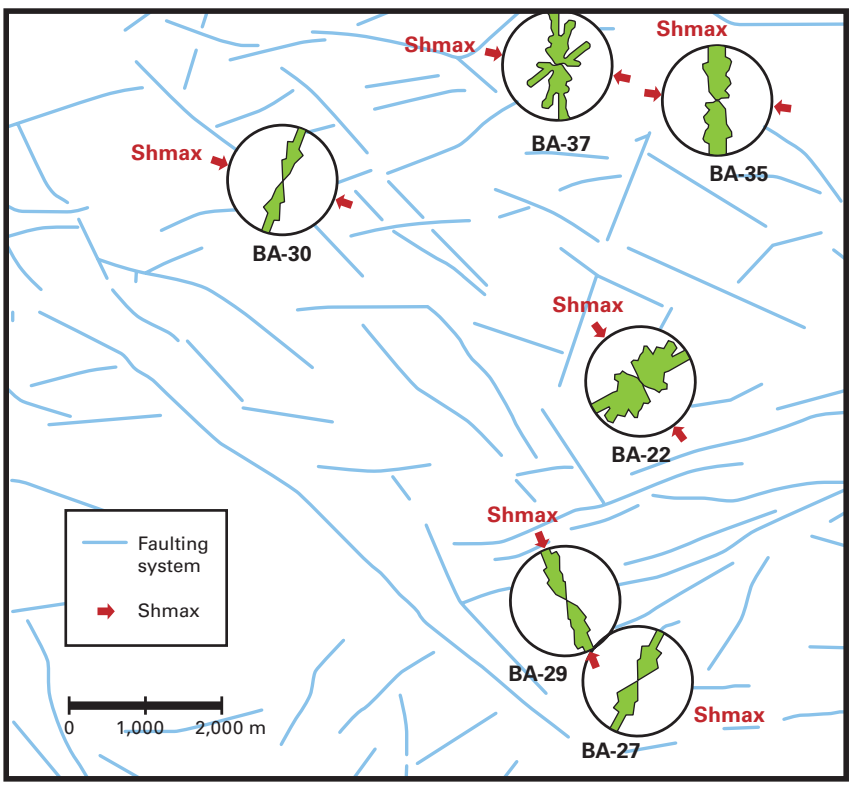
LOCATION, INTENSITY OF DIFFERENT FRACTURE TYPES

Fig. 10



STRESS DISTRIBUTION, FAULTING SYSTEM

Fig. 11



fication" of the fractures according to their fracture intensity index (FII).[16] Results were as follows:

- FII >0.6, corresponds to a highly fractured zone.
- 0.3 <FII <0.6, corresponds to moderate fracture intensity.
- FII <0.3, corresponds to low fracture intensity.

Based on this fracture intensity distribution, it appears that more than 40% of the boreholes encountered within BA oil field are characterized by highly fractured system.[8]

The parameters defined above represent basic guidelines. Applying these guidelines should be done on a zone-by-zone basis.

Stress distribution

Based on the relatively low permeability, we assume that the production from the two reservoir units is unconventional. Further development of the field should focus on the existing fractures, especially on the open and conductive fractures. These would have more influence on the flow circulation and therefore should contribute to improved productivity.

Because of the frequency of natural fractures in BA oil field and their importance, we assume that there are instabilities in the rock. Therefore, the in situ stress distribution should be taken in account prior to decisions on drilling procedures.

We analyzed the data to determine fracture orientations and in situ stresses in order to ensure borehole stability.

There are three principal stress vectors: one vertical, σ_v, and two horizontal, σ_H and σ_h. These stresses are useful to designate the type of drilling and well orientation that should be used, such as horizontal drilling. Analyzing the in situ wellbore stresses is essential to identify the most stable well orientation. Generally, based on stress regime distribution, there are three different types of fractures possible:

- Normal faulting (extensional stress regime) corresponding to $\sigma_v > \sigma_H > \sigma_h$
- Strike slip faulting (transpressional

stress regime) leading to $\sigma_H > \sigma_v > \sigma_h$

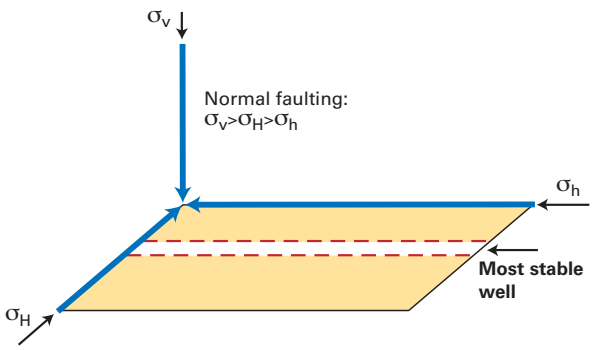
• Reverse faulting (compressional stress regime) corresponding to $\sigma_H > \sigma_h > \sigma_v$.

In the case of normal faulting, the most stable well orientation is perpendicular to the maximum horizontal stress, σ_H. In strike slip faulting, a vertical well is the most unstable well configuration. In the reverse faulting regime, the most stable well is parallel to maximum horizontal stress component, σ_H.[13 15 17-19]

Consequently, we deduce that the most stable well orientation will be perpendicular to the area that has the smallest difference between two main stress components. Fig. 12 illustrates the most stable well orientation in the case of normal faulting. This figure corresponds to one of the main cases present in BA oil field.

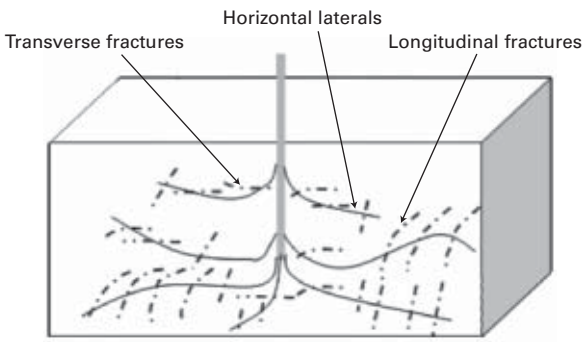
Stress distribution, well stability

Fig. 12



Proposed drilling model*

Fig. 13



*Targeting high fracture density.

Drilling procedure

In modern field management, it is necessary to assess every available recovery technique, including new drilling and well technologies. Using advanced drilling techniques may result in higher production. The use of deviated, horizontal, and multilateral wells, for instance, has become common worldwide.

Current drilling technology is moving towards maximum reservoir contact using extended-reach horizontal and multilateral wells. In some areas, extended-reach drilling can improve the well productivity by lowering the pressure drawdown; this minimizes operating costs and maximizes profitability. A general improvement in drilling and well technology has led to larger parts of the reservoirs being reachable with fewer wells (OGJ, July 10, 2000, p. 36).[20-23]

In addition, improved directional drilling tools including measurement and logging while drilling (MWD and LWD) have led to an increase in the number of long-range and advanced wells.

Horizontal and multilateral drilling allows the wellbore to intersect multiple longitudinal and transverse fractures (Fig. 13). This will probably help optimize reservoir performance. In BA field, where the normal faulting system corresponds to longitudinal fracture orientation, the applied well drilling orientation will be perpendicular to the maximum stress regime (σ_H) intersecting longitudinal fractures.

Moreover, the case study, is concerned with different parameters such as the presence of the high rate of opened and half opened fractures (Figs. 6 and 8) and the considerable sandstone thicknesses of the reservoir, reaching sometimes more than 30 m (Fig. 1). All these factors may be considered the main stimulators to focus on advanced drilling technology.

Based on field experience, the reservoir is sufficiently thick to steer the drilling. Fig. 13 illustrates a proposed drilling model with multilateral wells.

The use of geosteering may reduce the number of wells necessary. The main advantage of this method is that multiple fractures can be intersected with or without a long, horizontal section.

Learnings

Petrophysical properties of BA oil field have unconventional measured values. The presence of fractures is well proven by borehole imaging and core analysis. There are three types of fractures: sealed, half-open, and open. Open and half-open fractures are the predominant type found, both transverse and longitudinal with respect to the cores, and with different orientations.

The presence of fractures influences production, and optimum production should be higher. Vertical drilling does not exploit the fracture distribution as a main path for production enhancement. In order to target a great number of fractures (transverse and longitudinal), the authors recommend horizontal and multilateral drilling.

Reservoir development doesn't necessarily require horizontal and multilateral wells, but it should take into account the in situ stresses. Development team should consider borehole stability in the reservoir. In addition, it is important to emphasize that geosteering would allow the team to steer the borehole into fractures at different orientations.

The importance of fractures in productive capability is known beyond

these Algerian reservoirs; it is seen worldwide and confirmed by many case studies. ✦

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New model predicts solubility in glycols

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A new numerical model predicts the amount of H_2S and CO_2 absorbed per volume of different glycols circulated vs. the partial pressure of acid-gas components and the absorber's temperature. The model covers the full range of dehydration-plant operating conditions and a wide range of experimental data results.

This study shows that the proposed approach is more accurate than routine equations of state approaches in predicting the solubility of acid gases in different glycols. Equation-of-state methods do a generally good job of determining vapor-phase properties, but

Equations

$$A_i = A_{aij} + B_{aij}T_{ri} + C_{aij}T_{ri}^2 + D_{aij}T_{ri}^3 \quad (1)$$

$$B_i = B_{bij} + B_{bij}T_{ri} + C_{bij}T_{ri}^2 + D_{bij}T_{ri}^3 \quad (2)$$

$$C_i = A_{cij} + B_{cij}T_{ri} + C_{cij}T_{ri}^2 + D_{cij}T_{ri}^3 \quad (3)$$

$$D_i = A_{dij} + B_{dij}T_{ri} + C_{dij}T_{ri}^2 + D_{dij}T_{ri}^3 \quad (4)$$

$$x = A_i + B_iP_{ri} + C_iP_{ri}^2 + D_iP_{ri}^3 \quad (5)$$

$$v = \frac{23,645x}{(Mx + S_M(1 - x))} \quad (6)$$

$$vgly = \frac{1 - \frac{Mx}{(Mx + S_M(1 - x))}}{S_g} \quad (7)$$

$$\text{Std. cu m of acid–gas component in cu m of glycol} = \frac{v}{vgly}$$

Nomenclature

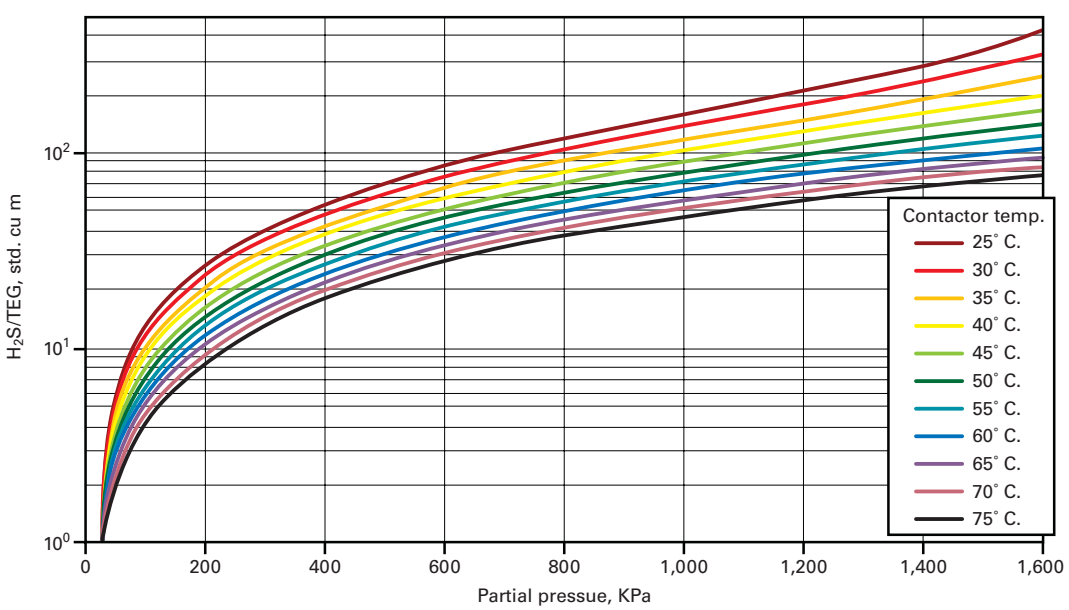
A	=	coefficient
B	=	coefficient
C	=	coefficient
D	=	coefficient
x	=	alkanes in liquid phase mole fraction
Tr	=	reduced temperature
Pr	=	reduced partial pressure

Subscripts
a: An index to show Coefficient for A
b: An index to show Coefficient for B
c: An index to show Coefficient for C
d: An index to show Coefficient for D

i	=	component index
j	=	number of isothermal data sets
V	=	standard volume light alkane component in glycol, cu m
M	=	acid-gas component, molecular weight
Vgly	=	volume of glycol, cu m
NOP	=	number of points
Sg	=	glycol sp gr
SM	=	solvent, molecular weight

Results: H_2S in TEG

Fig. 1



the liquid phase is much more difficult, especially when the liquid contains dissimilar molecules and polar molecules, such as H_2S, CO_2, alcohols, and glycols, that are not handled easily.

This article also compares results of the proposed model with experimental data and Peng-Robinson equation-of-state results. The average absolute deviation for the proposed numerical model falls between 2 and 3%, or 2.5% on average. The equation of state's average absolute deviation results fall between 4 and 24%, or 14% on average.

Glycols and acid gases

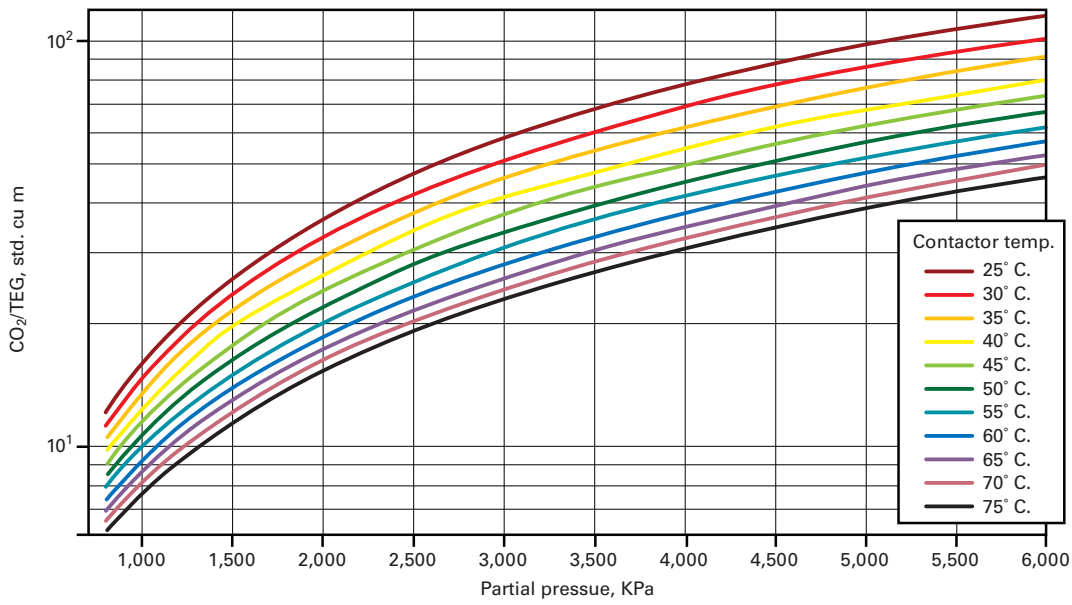
The numerical model offered here is a polynomial, meaning it has 16 parameters.

Glycols have a tendency to absorb acid gases. Acid-gas solubility is a major factor when considering use of a physical solvent in sour-gas dehydration plants. All glycols absorb hydrocarbons and acid gases to some extent. In most cases, hydrocarbon removal is undesirable and should be minimized. In general, the lower temperature and the higher the pressure, the more hydrocarbons and acid gases that will be dissolved in different glycols.[1] In some cases, however, hydrocarbon solubility actually increases with temperature.[2]

Glycol dehydration of natural gas most commonly employs triethylene glycol (TEG). Diethylene glycol and ethylene glycol may also be used in dehydration applications, but they are often not considered due to failure to achieve the dry-gas water content requirements.

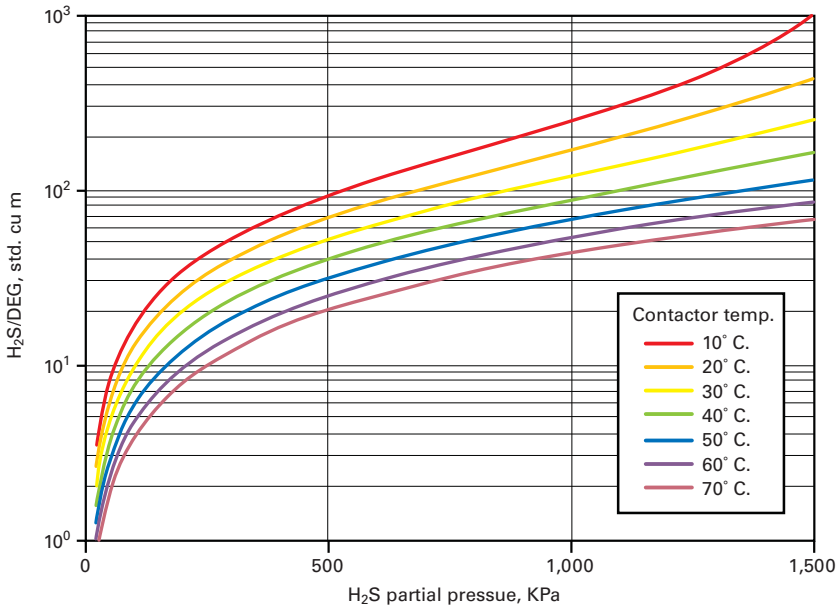
RESULTS: CO_2 IN TEG

Fig. 2



RESULTS: H_2S IN DEG

Fig. 3

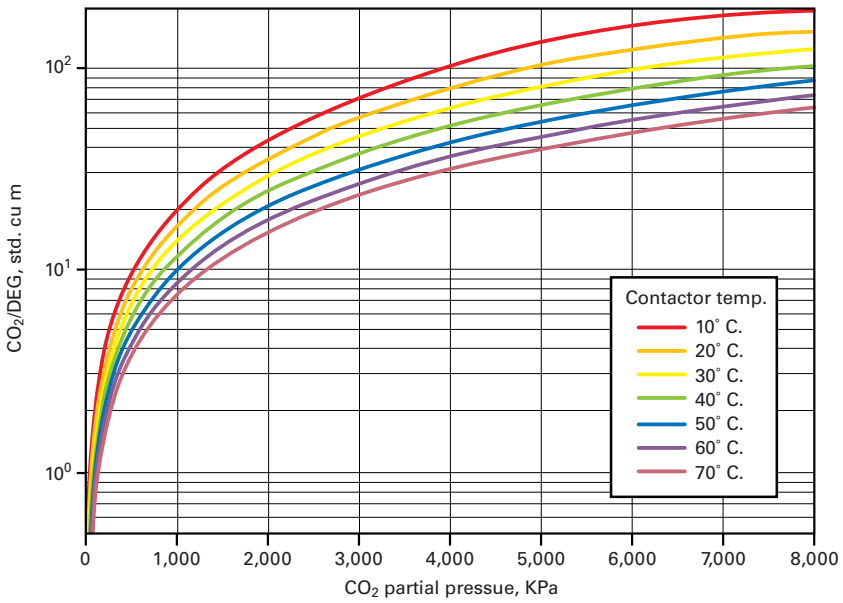


TEG has a higher degradation temperature and can be regenerated to a higher lean concentration with no modifications to the standard regenerator reboiler. EG and DEG, however, can meet water-content specifications when used with enhanced regeneration systems, that is, any system that improves glycol regeneration to achieve a leaner or more concentrated glycol solution.

Enhanced regeneration could be the injection of stripping gas into the reboiler, azeotropic regeneration, or other proprietary processes. The costs associ-

RESULTS: CO_2 IN DEG

Fig. 4



ated with use of EG or DEG increase because of glycol makeup and some form of enhanced regeneration are required to obtain a more concentrated glycol to achieve the dry-gas water content.[3 4]

From an industry prospective, estimation of acid gases and development of control technologies to mitigate the impact of these emissions on the environment have become important issues.[3 4]

Regeneration of the rich glycol solution liberates acid-gas components. How much of these compounds is absorbed and consequently liberated from the glycol depends on their concentrations in the wet gas being dehydrated and on the contactor's pressure and temperature.[5]

In typical dehydration, the glycol is regenerated to about 99% purity or higher. The absorbed amount of acid-gas components depends on the amount of glycol circulated. If the glycol is not regenerated to this purity, then the amount of gas absorbed per unit of lean glycol circulated would be slightly less than the amount calculated by the proposed model.

Glycol will absorb some hydrocarbons at the high pressure of the contactor. Glycol has a special affinity for such cyclic hydrocarbons as benzene, toluene, ethyl benzene, and xylene (BTEX), light hydrocarbon components, as well as polar gases H_2S and CO_2 (acid gases).

Aromatic hydrocarbons and acid gases, however, are very soluble in glycols, and significant amounts of aromatic hydrocarbons and acid gases may be absorbed in glycols at contactor conditions. This may present an environmental or safety hazard when they are discharged from the top of the regenerator.

Regeneration of glycol flashes off all absorbed gases. From here they can be routed to fuel, flare, or gas-recovery system.[3 4]

The new model

NEW MODEL RESULTS, EXPERIMENTAL DATA: H_2S IN DEG

Table 1

Pressure, KPa	Temperature, °C.	H_2S mole fraction (experimental)*	H_2S mole fraction (calculated)	Absolute deviation % (ADP) for model	Peng-Robinson (P-R) EOS results	Absolute deviation % (ADP) for P-R EOS
40.9	25	0.0182	0.0186	2.1505	0.014081	22.6319
95.1	25	0.0414	0.0421	1.6627	0.032759	20.872
219	25	0.0895	0.0924	3.1385	0.07557	15.5642
506	25	0.199	0.1957	1.6863	0.17584	11.6382
1,035	25	0.383	0.3725	2.8188	0.35714	6.752
3.42	50	0.001023	0.0011	7.5269	0.000748	26.8817
22.2	50	0.00573	0.0055	4.014	0.004863	15.1309
142	50	0.0327	0.0333	1.8018	0.031059	5.0183
370	50	0.0825	0.0837	1.4337	0.080697	2.1855
967	50	0.206	0.2062	0.097	0.21012	2
1,810	50	0.369	0.38040	2.9968	0.35714	3.2141
4.91	75	0.000883	9.18E-04	3.8126	0.000735	16.761
192	75	0.0282	0.0272	3.6765	0.028957	2.6844
519	75	0.0735	0.0726	1.3793	0.07772	5.7415
1,180	75	0.163	0.1593	2.3227	0.17441	7
6.07	100	0.00075	8.13E-04	1.9048	0.000645	14
42.8	100	0.0048	0.0047	1.7297	0.004748	1.0833
225	100	0.0234	0.0239	1.4577	0.024986	6.7778
659	100	0.0669	0.0676	4.1896	0.07246	8.3109
1,130	100	0.112	0.114	1.7544	0.1229	9.7321
2,000	100	0.1982	0.2045	3.1786	0.21325	7.5933
7.4	125	0.0007	6.83E-04	2.9412	0.000539	23
73.2	125	0.0058	0.0058	0	0.0062530	7.8103
235	125	0.0179	0.0183	2.1858	0.020225	12.9888
503	125	0.0402	0.0388	3.6082	0.04312	7.2637
984	125	0.0752	0.0749	0.4005	0.08348	10.97
2,210	125	0.163	0.159	2.5157	0.1823	11.8405
Average of absolute deviation, %				**2.5139**		**10.57**

$$\%AADP = \frac{100}{NOP}\sum_{i}^{NOP}\left|\left(\frac{\text{Calculated value}}{\text{Experimental value}}\right)_i - 1\right|$$

*Reference 9.

proposed here applies to pure glycol or to lean glycol (which is essentially pure). This numerical model shows good agreement with experimental data, which were obtained with pure glycols.

Process engineers currently use commercial software to predict the solubility of acid-gas components in TEG and DEG. These software packages use equations of state and need complete process data to simulate wet-gas dehydration plants and consequently calculate the solubility of acid gases in glycols.

It is impossible accurately to predict their solubility in glycols by routine commercial software. Moreover, this commercial software is expensive.[6]

Another widely used procedure employs graphics. These present a convenient visual comparison of the effect of pressure and temperature on the solubility of acid gases in glycols but are less accurate in predicting the solubility of acid gases in glycols, especially when the graphs are plotted in log scale.

Moreover, process engineers have difficulty reading a graph accurately, and modern design techniques are usually based on computer calculations. The benefit of equations is that they can easily be programmed and incorporated into an overall design program, thus bypassing the need for charts or graphs.[5 7]

NEW MODEL RESULTS, EXPERIMENTAL DATA: CO_2 IN DEG

Table 2

Pressure, KPa	Temperature, °C.	CO_2 mole fraction (experimental)*	CO_2 mole fraction (calculated)	Absolute deviation % (ADP) for model	Peng-Robinson (P-R) EOS results	Absolute deviation % (ADP) for P-R EOS
42.1	25	0.00291	0.00310	6.129	0.00256	12.0275
187	25	0.0117	0.01150	1.7391	0.011324	3.2137
377	25	0.0238	0.02240	6.25	0.02272	4.5378
719	25	0.044	0.04230	4.0189	0.04293	2.4318
2,080	25	0.12	0.12100	0.8264	0.1196	0.3333
3,360	25	0.185	0.19150	3.3943	0.1861	0.5946
5,380	25	0.285	0.28650	0.5236	0.2766	2.9474
6,380	25	0.331	0.32210	2.7631	0.3107	6.1329
8,810	25	0.361	0.36300	0.554	0.3525	22.3546
40.5	50	0.00179	0.00180	0.5556	0.001633	8.7709
159	50	0.00647	0.00650	0.4615	0.006391	1.2365
442	50	0.0174	0.01780	2.2472	0.01763	1.3218
997	50	0.0414	0.03940	5.0761	0.039168	5.3913
1,990	50	0.076	0.07710	1.4267	0.076004	0.0053
3,480	50	0.129	0.13050	1.1494	0.12706	1.5039
6,520	50	0.223	0.22420	0.5352	0.2138	4.1256
7,830	50	0.254	0.25670	1.0518	0.2427	4.4488
9,160	50	0.29	0.28400	2.1127	0.2657	8.3793
11,520	50	0.311	0.31620	1.6445	0.29068	6.5338
36.7	75	0.00117	0.00110	6.3636	0.001074	8.2051
161	75	0.00476	0.00470	1.2766	0.00471	1.0504
447	75	0.013	0.01280	1.5625	0.012963	0.2846
1,100	75	0.0312	0.03110	0.3215	0.03138	0.5769
2,640	75	0.0759	0.07230	4.9793	0.07235	4.6772
3,940	75	0.102	0.10520	3.0418	0.104213	2.1696
5,870	75	0.147	0.15030	2.1956	0.146822	0.1211
8,380	75	0.209	0.20200	3.4653	0.193578	7.3789
48.2	100	0.00115	0.00120	4.1667	0.001095	4.6957
127	100	0.00298	0.00290	2.7586	0.002891	2.9866
343	100	0.00769	0.00770	0.1299	0.007782	1.1964
929	100	0.0204	0.02060	0.9709	0.02082	2.0588
2,680	100	0.0592	0.05870	0.8518	0.057738	2.4696
4,520	100	0.0942	0.09660	2.4845	0.093281	0.9756
6,180	100	0.128	0.12720	0.6289	0.1225	4.2969
8,210	100	0.159	0.15770	0.8244	0.15466	2.7296
9,890	100	0.173	0.17540	1.3683	0.17834	3.0867
37.7	125	0.000828	0.00086	3.7209	0.000689	16.7874
94.5	125	0.00191	0.00190	0.5263	0.00176	7.8534
363	125	0.00694	0.00670	3.5821	0.00679	2.1614
842	125	0.0157	0.01550	1.2903	0.015636	0.4076
1,850	125	0.0347	0.03400	2.0588	0.033718	2.83
3,800	125	0.0677	0.06950	2.5899	0.06668	1.5066
5,490	125	0.0978	0.09870	0.9119	0.093154	4.7505
7,130	125	0.125	0.12420	0.6441	0.117025	6.3800
8,340	125	0.143	0.14050	1.7794	0.1335	6.6434
10,490	125	0.162	0.16260	0.3704	0.160159	1.5012
Average of absolute deviation, %				**2.0338**		**4.2624**

$$\%AADP = \frac{100}{NOP}\sum_{i}^{NOP}\left|\left(\frac{\text{Calculated value}}{\text{Experimental value}}\right)_i - 1\right|$$

*Reference 9.

The proposed model has been developed on the basis of experimental data.[8 9]

The solubility of acid-gas components in glycols is a function of temperature and partial pressure. The partial pressure is the product of the operating pressure times the mole fraction of acid-gas components in the gas in the absorber.

The amount of acid-gas components removed by the glycol depends on the following parameters:

- Mole fraction of the acid gases in the feed gas.
- Contactor operating pressure and temperature.
- Glycol circulation rate.[1 5]

Proposed model

The required data for using this approach include partial pressure and mole fraction of individual components in liquid phase. At first the mole fraction of components is correlated vs. partial pressure of components at different constant temperatures; then the calculated coefficients for these polynomials are correlated for different temperatures.

When the calculated coefficients are

NEW MODEL RESULTS, EXPERIMENTAL DATA: H_2S IN TEG

Table 3

Pressure, KPa	Temperature, °C.	H_2S mole fraction (experimental)*	H_2S mole fraction (calculated)	Absolute deviation % (ADP) for model	Peng-Robinson (P-R) EOS results	Absolute deviation % (ADP) for P-R EOS
51.2	25	0.03657	0.0339	7.8761	0.019864	45.7
112	25	0.07131	0.0747	4.5382	0.043297	53.8
432	25	0.2436	0.2513	3.0641	0.164081	32.64
969	25	0.4701	0.4595	2.3069	0.35955	23.5
60.4	50	0.0225	0.0217	3.6866	0.016284	27.62
261	50	0.09328	0.098	4.8163	0.069556	25.43
1,009	50	0.31079	0.3153	1.4304	0.2581	16.95
85.5	75	0.021	0.0193	8.8083	0.01716	18.28
327	75	0.074	0.0756	2.1184	0.064794	12.44
971	75	0.1994	0.2055	2.9684	0.185959	6.7407
2,000	75	0.36	0.34939	3.0367	0.363775	1.048
11	100	0.00206	0.0021	1.9048	0.001728	16.1165
113	100	0.01882	0.0185	1.7297	0.017841	5.209
676	100	0.1014	0.1029	1.4577	0.103916	2.4813
1,920	100	0.2607	0.2721	4.1896	0.27815	6.6935
29.9	125	0.0039	0.0042	7.1429	0.003851	1.2564
132	125	0.01657	0.0159	4.2138	0.017132	3.3917
462	125	0.05338	0.053	0.717	0.05924	10.9779
1,890	125	0.1989	0.1963	1.3245	0.227834	14.547
		Average of absolute deviation, %		**3.0296**		**17.096**

$$\%AADP = \frac{100}{NOP}\sum_{i}^{NOP}\left|\left(\frac{\text{Calculated value}}{\text{Experimental value}}\right)_i - 1\right| = 3.0296\%$$

*Reference 8.

correlated for different temperatures by the least-square method in a gas dehydration plant, the tuned coefficients are calculated and used in Equations 1-4 (see accompanying box on the first page of the article). These polynomials calculate new coefficients for calculating mole fraction of individual components as a function of partial pressure so that finally the polynomial Equation 5 demonstrates the variation of mole fraction as a function of individual components' partial pressures.

The proposed approach consists of the following steps:

1. Select component (i; see accompanying nomenclature list).
2. Select temperature (j).
3. Correlate xi as a function of partial pressure for mole fraction and partial pressure of component (i) at temperature (j).
4. Repeat Steps 2 and 3 for different partial pressures at other temperatures.
5. Correlate corresponding polynomial coefficients that were obtained at different temperatures, Ai = f(T), Bi = f(T), Ci = f(T), Di = f(T).
6. Repeat Steps 1-5 for other components (i).
7. Calculate xi as a function of partial pressure of component (i) from Equation 5.

Then Equations 6 and 7 show the mole fraction conversion of components to volumetric dimensions.

The equation box shows the proposed equations for the solubility of acid gases in glycols in mole fraction. The pressure limits of applicability for CO_2 solubility in TEG are 12,000 kPa partial pressure and temperature of 130° C.

Concerning H_2S solubility in TEG, the pressure limits of applicability are 2,000 kPa and temperature of 100° C., and for CO_2 solubility in DEG partial-pressure range is 10,000 kPa and temperature of 125° C. Concerning H_2S solubility in DEG, the limits of applicability are 2,000 kPa pressure and 125° C. temperature.

Equations 6 and 7 show the mole fraction conversion of acid-gas components to volumetric dimensions.

Results

Fig. 1 shows the model's results of absorbed H_2S in TEG. It also shows the trend of solubility of H_2S in TEG at different temperatures and partial pressures

Fig. 2 illustrates the solubility of CO_2 in TEG as a function of CO_2 partial pressure at different temperatures; it also shows the solubility of CO_2 in TEG is less than for H_2S.

Fig. 3 shows the model's results of absorbed H_2S in DEG. It also shows the trend of solubility of H_2S in DEG at different temperatures and partial pressures

Fig. 4 illustrates the solubility of CO_2 in DEG as a function of CO_2 partial pressure at different temperatures; it also shows the solubility of CO_2 in DEG is less than for H_2S.

Table 1 compares experimental data for H_2S of Reference 9 with results from the proposed model. As can be seen, the average absolute deviation percent at different temperatures and for H_2S in DEG is 2.5139%, but for the Peng-Robinson equation of state the average absolute deviation percent at different temperatures and for H_2S in DEG is 10.57%.

Table 1 also compares the proposed numerical model and Peng-Robinson equation of state results in predicting the solubility of H_2S in DEG.

Table 2 compares the experimental data for CO_2 of Reference 9 with results from the proposed model. As can be seen, the average absolute deviation percent at different temperatures and for CO_2 in DEG is 2.034%, but for the Peng-Robinson equation of state, the average absolute deviation percent at different temperatures and for H_2S in DEG is 4.2624%.

Table 3 compares experimental data for H_2S of Reference 8 with results from the proposed model. As can be seen, the average absolute deviation percent at different temperatures and for H_2S in

TEG is 3.0296%, but for the Peng-Robinson equation of state the average absolute deviation percent at different temperatures and for H_2S in TEG is 17.096%.

Table 4 compares the experimental data for CO_2 of Reference 8 with results from the proposed model. The average absolute deviation percent at different temperatures and for CO_2 in TEG is 1.9394%, but for the Peng-Robinson equation of state the average absolute deviation percent at different temperatures and for H_2S in TEG is 24.19%.

Since dehydrators usually operate at temperatures less than 60° C., there was no practical need to include temperatures higher than 75° C. in graphs of this work. ✦

NEW MODEL RESULTS, EXPERIMENTAL DATA: CO_2 IN TEG

Table 4

Pressure, KPa	Temperature, °C.	CO_2 mole fraction (experimental)*	CO_2 mole fraction (calculated)	Absolute deviation % (ADP) for model	Peng-Robinson (P-R) EOS results	Absolute deviation % (ADP) for P-R EOS
467	25	0.04084	0.04180	2.2967	0.034921	14.4931
750	25	0.064	0.06717	4.7194	0.05527	13.6407
105	50	0.00651	0.00680	4.2647	0.006543	0.5069
709	50	0.04063	0.04040	0.5693	0.043003	5.8405
2,560	50	0.1367	0.13960	2.0774	0.14269	4.3819
5,710	50	0.2611	0.26620	1.9159	0.272518	4.3730
7,840	50	0.3305	0.32670	1.1631	0.331812	0.397
10,720	50	0.3906	0.38290	2.011	0.37358	4.3574
129	75	0.005515	0.00520	6.0577	0.006882	24.7869
710	75	0.03031	0.03030	0.033	0.037038	22.1973
750	75	0.0315	0.03203	1.6825	0.039063	24.0095
2,710	75	0.111	0.10570	5.0142	0.130677	17.7270
6,160	75	0.2121	0.21320	0.5159	0.25799	21.6360
10,630	75	0.3164	0.31490	0.4763	0.364513	15.2064
1,290	100	0.04205	0.04270	1.5222	0.058862	39.9762
3,180	100	0.09725	0.10030	3.0409	0.135989	39.8344
4,930	100	0.1471	0.14750	0.2712	0.19844	34.9
8,260	100	0.2237	0.22290	0.3589	0.29571	32.1904
1,770	125	0.04902	0.04870	0.6528	0.07332	49.57
3,750	125	0.09805	0.09810	0.051	0.14633	49.2402
6,490	125	0.1582	0.15760	0.3807	0.23313	47.3641
9,300	125	0.2104	0.20960	0.3817	0.306859	45.8455
11,840	125	0.2513	0.25050	0.3194	0.361722	43.94
		Average of absolute deviation, %		**1.9394**		**24.19**

$$\%AADP = \frac{100}{NOP}\sum_{i}^{NOP}\left|\left(\frac{\text{Calculated value}}{\text{Experimental value}}\right)_i - 1\right| = 1.9394\%$$

*Reference 8.

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The author

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DECOMMISSIONING—2

Past contamination, future land use set abandonment time line

Katherine E. Roblin
National Energy Board
Calgary

Historical contamination and future land-use plans for an abandoned pipeline location and its facilities can significantly affect the time line of leave-to-abandon proceedings.

Part 1 of this article provided an overview of Canada's National Energy Board's regulatory requirements and responsibilities with respect to pipeline abandonment, typical environmental issues associated with pipeline abandonment, and types and examples of pipeline abandonment addressed by NEB prior to the Yukon Pipeline Ltd. (YPL) case.

Part 2 of the series, presented here, provides a detailed case study of the abandonment and remediation of the YPL pipeline and its pump stations. The article's conclusion will look at abandonment and remediation of the line's tank farm and discuss the practical lessons that can be drawn from the YPL abandonment.

History

In 1942, the US army constructed a 114-mm (4.5-in) OD above-grade pipeline (Canol No. 2) from Whitehorse, Yukon, to Skagway, Alas. This pipeline, a tank farm in Whitehorse (the Upper Tank Farm or UTF), and a pump station at Carcross, Yukon, comprised part of the larger Canol pipeline project, constructed to transport, refine, and distribute liquid hydrocarbons from Norman Wells, NWT, for use in the Yukon and Alaska during World War II. The US army owned and initially operated the facilities.

White Pass and Yukon Corp. Ltd. (White Pass) began operating Canol No. 2 in 1947, reversing the flow to supply Whitehorse and the Yukon with gasoline, diesel, and fuel oil shipped by sea to Skagway from Vancouver, BC. In 1949, the US army resumed operating the pipeline, transporting White Pass fuels as well as their own.

White Pass purchased Canol No. 2 from the US and Canadian governments in transactions from 1958 to 1961 and became the sole shipper via the pipeline. In 1962, the newly formed National Energy Board granted YPL (a wholly owned subsidiary of White Pass) Certificate of Public Convenience and Necessity OC-12 to operate the existing pipeline system consisting of the Canadian portion of the former Canol No. 2, the Carcross Pump Station, and the Whitehorse UTF.

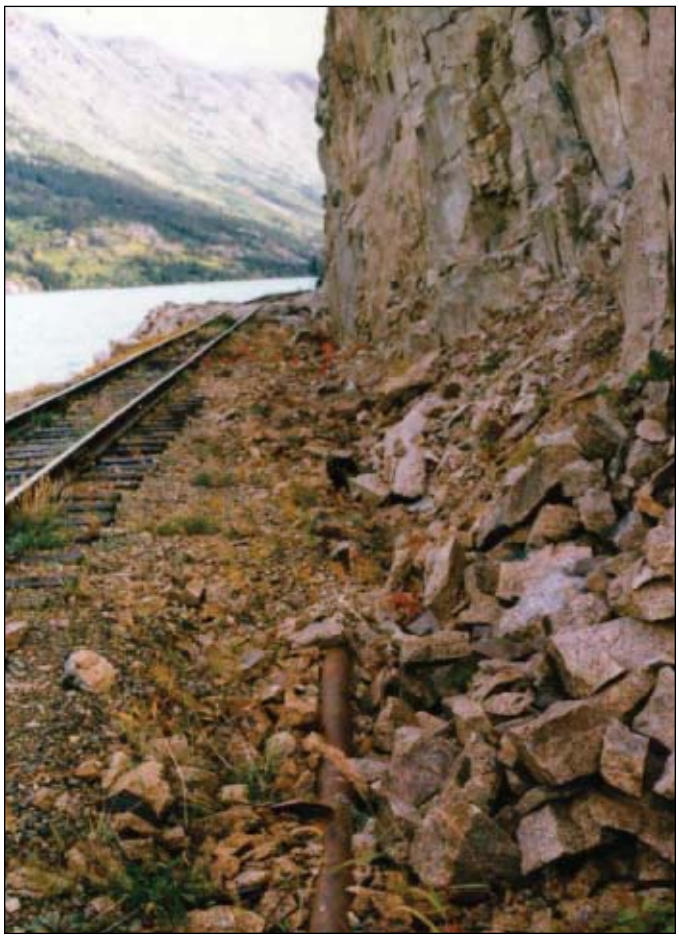
YPL operated the UTF and Canadian portion of the pipeline from 1962 until 1994 with only minor modifications. Other wholly owned subsidiaries of White Pass operated the US section of the pipeline and related facilities in Skagway.

YPL apparently used the Carcross facility as a booster station until 1974, after which all pumping was conducted from Skagway.

Effective Oct. 7, 1994, YPL and related companies discontinued operations on the pipeline between Skagway and Whitehorse, and at the UTF. YPL said that the aging pipeline system was no longer economically feasible to operate and that the cost of upgrading the facilities to meet current regulatory requirements could not be justified. With new or improved highways in the area, trucking fuel to Whitehorse became more economical than transporting it via the YPL pipeline.

A series of inspections and communications during 1994 also saw White Pass served with a Hazardous Facility Order by the US Office of Pipeline Safety in February 1995. The order stated that continued operation of the pipeline from Skagway to the US-Canada border was "hazardous to life, property, or the environment" and that White Pass must complete hydrostatic testing within 120 days or physically abandon the pipeline within 60 days (subsequently extended to June 15, 1995).

In January 1995, YPL notified NEB that the pipeline had been depressurized and that the UTF was being drained. In May 1995, NEB staff inspected the YPL facilities and YPL began pigging the pipeline to remove fuel and clean the pipe interior. Effective June 1, 1995, White Pass sold its petroleum distribution assets.[1,2]



War-time expediency drove the US Army to build the bulk of the YPL pipeline on grade within the right-of-way of the White Pass and Yukon Route railway; including a 26-km passage along the shores of Lake Bennett, part of which is shown here. This positioning exposed the pipeline to a variety of third-party and natural hazards, including rockfall (Fig. 1).

Regulatory process

In July 1995, pursuant to Paragraph 74(1)(d) of the NEB Act, YPL formally submitted its application to abandon its NEB-regulated facilities. NEB subsequently requested comments and advice from the public and regulators, and corresponded with YPL regarding further information requirements. Meanwhile, YPL commenced environmental site assessments (ESAs) of its facilities. In June 1996, YPL requested permission to remove the aboveground storage tanks (ASTs) from the UTF so that they could proceed with further ESA work. In response, NEB issued Hearing Order MH-3-96 to call a public hearing in accordance with Section 24 of the NEB Act.

NEB held the hearing in Whitehorse on Aug. 20, 1996. Registered intervenors for the hearing included the Hillcrest Community Association, the Yukon Conservation Society, Environment Canada, Transport Canada, the City of Whitehorse, the Yukon Territorial Government (YTG), and the BC Ministry of Environment, Lands and Parks (MELP). All actively participated, with the exception of BC MELP, which indicated that it had already had its concerns satisfactorily addressed. Canadian Heritage, Health and Welfare Canada, the US Department of Transport (Office of Pipeline Safety), Indian and Northern Affairs Canada, and a local contractor provided letters of comment.

No one contested the pipeline abandonment. The hearing, therefore, focused on how the pipeline would be dismantled, how historical contamination would be addressed, and whether YPL had sufficient financial resources to properly abandon the pipeline system (NEB was satisfied that it did). Participants also discussed the potential for future residential development at the UTF and the concept of risk-based remediation.

Understanding of subsurface conditions and the extent of soil or groundwater contamination was still very limited at the time of the hearing and no one had yet identified the presence of phase-separated liquid hydrocarbons on the groundwater table at the UTF and Carcross. YPL had performed a Phase I (nonintrusive) ESA and a limited initial Phase II (intrusive) ESA at the UTF. Only a Phase 1 ESA had been performed on the pipeline right-of-way. Access issues prevented performance of an ESA at the Carcross Pump Station.

NEB determined, pursuant to Paragraph 20(1)(a) of the CEA Act, that, taking into account the implementation of YPL's proposed mitigation measures and those set out in the leave-to-abandon order, the proposed pipeline abandonment was not likely to cause significant adverse environmental effects. NEB then issued order MO-7-96 granting YPL leave to abandon the pipeline and enabling YPL to begin dismantling the system and proceed with additional ESAs.

Pursuant to Subsection 19(1) of the NEB Act, however, NEB delayed the date that formal leave-to-abandon status would come into force until YPL fulfilled a number of conditions. Among other things, YPL was to complete and report on the outstanding Phase I and II ESAs, plan and conduct appropriate remedial work, and file a final report demonstrating the success of the remedial work. NEB also required YPL to "provide information to and consider the comments of any persons who indicate to YPL that they wish to be consulted."[1-3]

Environmental setting

The YPL pipeline ran 144.5 km from the US border at White Pass Summit (near Fraser, BC) through Carcross and north to Whitehorse. The US Army, driven by war-time expediency, constructed the majority of the pipeline on

grade within the right-of-way of the White Pass and Yukon Route railway (WP&YR, at the time was also owned by White Pass). Where it deviated from the railway right-of-way closer to Whitehorse, the Canadian government sold the pipeline to YPL with its own 30-m right-of-way, but YPL never received official title to the land.

Including 52.3 km in BC and 92.2 km in the Yukon, the pipeline and railway traversed a variety of generally sparsely populated, sometimes sandy but more frequently marshy or rocky terrain, crossing many creeks and following the shorelines of numerous water bodies, including 26 km along the shore of Bennett Lake south of Carcross (Fig. 1) and 4 km along the shores of Shallow Lake and Bernard Lake near Fraser (Fig. 2).[1]

The pipeline's general position on grade adjacent to the railway, roads, and rock cuts (particularly in the more mountainous terrain toward the southern end of the pipeline) exposed it to potential third-party and natural damage.

Some segments lay below grade. This occurred:

- Within Whitehorse and Carcross.
- Where the pipeline crossed railways, highways, and secondary roads.
- Where the pipeline had become buried (intentionally or unintentionally) by rockfall, railway ballast, or other protective materials, or by overgrown vegetation.

The pipeline had no cathodic protection and was substantially uncoated, and was therefore susceptible to corrosion where it was buried, under water, or in contact with wet ground.[1-3] These factors contributed to numerous product releases along the right-of-way during the pipeline's operating history.

Abandonment, mitigation

YPL pigged the pipeline prior to the abandonment hearing to remove remaining product and clean the interior of the pipe. Compressed air propelled a squeegee-type pig from the highest point on the pipeline toward Skagway, and then from the same point toward Whitehorse. The pig passed through the line up to three times. YPL disconnected the pipeline at the valve locations, installed taps at low points on the pipeline to drain any trapped product, and then visually inspected the interior of the pipe and tested for organic vapors to ensure it was clean.

YPL committed to remove most of the pipeline; it being generally above-grade and easily accessible by rail or road. Removal required cutting the pipe into manageable lengths, lifting it by crane onto a rail car or truck bed, and transporting it offsite for reuse or recycling. Plans called for pipe buried under a thin layer of rail ballast or fill

to be hand-exposed at regular intervals, cut, and lifted straight out of the ground, avoiding contact with vegetation. Restoration included hand-raking the disturbed soil back into place and revegetating the area, as required.

Removing pipe from standing water or wetlands required it be cut, tested, and plugged where it entered and exited the wet area, and then pulled out of the area from one end. A 2-km section in a wetland near Cowley Lake, Yukon, called for removal in winter to minimize disturbance of the wetland.

Pipeline buried under roads or railways needed to be filled with an inert material and abandoned in place.

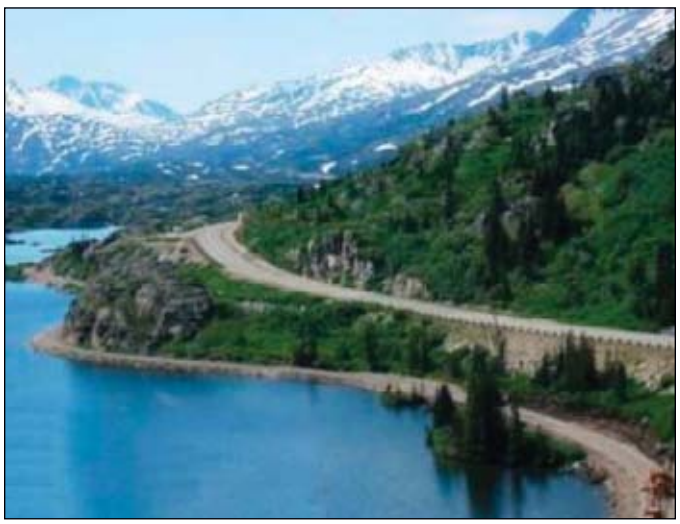
A qualified contractor, in accordance with applicable regulations and guidelines, was to conduct pipeline removal, with removal in environmentally sensitive areas to be monitored by a qualified professional. The timing of work was to minimize effects on wildlife. Unstable slopes were not to be disturbed and silt fences were to be used where appropriate. Crews carried spill cleanup material for quick response in event of a release.[1-3]

During pipeline removal, YPL collected soil samples every 100 m along the pipeline for visual observation and organic vapor monitoring. The company attributed two hydrocarbon-affected areas to rail activity to be addressed by WP&YR.[4]

NEB staff inspected the pipeline right-of-way in June 2005 and observed that the majority of the pipeline had been removed. Cut ends of sections abandoned in place were welded closed. A linear indentation was still visible in some areas where the pipe had rested directly on the ground.

Assessment, remediation

YPL took a qualitative risk-based approach to identify areas of potential environmental concern (APECs) during a Phase I ESA of the pipeline right-of-way. YPL conducted a reconnaissance of the entire right-of-way, looking for visual evidence of contamination and assessing each recorded spill based on the age of the spill, season during which the spill occurred, hydrogeology of the site, and distance to receptors. As a result of this assessment, five APECs were identified on the right-of-way.[5]



Another of the pipeline's railway-associated RoW included a 4-km stretch along Shallow Lake (Fig. 2).

Phase II ESAs of the APECs on the right-of-way included soil vapour surveys and test hole excavations, as well as borehole drilling and monitoring well installation where the potential for groundwater contamination was identified. YPL also collected water samples from private drinking water wells within 300 m of the right-of-way. YPL compared analytical results for soil within or adjacent to road or railway right-of-ways with Yukon Contaminated Sites Regulations (CSR) and CCME criteria for industrial land use. It compared groundwater samples with CSR and CCME drinking water criteria. Groundwater samples from monitoring

wells were also compared with CSR and CCME freshwater aquatic life (FAL) criteria. Two APECs required remediation.[6]

In situ bioremediation addressed one APEC, while excavation and land farming dealt with the other. Confirmatory soil and groundwater samples met Yukon CSR industrial land use, FAL, and drinking water criteria, except for one minor exceedence of the soil criteria, which YPL expects to naturally attenuate.[4 7]

Pump station

The Carcross pump station sits on the north edge of the village of Carcross, about 370 m northeast of Bennett Lake. Located on the edge of the Carcross Desert, the 8.3 hectare site is well drained, with rolling sandy hills vegetated by scattered stands of pine and poplar trees (Fig. 3). The water table is 6 m to 16 m below grade and flows principally toward Bennett Lake to the southwest. Adjacent land to the northwest and southwest is undeveloped, while the northeast edge of the property is bounded by the railway right-of-way. There is residential land use to the south and commercial land use (including a gas station) about 300 m to the south-southeast.

Facilities on the site in 1996 included an empty and disconnected 1,600 cu m cylindrical AST, yard piping, foundations of the dismantled pump station and maintenance shop (including a mechanic's pit), stored pipe and pipeline components, barrels, and other refuse. Previous facilities included two additional 1,600 cu m cylindrical ASTs, four ellipsoidal ASTs, a filter house, barrel filling shelter, and tanker truck loading rack. The railway owns the land.

Tank cleaning involved removal of all solid, liquid, and vapor phase product, venting the tank to atmosphere, and placing grates over access ports to prevent unauthorized entry. Resulting wastes were to be handled in accordance with Yukon Special Waste Regulations.

A qualified contractor was to conduct tank dismantling and removal in accordance with applicable regulations and guidelines, with scrap metal transported offsite for recycling.[1]

In contrast to the right-of-way, YPL conducted relatively standard Phase I and Phase II ESAs at the Carcross station. The company reviewed historical records, interviewed former YPL employees, and conducted a sight reconnaissance. It then performed soil vapor surveys, test hole excavation, drilling, monitoring well installation, and soil and groundwater sampling (including sampling of nearby private drinking water wells). YPL also consulted old drawings and conducted a geophysical survey to identify and locate potential buried yard piping for removal.

YPL's Carcross pump station site, also located near Lake Bennett, faces historical contamination concerns not associated with the pipeline itself (Fig. 3).

Elevated subsurface vapor occurred in the immediate vicinity of both onsite cylindrical ASTs (particularly the one recently removed) and the maintenance shop. Phase-separated liquid hydrocarbons up to an apparent thickness of 1.1 m were present on the groundwater surface in two monitoring wells.

YPL compared analytical results with CSR and CCME criteria for industrial land use (soil), FAL (groundwater samples from monitoring wells), and drinking water (private water well samples), substantially delineating soil and groundwater effects onsite. The company determined that on site liquid and dissolved-phase hydrocarbon plumes were stable and immobile. YPL also stated that excessive off site, downgradient groundwater levels originated from the off site AST. Hydrocarbons did not affect nearby private drinking water wells.[8]

Excavation and land farming addressed remediation of shallow affected soils (<3 m deep). Site-specific numerical standards (SSNSs) for soils deeper than 3 m below grade indicated that soils saturated with hydrocarbons could be left in place so long as phase-separated liquid hydrocarbons were not present.

A liquid hydrocarbon recovery program was initiated to deal with liquid and dissolved hydrocarbons.

YPL removed all identified yard piping from the site for recycling, and recovered liquids from inside the pipes for appropriate disposal. Confirmatory shallow soil samples met Yukon CSR industrial land use criteria, except for one minor instance which YPL expects to naturally attenuate.

Phase-separated liquid hydrocarbon recovery continues steadily (about 0.3 l./day as of May 2005) and dissolved hydrocarbon concentrations adjacent to the liquid plume remain in excess of Yukon CSR FAL criteria.[7 9 10]

Parties following the process requested and were provided with satisfactory details regarding the remediation methodologies.[11] They also pointed out APECs not previously investigated by YPL, resulting in an expansion of the areas investigated and remediated.

The Carcross Pump Station property is currently vacant, zoned industrial, and owned by the railway. YPL asserts that "there are no plans to use or

develop the site for any purpose other than a storage yard for rail materials". As such, the human health receptor YPL used to calculate SSNSs was a teenaged trespasser on site for 1 hr/day, 365 days/year. Based on this scenario, YPL concluded that the site presents no human health risk in its current state.[9] Abandonment of the site in its current status could, however, restrict future industrial development.

The SSNSs also fail to account for hydrocarbons moving from soil into groundwater. YPL has committed to meeting FAL criteria after completion of phase-separated liquid hydrocarbon recovery.[8-9] It is not clear, however, whether the company can achieve FAL groundwater criteria so long as associated soil remains saturated with hydrocarbons.

Regardless, it may be a long time before YPL completes liquid hydrocarbon recovery. Recovery under way since 1998 shows little sign of abating. No-one knows how much product remains in the ground. Although it appears that the liquid and dissolved plumes are relatively stable, the size and behavior of these plumes are not well understood. YPL could consider more aggressive liquid hydrocarbon recovery techniques, but one might debate the justification for such measures given the lack of current plans to redevelop this land and the apparent lack of current risk it poses to human health or the local ecology.

The most powerful impetus to clean up the Carcross site may be the desire to achieve overall remediation of the pipeline system, thereby bringing leave-to-abandon into effect and allowing more marketable YPL assets, such as the UTF, to be redeveloped. ✦

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New line of shock tools

A new line of shock tools is designed to provide an improved rate of penetration and minimize axial vibrations produced by the drillbit.

The tools will absorb shock load on the drillstring and drillbit.

Tools are oil lubricated and sealed, which help supply a longer operational life, the firm points out.

The tools also help reduce vibrations utilizing a series of springs. Tools can be equipped with light, medium, or heavy weight springs to accommodate various drilling conditions.

Designed to enhance the firm's roller reamer line of products, the tools are available in sizes of 4¾ in. to 9½ in.

Source: **Stabil Drill**, Box 81548, Lafayette, LA 70598.

New dry ice blaster cleans equipment in-place

This new dry ice blaster for in-place cleaning eliminates the need to disassemble machinery before it is cleaned.

The new IB 15/80 dry ice blaster uses compressed air to propel tiny dry ice

pellets at supersonic speeds so they flash freeze and then lift grime, paint, rust, mold, and other contaminants from metal surfaces. Moreover, the pellets quickly vaporize into the air so there's no waste water or solvents to dispose of, only the soiled contaminant that can be swept up.

Dry ice is nonabrasive, using micro-thermal shock to lift the contaminant off the surface. The dry ice temperature is −109° F.

Dry ice blasting is environmentally friendly, the company notes. CO_2 pellets are nontoxic and nonhazardous.

The IB 15/80 operates on 120 v electricity (5 amp) and uses a blasting pressure of 44-230 psi.

Compressed air requirements range from 150 to 3,000 cfm. Dry ice pellets are 3 mm—the standard industry size—with consumption at a rated 66-220 lb/hr. The unit weighs 198 lb and is made of stainless steel. It is ETL certified to accepted safety standards, the firm says.

Source: **Karcher Industrial Products Div., C-Tech Industries**, 4275 NW Pacific Rim Blvd., Camas, WA 98607.

Pride International Inc.

Houston, has announced three appointments for its Latin America Land and E&P Services group. K. George Wasaff has been named chief executive officer, James M. Mitchell joins as chief financial officer, and Carlos F. Etcheverry has been promoted to chief operating officer.

Wasaff

Etcheverry

Wasaff previously was employed by El Paso Natural Gas Co., Enron Corp., and most recently by Ashmore Energy International and Prisma Energy.

Mitchell joins Pride from Grant Prideco Inc., where he has been employed since 1999. He previously held positions with Azurix Inc., EVI Inc., and Arthur Andersen LLP.

Mitchell

Etcheverry was employed by Halliburton Co. as country manager-Argentina prior to joining Pride in 2002.

Chastain

In another announcement, Pride International Inc. has named Jeffrey L. Chastain as vice-president, investor relations, for the company. Chastain, who holds bachelor's and MBA degrees from the University of North Texas, has 23 years of experience in investor relations and analytical roles in energy and financial investment industries.

Pride International Inc. is one of the world's largest drilling contractors, providing onshore and offshore drilling and related services in more than 25 countries.

Mustang Engineering

Houston, has announced that Ronald Walker has joined its process plants group as a professional services specialist.

Walker has more than 20 years of experience in business development and project management in the refining and chemical industries. Based in Mustang's La Porte, Tex., office, he will provide staffing support to clients for onsite engineering and support services. He will also provide chemical and polymer project development support for the office.

Mustang Engineering, a subsidiary of John Wood Group PLC, is an independent services provider specializing in design, engineering, procurement, project management, and construction management. The company offers these services through its six business units: upstream oil and gas, midstream, pipeline, automation and control, refining and petrochemicals, and process and industrial.

John Wood Group PLC is an international energy services company operating in 44 countries. Wood Group provides a range of engineering, production support, maintenance management, and industrial gas turbine overhaul and repair services.

Liberty International Underwriters

Houston, has appointed Tommy Laurendine as head of risk engineering for its US exploration and production line of business.

Laurendine has over 25 years of experience as an offshore structural engineer. He most recently served as chief of the office of structural and technical support at the US Minerals Management Service.

Liberty International Underwriters, a division of Liberty Mutual Group, is a global specialty lines business with an emphasis on niche insurance products distributed through the independent broker network.

Wärtsilä Corp.

Helsinki, Finland, has announced a joint venture agreement with Hyundai Heavy Industries Co. Ltd. to manufacture dual-fuel engines for LNG carriers. The company will be named Wärtsilä Hyundai Engine Co. Ltd., and be located in South Korea.

The technology shift towards dual-fuel machinery in LNG carriers has significantly increased demand for Wärtsilä's dual-fuel engines, with Korea holding in excess of 70% of the global market share in LNG shipbuilding. Hyundai Heavy Industries is a leading shipbuilding company.

Extreme CCTV Inc.

Vancouver, Canada, has announced the appointment of Peter Beare as managing director of its European operations.

Beare has over 15 years of executive management experience, and is well known in the UK and Europe for his service with Baxall Ltd., the UK's premier manufacturer of CCTV surveillance cameras. He also has US management experience with B&B ARMR and Ultrak.

Beare

Extreme CCTV Inc., headquartered in Burnaby, BC, Canada, specializes in the design, development, and manufacture of advanced infrared illuminators, and precision engineered video surveillance products.

GlobalSantaFe Corp.

Houston, has announced the appointment of Blake Simmons as senior vice-president, operations. Simmons will be succeeded as president of Applied Drilling Technology Inc. (ADTI), GlobalSantaFe's drilling management services subsidiary, by Steve Morrison.

Simmons is a graduate of the University of Southwestern Louisiana with a bachelor's degree in petroleum engineering, and joined Global Marine Inc. in 1983. In his new position, he has responsibility for the company's worldwide contract drilling operations.

Morrison earned his bachelor's degree in petroleum engineering from Louisiana Tech University. He held a variety of positions with Atlantic Richfield Corp. and Vastar Resources prior to joining ADTI in 1996.

GlobalSantaFe Corp. is a leading provider of offshore oil and gas drilling and drilling management services.

Statistics

Editor's note: Due to a holiday in the US, API data were not available at presstime.

OGJ GASOLINE PRICES

	Price ex tax 2-14-07	Pump price* 2-14-07	Pump price 2-15-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	176.7	216.4	224.2
Baltimore	176.7	218.6	229.8
Boston	175.1	217.0	228.8
Buffalo	178.6	238.7	247.9
Miami	185.2	235.5	247.3
Newark	177.1	210.0	226.1
New York	165.6	225.7	255.8
Norfolk	171.9	209.5	217.6
Philadelphia	190.1	240.8	243.1
Pittsburgh	171.2	221.9	236.7
Wash., DC	188.5	226.9	246.0
PAD I avg.	177.9	223.7	236.7
Chicago	197.0	247.9	256.1
Cleveland	179.5	225.9	219.4
Des Moines	174.3	214.7	219.1
Detroit	175.1	224.3	226.5
Indianapolis	184.5	229.5	216.2
Kansas City	172.9	208.9	211.8
Louisville	191.4	228.3	220.3
Memphis	167.7	207.5	222.2
Milwaukee	179.2	230.5	233.7
Minn.-St. Paul	183.0	223.4	222.2
Oklahoma City	173.7	209.1	208.1
Omaha	176.6	223.0	223.9
St. Louis	179.4	215.4	209.5
Tulsa	171.0	206.4	212.3
Wichita	172.3	215.7	210.1
PAD II avg.	178.5	220.7	220.8
Albuquerque	178.2	214.6	227.7
Birmingham	173.5	212.2	220.8
Dallas-Fort Worth	176.7	215.1	222.7
Houston	171.4	209.8	220.1
Little Rock	173.6	213.8	222.7
New Orleans	174.0	212.4	234.8
San Antonio	166.5	204.9	214.9
PAD III avg.	173.4	211.8	223.4
Cheyenne	172.5	204.9	207.8
Denver	171.6	212.0	217.8
Salt Lake City	169.4	212.3	223.5
PAD IV avg.	171.2	209.8	216.3
Los Angeles	203.6	262.1	254.1
Phoenix	189.6	227.0	234.0
Portland	204.8	248.1	213.1
San Diego	211.1	269.6	257.3
San Francisco	230.8	289.3	253.3
Seattle	206.4	258.8	234.8
PAD V avg.	207.7	259.2	241.1
Week's avg.	**181.1**	**224.7**	**228.0**
Jan. avg.	**181.7**	**225.3**	**227.3**
Dec. avg.	**184.9**	**228.5**	**216.5**
2007 to date	**181.4**	**225.0**	—
2006 to date	**186.3**	**228.7**	—

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

REFINED PRODUCT PRICES

	2-9-07 ¢/gal		2-9-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	158.75	New York Harbor	172.36
Gulf Coast	157.25	Gulf Coast	165.98
Los Angeles	185.50	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	145.32	ARA	168.81
Singapore	157.38	Singapore	172.12
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	158.38	New York Harbor	102.10
Gulf Coast	161.25	Gulf Coast	105.95
Los Angeles	193.50	Los Angeles	126.27
		ARA	92.34
		Singapore	112.08

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

BAKER HUGHES RIG COUNT

	2-16-07	2-17-06
Alabama	4	6
Alaska	11	10
Arkansas	40	18
California	34	30
Land	30	29
Offshore	4	1
Colorado	94	83
Florida	0	1
Illinois	0	0
Indiana	1	0
Kansas	12	7
Kentucky	9	6
Louisiana	202	178
N. Land	60	58
S. Inland waters	24	20
S. Land	45	36
Offshore	73	64
Maryland	0	0
Michigan	0	1
Mississippi	21	6
Montana	17	23
Nebraska	0	0
New Mexico	83	101
New York	9	4
North Dakota	33	28
Ohio	13	9
Oklahoma	178	173
Pennsylvania	14	16
South Dakota	0	1
Texas	814	691
Offshore	11	13
Inland waters	2	1
Dist. 1	24	18
Dist. 2	33	30
Dist. 3	54	61
Dist. 4	91	77
Dist. 5	154	124
Dist. 6	126	100
Dist. 7B	37	29
Dist. 7C	48	39
Dist. 8	110	70
Dist. 8A	25	35
Dist. 9	38	29
Dist. 10	61	65
Utah	45	30
West Virginia	29	25
Wyoming	73	95
Others—ID-1; NV-1; TN-5; VA-3	10	3
Total US	**1,746**	**1,545**
Total Canada	**636**	**718**
Grand total	**2,382**	**2,263**
Oil rigs	267	215
Gas rigs	1,473	1,327
Total offshore	88	79
Total cum. avg. YTD	**1,721**	**1,497**

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	2-16-07 Rig count	2-16-07 Percent footage*	2-17-06 Rig count	2-17-06 Percent footage*
0-2,500	51	—	43	2.3
2,501-5,000	102	57.8	107	42.0
5,001-7,500	228	20.1	200	15.5
7,501-10,000	417	3.8	328	4.5
10,001-12,500	408	2.9	323	1.2
12,501-15,000	272	0.7	282	0.3
15,001-17,500	117	1.7	122	0.8
17,501-20,000	77	—	64	—
20,001-over	39	—	22	—
Total	**1,711**	**8.0**	**1,491**	**6.5**
INLAND	34		36	
LAND	1,615		1,397	
OFFSHORE	62		58	

*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]2-16-07	[2]2-17-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	796	824
California	697	689
Colorado	58	60
Florida	7	6
Illinois	31	28
Kansas	95	96
Louisiana	1,402	1,172
Michigan	14	15
Mississippi	53	46
Montana	93	96
New Mexico	164	160
North Dakota	99	102
Oklahoma	171	172
Texas	1,365	1,290
Utah	44	46
Wyoming	142	140
All others	64	68
Total	**5,313**	**5,031**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	2-16-07
Alaska-North Slope 27°	49.99
South Louisiana Sweet	60.25
California-Kern River 13°	46.70
Lost Hills 30°	56.05
Wyoming Sweet	55.64
East Texas Sweet	57.52
West Texas Sour 34°	47.25
West Texas Intermediate	56.00
Oklahoma Sweet	56.00
Texas Upper Gulf Coast	52.75
Michigan Sour	49.00
Kansas Common	55.00
North Dakota Sweet	49.50

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

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

WORLD CRUDE PRICES

$/bbl[1]	2-9-07
United Kingdom-Brent 38°	57.45
Russia-Urals 32°	54.17
Saudi Light 34°	52.01
Dubai Fateh 32°	55.30
Algeria Saharan 44°	59.16
Nigeria-Bonny Light 37°	59.84
Indonesia-Minas 34°	57.74
Venezuela-Tia Juana Light 31°	53.44
Mexico-Isthmus 33°	53.33
OPEC basket	55.83
Total OPEC[2]	54.19
Total non-OPEC[2]	54.63
Total world[2]	54.38
US imports[3]	52.15

[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]

	2-9-07	2-2-07	Change
	Bcf		
Producing region	676	744	–68
Consuming region east	1,147	1,326	–179
Consuming region west	265	277	–12
Total US	**2,088**	**2,347**	**–259**
	Nov. 06	**Nov. 05**	**Change, %**
Total US[2]	**3,407**	**3,189**	**6.8**

[1]Working gas. [2]At end of period.

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

World oil balance

	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.	2005 2nd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.55	20.88	20.76	21.16	21.24	21.02
Canada	2.28	2.14	2.18	2.23	2.28	2.24
Mexico	1.99	2.02	2.08	2.10	2.06	2.11
Japan	4.81	4.78	5.96	5.46	5.03	4.94
South Korea	2.02	2.03	2.28	2.23	2.01	2.07
France	1.95	1.89	2.10	1.96	2.00	1.93
Italy	1.66	1.63	1.86	1.78	1.68	1.69
United Kingdom	1.76	1.81	1.90	1.84	1.82	1.79
Germany	2.71	2.55	2.56	2.63	2.75	2.55
Other OECD Europe	7.36	7.16	7.35	7.49	7.30	7.22
Australia & New Zealand	1.07	1.06	1.06	1.10	1.04	1.06
Total OECD	**48.76**	**47.95**	**50.09**	**49.98**	**49.21**	**48.62**
NON-OECD						
China	7.39	7.34	7.15	7.14	6.93	6.89
FSU	4.13	3.90	4.40	4.60	4.04	3.81
Non-OECD Europe	0.64	0.69	0.74	0.69	0.64	0.69
Other Asia	8.58	8.81	8.43	9.06	8.43	8.71
Other non-OECD	14.70	14.46	14.40	14.14	14.14	13.91
Total non-OECD	**35.44**	**35.20**	**35.12**	**35.63**	**34.18**	**34.01**
TOTAL DEMAND	**84.20**	**83.15**	**85.21**	**85.61**	**83.39**	**82.63**
SUPPLY						
OECD						
US	8.48	8.35	8.18	7.74	7.95	8.84
Canada	3.32	3.16	3.29	3.28	3.02	3.06
Mexico	3.71	3.79	3.80	3.75	3.72	3.89
North Sea	4.51	4.71	5.11	5.05	4.95	5.22
Other OECD	1.52	1.41	1.41	1.51	1.55	1.57
Total OECD	**21.54**	**21.42**	**21.79**	**21.33**	**21.19**	**22.58**
NON-OECD						
FSU	12.20	11.97	11.75	11.97	11.72	11.62
China	3.83	3.85	3.83	3.75	3.80	3.76
Other non-OECD	13.44	13.11	12.99	13.20	13.19	12.83
Total non-OECD, non-OPEC	**29.45**	**28.92**	**28.57**	**28.92**	**28.71**	**28.21**
OPEC	**34.19**	**33.38**	**33.90**	**34.30**	**34.55**	**34.25**
TOTAL SUPPLY	**85.20**	**84.18**	**84.26**	**84.55**	**84.45**	**85.04**
Stock change	**1.00**	**1.03**	**–0.95**	**–1.06**	**1.06**	**2.41**

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

US petroleum imports from source country

	Oct. 2006	Sept. 2006	Average YTD 2006	Average YTD 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	813	796	666	484	182	37.6
Kuwait	239	227	178	234	–56	–23.9
Nigeria	1,088	1,078	1,139	1,149	–10	–0.9
Saudi Arabia	1,382	1,564	1,456	1,560	–104	–6.7
Venezuela	1,354	1,384	1,436	1,556	–120	–7.7
Other OPEC	649	789	685	640	45	7.0
Total OPEC	**5,525**	**5,838**	**5,560**	**5,623**	**–63**	**–1.1**
Angola	536	678	526	456	70	15.4
Canada	2,144	2,262	2,262	2,134	128	6.0
Mexico	1,646	1,569	1,746	1,637	109	6.7
Norway	181	159	199	239	–40	–16.7
United Kingdom	205	239	276	401	–125	–31.2
Virgin Islands	335	396	324	329	–5	–1.5
Other non-OPEC	2,753	3,234	2,875	2,874	1	—
Total non-OPEC	**7,800**	**8,537**	**8,208**	**8,070**	**138**	**1.7**
TOTAL IMPORTS	**13,325**	**14,375**	**13,768**	**13,693**	**75**	**0.5**

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

OECD total net oil imports

	Oct. 2006	Sept. 2006	Aug 2006	Oct. 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,366	–1,146	–986	–985	–381	38.7
US	11,804	12,791	13,334	13,354	–1,550	–11.6
Mexico	–1,549	–1,713	–1,665	–1,644	95	–5.8
France	1,860	1,588	2,012	1,949	–89	–4.6
Germany	2,605	2,656	2,467	2,599	6	0.2
Italy	1,678	1,646	1,543	1,582	96	6.1
Netherlands	1,071	1,171	966	1,053	18	1.7
Spain	1,518	1,598	1,514	1,475	43	2.9
Other importers	3,999	4,313	3,860	4,015	–16	–0.4
Norway	–2,614	–2,582	–2,609	–2,963	349	–11.8
United Kingdom	248	132	324	–66	314	–475.8
Total OECD Europe	**10,365**	**10,522**	**10,077**	**9,644**	**721**	**7.5**
Japan	4,888	4,803	5,102	5,152	–264	–5.1
South Korea	1,903	2,071	2,165	2,222	–319	–14.4
Other OECD	641	650	712	797	–156	–19.6
Total OECD	**26,868**	**27,978**	**28,739**	**28,540**	**–1,854**	**–6.5**

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

OECD* total gross imports from OPEC

	Oct. 2006	Sept. 2006	Aug 2006	Oct. 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	328	395	375	455	–127	–27.9
US	5,525	5,838	5,718	5,412	113	2.1
Mexico	10	10	0	21	–11	–52.4
France	836	767	857	862	–26	–3.0
Germany	490	474	508	685	–195	–28.5
Italy	1,387	1,285	1,227	1,213	174	14.3
Netherlands	582	601	719	571	11	1.9
Spain	798	762	790	664	134	20.2
Other importers	1,324	1,446	1,256	1,383	–59	–4.3
United Kingdom	220	277	329	246	–26	-10.6
Total OECD Europe	**5,637**	**5,612**	**5,686**	**5,624**	**13**	**0.2**
Japan	4,181	4,457	4,540	4,500	–319	–7.1
South Korea	2,181	2,409	2,454	2,400	–219	–9.1
Other OECD	688	788	612	731	–43	–5.9
Total OECD	**18,550**	**19,509**	**19,385**	**19,143**	**–593**	**–3.1**

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

Oil stocks in OECD countries*

	Oct. 2006	Sept. 2006	Aug. 2006	Oct. 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	188	188	198	202	–14	–6.9
Germany	278	279	279	279	–1	–0.4
Italy	130	134	133	139	–9	–6.5
United Kingdom	103	97	98	106	–3	–2.8
Other OECD Europe	669	675	669	638	31	4.9
Total OECD Europe	**1,368**	**1,373**	**1,377**	**1,364**	**4**	**0.3**
Canada	180	181	177	173	7	4.0
US	1,767	1,786	1,764	1,716	51	3.0
Japan	654	649	641	649	5	0.8
South Korea	156	160	159	151	5	3.3
Other OECD	110	109	106	111	–1	–0.9
Total OECD	**4,235**	**4,258**	**4,224**	**4,164**	**71**	**1.7**

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

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ASSISTANT PROFESSOR OF PETROLEUM ENGINEERING
University of Missouri – Rolla

The Department of Geological Sciences and Engineering at the University of Missouri – Rolla invites applications from qualified candidates for a tenure-track assistant professor position in Petroleum Engineering. The candidate must have an earned doctorate degree in Petroleum Engineering or a closely related discipline and will be expected to teach undergraduate and graduate classes in Petroleum Engineering. Other responsibilities of the position include developing and maintaining externally funded research programs, supervising graduate student research and establishing a strong publication record. Participation in university and department activities such as undergraduate student recruitment and advising is also expected. Prior industrial experience and professional registration is preferred, but not required. All areas of specialization will be considered especially in the areas of drilling and well completions.

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Review of applications will begin March 15, 2007 and continue until the position is filled. Applicants should forward an application with resume' and names of three references to:

Human Resource Services
Reference number 00035621
University of Missouri – Rolla
113 University Center
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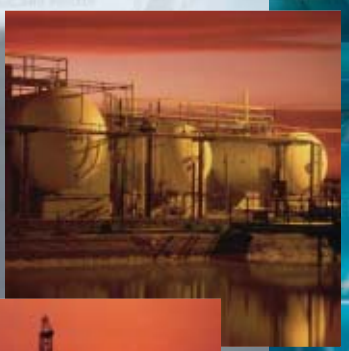

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Would politicians let Big Oil wed Little Biofuels?

Because of how they're measured, biofuel operations can seem bigger than they are.

Values for renewable fuel mandates and plant capacities typically appear in gallons per year. This year's US requirement for renewable fuel—ethanol—thus is 4.7 billion gal. Sounds impressive. But it will be just slightly more than 3% of all gasoline sold in the US in 2007.

The Editor's Perspective

by Bob Tippee, Editor

In an industry that measures its operations in barrels per day or tonnes per year, biofuel quantities require translation. To convert from gallons per year to barrels per day, divide by 15,330, but watch those zeros.

The arithmetic brings biofuel plant sizes into perspective. The average capacity of the 113 ethanol plants in operation in the US on Feb. 12 was 49.411 million gal/year. That's 3,220 b/d.

Biodiesel plants are even smaller. On a list published by the National Biodiesel Board, the largest biodiesel plant, operated by Memphis Biofuels LLC, has capacity equal to the average ethanol plant size. Most biodiesel plants are much smaller than that.

The organization puts total US biodiesel production capacity at 864.4 million gal/year (56,390 b/d). So the total capacity of the entire biodiesel industry is less than half the capacity of the average refinery in the US (131,850 b/d).

Politicians need to be reminded of these proportions when they whine, as many of them do, that oil refiners don't invest enough money in renewable and alternative energy sources, of which ethanol and biodiesel are the political favorites.

Individually, biofuel plants at current and probable sizes lack meaningful scale to businesses the size of most refiners. To make biofuels production significant to its business, a refiner must find a way to build and make money operating plants orders of magnitude larger than those in operation now. Or it must build or buy plants by the dozens.

Politicians would never stand for such a foray by "Big Oil" into ethanol and biodiesel. They'd howl about market concentration, price manipulation, tax subsidies, and other such villainies of popular oil mythology.

And they'd be the same politicians now fussing that oil companies don't spend enough money on renewable energy.

(Online Feb. 16, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Gas withdrawal fails to move market

Energy commodity prices fell Feb. 14-15 as traders in the New York market focused on a smaller-than-expected drawdown of US distillate stocks but shrugged off a near-record withdrawal of natural gas from US underground storage during the coldest week of this winter.

The March contract for benchmark US light, sweet crudes lost $1.06 to $58/bbl Feb. 14, giving back most of its gain from the previous trading session on the New York Mercantile Exchange, as the Energy Information Administration reported distillate inventories fell 3 million bbl to 133.3 million bbl in the week ended Feb. 9, vs. a Wall Street consensus for a 4 million bbl draw. However, US crude inventories dropped 600,000 bbl to 323.9 million bbl, against consensus expectation for a 1 million bbl build. That followed a loss of 400,000 bbl the prior week. Gasoline stocks were down by 2.1 million bbl against expectations for a 2.1 million bbl build.

On Feb. 15, March crude and gas contracts flirted with 2-week low prices before battling back to near-starting positions on NYMEX, despite an EIA report that same day of the second largest withdrawal ever of gas from US storage, 259 bcf in the week ended Feb. 9. It was the biggest weekly withdrawal so far this winter, larger than the consensus among Wall Street analysts, and second only to the all-time high of 260 bcf withdrawn in the week ended Jan. 17, 1997.

The related withdrawal of 179 bcf of gas from storage in the east region of the US also was an all-time high for that area, said Robert S. Morris, Banc of America Securities LLC, New York. "We believe the record withdrawal in the east region was impacted by fuel switching and infrastructure constraints," he said. That left US gas storage at nearly 2.1 tcf, 193 bcf below year-ago levels but 268 bcf above the 5-year average. "Assuming normal weather to the end of the winter season, it seems that we are heading to an ending storage level of 1.3 tcf [in March], which falls inline with the historic average. Thus, the effects of the warmer-than-normal weather in 2006 and its resulting natural gas surplus would finally dissipate," said analysts in the Houston office of Raymond James & Associates Inc.

On Feb. 15, the March gas contract traded at $7.05-7.38/MMbtu before closing at $7.29/MMbtu, up by 5.1¢ for the day on NYMEX. "Failure of the market to drop past the 2-week low of $7.05 earlier in the session may have spurred buying," said analysts at Enerfax Daily. The March crude contract traded at $56.62-58.51/bbl before closing at $57.99/bbl. That volatility was due in large part to traders covering market positions ahead of a long weekend, since floor trading at NYMEX was closed Feb. 19 for the Presidents Day holiday in the US. Moreover, the March crude contract was scheduled to expire Feb. 20.

Market outlook

The Feb. 14 data—especially the unexpected drop in gasoline inventories—were "positive for refiners," said Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va. "Total refined product inventories showed their largest week-over-week decline in over 3 months, as production and import gains were insufficient to meet increased consumption. We expect this trend of declining inventories to continue over the next several weeks, as refinery maintenance season continues, putting upward pressure on refining margins and refiner stock prices," he said.

"Heating oil is dragging down the energy complex with the combination of the winter phase-out and weather patterns that are calling for temperatures to be normal to above-normal in the last week of [February]," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. "The dollar weakness should provide some support [for energy prices]. Gold is at multimonth high and the equities continue to make new record highs," he said Feb. 14.

Based on preliminary estimates, imports of LNG into the US will likely average nearly 1.7 bcfd through January-February, "which is essentially in-line with our prior forecast, and compares with just over 1.3 bcfd, on average, during the first 2 months of last year," Morris said. He noted that natural gas prices in the US "have been nearly $2/MMbtu higher than UK prices year-to-date vs. more than $2/MMbtu lower during the same period last year." As a result, he said, imports of LNG should increase to 2.5 bcfd, or 4.5% of total estimated US gas supply. That would be "a nearly 50% uptick vs. last year, which also largely reflects increased liquefaction capacity around the globe," Morris said.

(Online Feb. 19, 2007; author's e-mail: samf@ogjonline.com)

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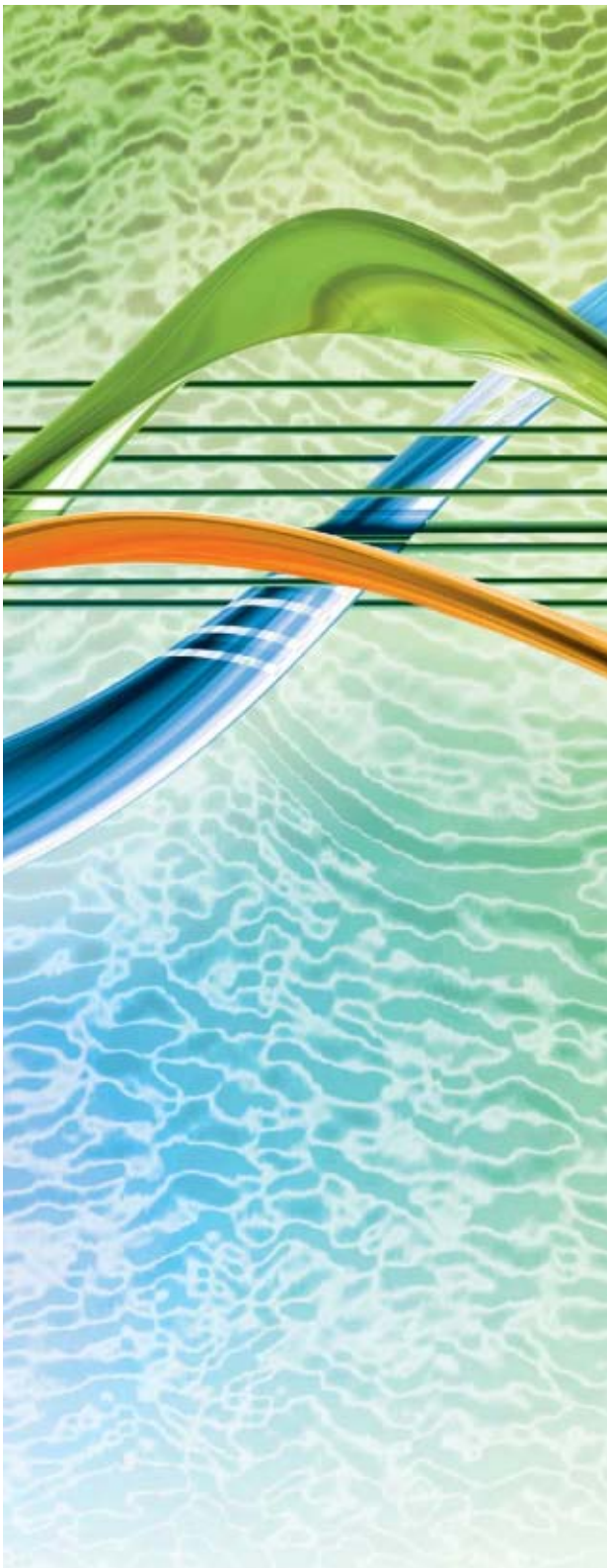

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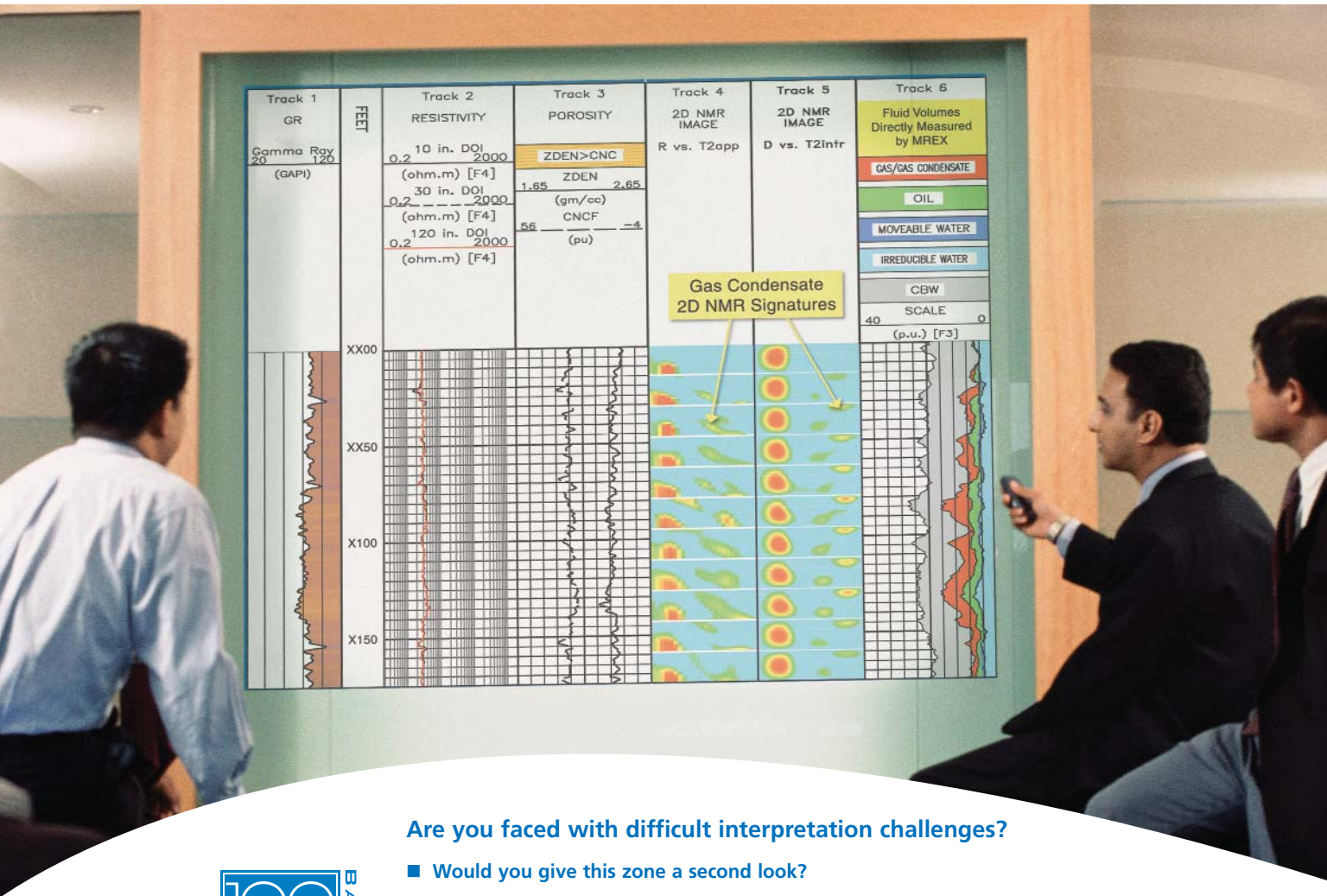

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9. Recognizing the importance of attracting young talent to the industry, DOT has established the **George Murray Award for Best Presentation by a Young Engineer** (aged 35 or younger). The future of this industry depends on attracting bright, new talent. Innovative thinking by younger engineers should therefore be recognized and rewarded accordingly. To this end, the DOT offers discounted registration fees for attendees, under the age of 35, as well as first time attendees and encourage them to submit technical abstracts for consideration.

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Drilling Equipment & Services

Supplement to *Oil & Gas Journal* • February 26, 2007

Technology Forum

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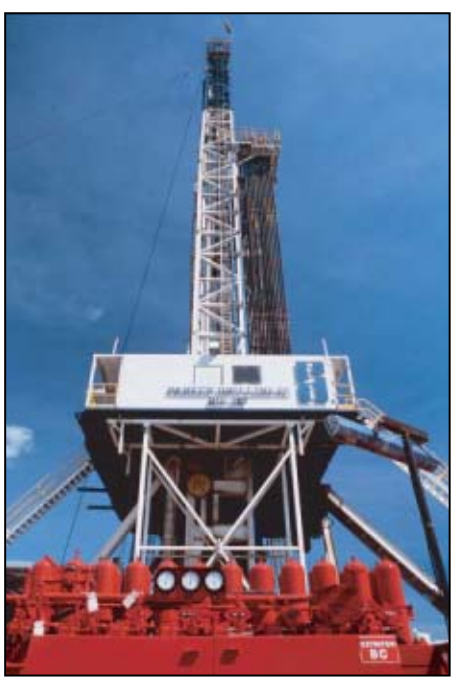

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Technology Forum

Drilling Equipment & Services

Supplement to *Oil & Gas Journal* • February 26, 2007

Parker Drilling Co. operates the world's most powerful land rig, the Yastreb, to develop Chayvo offshore oil and gas field for the Sakhalin-1 project operated by Exxon Neftegas Ltd. on Sakhalin Island in the Russian Far East. *Photo courtesy of Parker.*

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.

Bright outlook seen for global drilling industry

The outlook for a continued tight oil and natural gas supply/demand balance suggests a bright outlook for the worldwide drilling industry for the foreseeable future.

There is little danger of a broad and deep glut in global drilling rig markets emerging anytime in the near future, say industry experts interviewed for this report.

With expectations of continued strong demand in oil and gas set against persistent production declines in mature areas, industry forecasts have called for a requirement of about 100 million boe/d of oil and gas to be added to production capacity during the next 10 years, notes Claus Chur, 2006 chairman of the International Association of Drilling Contractors.

"The risk of rig oversupply is considered small; however, the drilling industry has been through so many cycles in the past that the risk of oversupply cannot be completely excluded."

— *Claus Chur, KCA Deutag*

"In my view, this can be achieved only with intensified exploration activities, enforced application of advanced production technologies, and further increases in drilling activity," he says. "So the risk of rig oversupply is considered small; however, the drilling industry has been through so many cycles in the past that the risk of oversupply cannot be completely excluded."

Chur, director, Europe, Middle East, and Russia for KCA Deutag, Aberdeen, adds that he is "certainly confident that the onshore and offshore newbuilds that are in the pipeline right now will find work at attractive dayrates,"

Land rig outlook

Jim Nixon, president and CEO of Varel International, Dallas, contends that an oversupply already exists in the two main drilling markets of North America.

"Currently, the US and Canadian markets have an oversupply of land drilling rigs. Drilling contractors, both the established and the start-ups, reacted to the very positive market signals in 2005 and early 2006 by accelerating the building of new land rigs. The newbuilds entering the market exceeded demand at the end of 2006 as gas prices settled and industry economics softened.

"We now have an event in the US market without historical precedent—active drilling rig count is rising, but dayrates are declining due to oversupply. As a result, the economics of drilling a well in 2007 appear to be improving monthly for the E&P companies. We believe by midyear 2007 North America will have a surplus of 150-200 land rigs."

The surge of new rigs into the US land drilling market could pressure day rates and profitability in 2007, says David Mannon, senior vice-president and chief operating officer for Parker Drilling Co., Houston: "However, much drilling is needed to keep US gas supplies level, so this surge may be absorbed relatively painlessly."

Aging land fleet

Worldwide, a growing majority of the global land rig fleet consists of rigs that are 20-40 years old. That begs the question of whether that situation will translate into greater retooling or more newbuilds.

"As we saw in the past," says Chur, "it is actually both. Drilling rigs do not have a specific age expectancy, if the equipment is properly maintained and replaced when necessary."

In the end, it will come down to an economic decision of what is best for a specific project, Chur adds: "I

The surge of new rigs into the US land drilling market could pressure day rates and profitability in 2007: "However, much drilling is needed to keep US gas supplies level, so this surge may be absorbed relatively painlessly."

— *David Mannon, Parker Drilling Co.*

would like to emphasize that the investment for a fully equipped 2,000 hp rig with BOP stacks, drill pipe, camp, crane, etc., is in the range of $35-40 million. So a day rate level above $30,000 is required in the first few years to justify such an investment."

A land rig oversupply might emerge in North America, suggests David Barr, group president, drilling and evaluation, for Baker Hughes Inc., Houston: "If so, this would allow the industry to retire the oldest rigs. Most of the idle US land rig fleet has been cannibalized to the point where completely new rigs are necessary to increase drilling capacity."

Nixon contends that some of the oldest US land rigs will be retired, reducing the average age of the fleet. He notes that in 1981 about half of the rigs working were less than 5 years old.

"That year, each rig drilled an average of 17 wells. Today, those same rigs are still working, but now they are 25 years older and are drilling almost 30 wells per year, yet these wells are deeper and more complex," he said. "Did the rigs change? Yes, a little; but almost all were drilling improvements that helped make these older rigs more productive came about downhole—with technological improvements in drill bits, drilling fluids, and directional drilling systems. The tools and systems operating at the end of the drillstring are what has maximized the productivity of our mature rig fleet."

Don McKenzie, president and CEO of M-I Swaco, Houston, sees the prospect of market equilibrium being tilted toward low-cost foreign newbuilds: "The US land rig market traditionally has been closed, but now we see land rigs coming from other regions, like China. Most of these rigs will be newbuilds. If they can be contracted for less than US refits, this is going to increase."

To renew the US land fleet, more newbuilds will be required, according to Mannon: "There is still a considerable amount of mechanical rigs working in the US, and, over time, these will need to be retired and replaced with newbuilds. This and natural attrition will cause about 5% of the fleet to be renewed each year, in my estimate."

Robert Bloom, senior vice-president and chief technology officer for National Oilwell Varco, Houston, concurs: "Much of the offshore and onshore fleet is old and decrepit and does not have the horsepower or capacity to be retooled or upgraded with new, more efficient technology. Therefore, much of what is being built today is replacement for current rigs. We estimate that for every two new land rigs delivered, one rig is retired."

The aging of the US land rig fleet already has resulted in a considerable number of newbuilds and refits, according to Charles Jones, executive vice-president and chief operating officer for Hydril Co. LP, Houston.

"We know this because, during the BOP oversupply situation that existed for many years, we had a portion of our business that dealt in refurbishment of used equipment through the purchase of BOP 'cores' available in the market," he says. "That business, for all practical purposes, does not exist today, as there are no longer meaningful amounts of core stock available. Today, we have more orders for new equipment destined for land rigs than we have had in 20 years."

"Customers have demonstrated a commitment to technology as a means of improving shareholder returns or value to stakeholders. Technologically advanced rigs enable operators to leverage other service company technology, such as rotary steerable systems and improved bits. We believe it will be a while before there is an adequate number of technologically advanced rigs to satisfy the requirements for more sophisticated drilling."

— *M. Alan Orr, Helmerich & Payne International Drilling Co*

Despite the North American rig surplus, demand remains strong for certain new rigs. M. Alan Orr, executive vice-president, engineering and development, Helmerich & Payne International Drilling Co., Tulsa, sees a continuing market for "value-adding" rigs and personnel.

"Customers have demonstrated a commitment to technology as a means of improving shareholder returns or value to stakeholders," Orr says. "Technologically advanced rigs enable operators to leverage other service company technology, such as rotary steerable systems and improved bits.

"We believe it will be a while before there is an adequate number of technologically advanced rigs to satisfy the requirements for more sophisticated drilling."

Offshore rig outlook

Driving a strong outlook for offshore drilling is an ongoing boom in deepwater activity.

Due to the latest deepwater boom in areas such as Brazil, the Gulf of Mexico, West Africa, and Australia, utilization rates for semisubmersibles and drillships capable of drilling deeper than 5,000 ft of water are now approaching 100%, notes Bloom.

"As a result, the pressure on operators to get rigs on con-

tract is so high that we are now seeing long-term (4-5 years) contracts in excess of $500,000 per day being achieved for some of the more modern vessels," he says.

"The forecast is for deepwater exploration to continue to expand over the next decade. With the prospect of long-term contracts and high dayrates, international drilling contractors, speculators, investors, and government oil and gas companies are investing heavily into new deepwater rig build programs.

"There are currently more than 40 deepwater vessels being built in shipyards, primarily in South Korea and Singapore. There are also some major upgrades of older semisubmersibles going on, to bring them up to new deepwater standards."

Unconventional gas

A major contributor to the surge in US drilling has been the explosion of activity directed toward developing unconventional gas resources in tight formations, shales, and coalbed methane. It has been forecast that more than 76% of new gas reserves found on land in the US will come from unconventional gas plays during the next decade.

Beyond the increased drilling, tackling the unconventional gas resource has changed the face of the US oil and gas industry, contends Nixon: "Unconventional gas ushered in the era of large independents, who, because of these opportunities, displaced the majors and are leading the way in unconventional gas plays.

"Unlocking the secrets of the Barnett, Fayetteville, and other shales was like finding elephant reserves in our own backyard, and the race to win the acreage and produce the gas carried the drilling industry through the drilling economics of 2006 and today.

"Unconventional gas accelerated the adoption of directional drilling, PDC bits, multiple zone completion tools, and massive frac jobs. It enabled operators to develop fields using the 'batch approach'—multiple wells utilizing standard-sized products—versus drilling many different wells with different types of rigs, different-sized bits, and utilizing different sized casing."

Bloom notes that unconventional gas plays are big resources for independent operators that contract hundreds of rigs with drilling capabilities of 8,000-15,000 ft.

"These rigs must also be capable of drilling horizontal laterals of up to 5,000 ft and must have the ability to rig up and move quickly and easily, because most wells are drilled in approximately 4 weeks or less between each rig move.

"This is causing the greatest increase in land rig building since the early 1980s, At this time the industry is building over 100 new land rigs, and this trend will continue for the foreseeable future."

Mannon points out that while unconventional gas plays traditionally have been highly sensitive to price, the level of E&P interest in recent finds suggests a possibility for long-term stability.

"…Five years ago, the US natural gas industry shied away from drilling into dense shale," he says. "Today, it's becoming an increasingly important source of domestic energy, due to recent advancements in technology that made drilling in these areas more cost-effective.

"Two of the top three domestic independents are focused on exploring shale formations, and another independent recently announced the discovery of a major expansion to the Barnett shale gas field and identified four new or emerging shale fields in Texas, North Dakota, and Western Canada."

Mannon notes that his company is capitalizing on the increased interest in these shale formations through its drilling and production rental tools subsidiary Quail Tools. In January, Quail Tools will open a new location in Texarkana, serving the East Texas, Oklahoma, and Arkansas markets.]

Drilling industry's top challenge: personnel needs

The most critical challenge facing the oil and natural gas drilling industry is filling an urgent need for skilled technical personnel.

Claus Chur, 2006 chairman for the International Association of Drilling Contractors, points out that last year the onshore and offshore rig fleet grew by about 350 units. To operate these rigs, about 20,000 new employees, from roustabout to toolpusher, had to be recruited and trained.

Chur, also director, Europe, Middle East, and Russia for KCA Deutag, Aberdeen, expects similar growth in 2007.

Missing generation

"Due to the cyclical nature of our industry, we have lost an entire generation of personnel through attrition starting in

the 1980s," notes David Barr, group president, drilling and evaluation, for Baker Hughes Inc., Houston. "Baker Hughes has recognized this challenge and has tripled its investment in recruitment and training resources, as well as the diversification of our workforce, and has seen the benefit of those efforts in the corresponding increase in trained new employees."

To recruit top-notch candidates and train them, Barr says that Baker Hughes has implemented global recruitment and development strategies.

"An example of our commitment to training and diversifying our employee base is the new Baker Hughes campus in Dubai, scheduled for completion in 2008. This training center will augment the Baker Hughes Education Center in Houston and training facilities in Aberdeen."

The Dubai Training Center will have capacity to serve as many as 300 employees at a time, or as many as 40,000 employees per year, Barr adds.

"I used to think my job was running equipment, but it's running people," acknowledges Keith Mitchell, vice-president, Northstar Drillstem Testers Inc., Calgary. "We are a service business, and the increased shortage in labor puts pressure on training. This makes HR a key priority to our success and the success of our industry. If we are not able to take training and HR and overall education to another level, then our industry will have trouble."

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— Keith Mitchell, Northstar Drillstem Testers

Online initiatives

Several companies report a heavy reliance on online resources to recruit and train personnel.

Charles Jones, executive vice-president and chief operating officer for Hydril Co. LP, Houston, notes, "We are looking outside the industry and in some cases outside the US to fill job functions that we might normally have seen as located in the states. Electronic information exchange is allowing us to leverage this opportunity."

"Due to the cyclical nature of our industry, we have lost an entire generation of personnel through attrition starting in the 1980s. Baker Hughes has recognized this challenge and has tripled its investment in recruitment and training resources, as well as the diversification of our workforce, and has seen the benefit of those efforts in the corresponding increase in trained new employees."

— David Barr, Baker Hughes

Baker Hughes has also expanded its online educational resources through a global learning and development initiative. Components of this initiative include an enterprise learning management system for easy access to thousands of courses on both technical and business management, and flexible learning approaches through computer and internet-based courseware.

"To shorten the learning curve, we have implemented a Field Service Desk (FSD) network to help new employees reach the desired performance level quickly," Barr says. "Our FSDs are staffed by seasoned technical representatives dedicated to improving the performance of our field workforce. In each region, FSDs define their scope differently depending on local requirements and business practices, but overall, they coordinate through the network and share best practices, standard processes and tools. This knowledge is then communicated to our employees as required to provide just-in-time technical support to expand the impact of our representatives and to accelerate the application of what we learn.":

KCA Deutag invests in a number of initiatives to train new personnel and to accelerate and assure competence, says Chur: "Training programs include our 'Safe-2-Lead' courses, with the intention of developing a standard approach to safety behavior throughout the company and the introduction of several new DART drilling simulators allowing 'hands-on' training to be undertaken in a safe, cost-effective, and realistic environment."]

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Activity surge cited in flat drilling safety record

While safety has been uppermost in the minds of drilling industry personnel for years, the industry's safety performance has been relatively flat in recent years, according to statistics tracked by the International Association of Drilling Contractors (IADC).

The lack of recent improvement in industry's safety performance is attributed to the great surge in activity and a shortage of qualified personnel, coupled with a growing emphasis on complex wells and drilling in harsh environments.

"During the past 25 years, safety performance in the drilling industry has continuously improved," says Claus Chur, 2006 IADC chairman and director, Europe, Middle East, and Russia for KCA Deutag, Aberdeen. "Keeping the trend flat in recent years is, in itself, an achievement, considering the significant increases in drilling activity and the associated recruitment and training of new personnel."

Jim Nixon, president and CEO of Varel International, Dallas, contends that, historically during drilling booms, safety suffers.

"This is due to the rapid influx of new field personnel who are reporting to newly minted field supervisors," he says. "But (and thankfully) drilling accidents have been flat in recent years, while drilling activity has been on the rise. This reduction is a testimony to the leadership and strong training programs instituted by service companies and E&P companies.

"So this year, as the rate of growth in North American drilling activity eases, we should expect safety measures to strengthen even more as personnel experience increases while hiring slows."

"Readily available, affordable, 'off-the-shelf' technologies such as rugged computers, electronics, and sensing devices have really opened the door to make modern drilling rigs much safer than their predecessors. We are confident that these innovations will continue to improve safety performance in our industry."

— *Robert Bloom, National Oilwell Varco*

Technology evolution

Much of the improvement in industry safety of the past 25 years can be laid at the doorstep of evolving technology, according to Robert Bloom, senior vice-president and chief technology officer for National Oilwell Varco, Houston.

"There are a myriad of technologies and innovations that were once considered highly specialized and experimental that are now being found on even the simplest land rigs," he says. "They are all focused on removing personnel from the inherently hazardous areas of the drilling operation. Mechanization, remote machine operation, advanced monitoring, and automation are all contributing to rigs with smaller crews and safer operating environments.

"Readily available, affordable, 'off-the-shelf' technologies such as rugged computers, electronics, and sensing devices have really opened the door to make modern drilling rigs much safer than their predecessors. We are confident that these innovations will continue to improve safety performance in our industry."

Charles Jones, executive vice-president and chief operating officer for Hydril Co. LP, Houston, concurs: "Getting people out of harm's way is key. BOP maintenance is by definition hazardous; the area you're working in is beneath the drillfloor, it's dirty, wet, and slippery. Anything you can do to minize the time you have people exposed to that will reduce

"Getting people out of harm's way is key...We introduced a new ram BOP several years ago based upon saving rig time, but we didn't realize at the time that our customers saw the value in terms of safer operations as the product reduced the time a rig hand spends beneath the drill floor."

— *Charles Jones, Hydril*

accident incidents.

"We introduced a new ram BOP several years ago based upon saving rig time, but we didn't realize at the time that our customers saw the value in terms of safer operations, as the product reduced the time a rig hand spends beneath the drill floor."

Changing culture

While technology advances have reduced risk to drilling industry personnel, a change in organizational cultures will provide the next step-change in improving drilling operations safety, says Chur.

"I do not see any specific technology that will significantly impact our safety performance in the next few years," he points out. "After a decade focusing on safer equipment and applying improved safety regulations, drilling contractors have been very successful implementing new management systems and processes designed to help people manage safety."

David Mannon, senior vice-president and chief operating officer for Parker Drilling Co., Houston, cites the company's new Quality Management System for its "unprecedented success" in safety performance in recent years. In 2006, Parker was logging record low recordable incident totals after achieving the lowest such rate among IADC members in 2005.

"We attribute this success not only to a continual emphasis on safety, but to our new QMS initiative and a world-class training facility," he says. "The focus on continuous improvement is a critical element in the approach to safety."]

Efficiencies, cost focus of drilling technology advances

An emphasis on optimizing efficiencies and keeping costs down underscores the thrust of technology advances in the drilling industry.

That emphasis is growing because the industry is pressing further into the arenas of challenging environments and complex wells. And it most do so with greater care for the environment than ever before.

Industry experts interviewed for this article weighed in on some of the key technology areas where game-changing advances are occurring.

> Within 5 years, sales for rotary steerable directional drilling systems, when paired with customized PDC products, will surpass conventional directional drilling sales.
>
> *— Jim Nixon, Varel International*

Rotary steerable systems

Rotary steerable technology helps operators but hurts drilling contractors, according to Jim Nixon, president and CEO of Varel International, Dallas.

"After being introduced commercially, drilling engineers in the Gulf of Mexico discovered that rotary steerable directional drilling could reduce the number of days drilling for a project by nearly half," he notes. "Although rotary steerable systems cost twice as much per day, only half the days were required, so total directional costs were neutral. The big savings came in offshore contract drilling costs: cutting 20 days off a drilling project could shave $4 million off the cost of renting the offshore rig.

"However, the impact has been even greater than this. An operator who wanted to drill 24 wells in the Gulf [of Mexico] for 1 year no longer needed to employ four rigs; he needed only three. In a few short years, a Gulf of Mexico market that had required 120 drilling rigs now needed only 90 to the same amount of work. The technology is now employed around the world and is growing rapidly in land applications."

Nixon contends that, within 5 years, sales for rotary steerable directional drilling systems, when paired with customized PDC products, will surpass conventional directional drilling sales.

Drill bits

Nixon sees a comparable sea change occurring in the design of drill bits.

In 2006, he notes, industry sales of PDC bits exceeded roller cone bits for the first time. In 2007, projections are that almost $2 billion worth of PDC bits will be sold, roughly double the forecast for roller cone bits.

"So what influenced this?" he asks: "The US land drilling market."

Nixon explains that "technological advances in vibration reduction, balanced design, and cutter technology have allowed

PDC bits to drill aggressively and reliably in hard, abrasive rocks, particularly those formations found throughout the US Lower 48. In recent years, these advances, which reduced the number of days drilling by 30-50%, have enabled the operator to control well costs during a time when rig rates doubled. So while operators utilized advances in drill bit technology and were drilling projects in fewer days, this only partially offset the increased rig costs.

Nixon contends that the major bit companies, including Varel, had a lock on the roller cone market due to the significant technological and economical barriers to entry.

"These barriers do not exist at nearly the same level in the PDC segment," he points out. "Here the new PDC drill bit entrants, like Varel, are giving the majors a real run for their money on both product performance and service."

Added demand for new OCTG designs caused by increased activity in extended-reach and HP/HT drilling "are key for us, a tubular goods designer and supplier, as they imply an in-depth revision of the drill stem design. The technology of 50 years ago can't meet the expectations [of today] in a safe and reliable way."

— Nicolas de Coignac, VAM Drilling

Extended-reach drilling

Many technical challenges to extended-reach drilling have been overcome, with the industry's capability now achieving access to reserves more than 6½ miles from the rig's surface location, notes David Mannon, senior vice-president and chief operating officer for Parker Drilling Co., Houston.

"Throw ratios have increased from 2:1 to 6:1 by employing special techniques for running casing; high-torque top drives and connections; high-capacity, high-pressure mud pumps; and large drill strings," he says. "Drilling rig, directional drilling, and completion technologies to date have focused mainly on overcoming drag forces preventing pipe from sliding, rotating friction forces increasing torque required to rotate pipe, and structural capacity for handling extended-well tubulars.

"Other bases of design for extreme-reach rigs include efficient and automated tubular handling, offline stand building, and increased power, hydraulic, and derrick requirements to reach total depth."

HP/HT drilling

Pursuing natural gas targets in deeper pay, such as the deep Miocene play in the shallow-water Gulf of Mexico and Gulf Coast areas, calls for equipment that can withstand the extremely high temperatures and pressures at such depths.

Key challenges in this environment have been slow penetration rates in compacted formations, an unpredictable South Louisiana pore pressure profile, long liner sections, and "breathing formations" that mask influx, according to Mannon.

The design and operation of Parker Drilling's deep barge fleet have been crucial to the success of this type of drilling program, he contends.

"Large wellbores and associated casing programs require the appropriate set-back and hookload capacity to handle, store, and run tubulars. As directional work is performed in large hole sections to take advantage of faster penetration rates and lower temperatures, the rig's capacity for handling high-volume and large-size cuttings removal and hole cleaning plays a significant role in maintaining high penetration rates and avoiding trouble time due to hole conditions.

"Engineered rig power supply, distribution, and control enables simultaneous operation of large mud pumps, top drive, and drawworks reliably for long drilling sections. Higher flow and mud circulation also impact directional and measurement-while-drilling tools, which…have flow limitations due to electronics chassis design. Reliable pulsation dampening and clean drilling fluids impact real-time measurements critical for monitoring annular pressures, deducting circulating densities, and managing pressure while drilling through formations with varying pore pressure regimes.

"As rotary steerable directional drilling expands, reliable mud pump systems facilitate downlinking to communicate revised trajectory plans to bottomhole microprocessors. Due to the significantly higher penetrations rates with fully rotational directional systems, reliable downlinking is critical to avoid sidetracking, missed targets, or downtime spent reprogramming the tools."

Underbalanced drilling

Significant advances have been made in the area of underbalanced drilling in recent years, due to its capacity to reduce lost circulation, increase drilling rates, and create higher productivity completions due to the minimization of formation damage, according to Mannon.

In southern Mexico, Parker Drilling drilled with seven large land rigs for 2 years in the Iride and Jujo Fields, he notes. "Previous wells drilled by the operator experienced severe fluid losses while drilling 8½-inch target sections in depleted, fractured zones. During the drilling campaign, underbalanced, controlled drilling was used to balance expected ECD [equivalent circulation density] based on offsets (refined while drilling), with minimum annular velocity to ensure maximum

hole cleaning."

Mannon says that several variables challenged the process on the Mexican wells, including well and reservoir pressure variables.

"To address these challenges, a broad range of drilling rates was used among several project wells with a combination of nitrogen to reduce the risk of wellbore losses. The right foam or two-phase mix was critical to prevent loading the well with excess nitrogen to eliminate the possibility of packing off or wellbore collapse. In addition, the introduction of nitrogen eliminated the possibility of formation damage, increasing field productivity."

Parker Drilling has had some success with another advance in underbalanced drilling: "mudcap" drilling—also known as closed-hole circulation drilling (CHCD). Parker's arctic barge rig 257 is currently drilling in supergiant Kashagan oil field in the North Caspian Sea, as well as the Kalamkas field appraisal well nearby.

"Previous attempts to drill to the Unit 2 formation after encountering extensive karsts in the shallower Unit 1 were unsuccessful," he says. "The CHCD technique was used as a contingency to ensure that the bit could safely penetrate both formations."

The CHCD technique applies when conventional circulation is no longer possible, Mannon explains: "It involves 'blind' drilling with the choke completely closed while using a rotating control device to seal the annulus. Mud is periodically injected into the annulus to prevent hydrocarbons and pressure from migrating to the surface. Water is continuously injected down the drill pipe while drilling."

OCTG outlook

The more demanding drilling environments also mean greater challenges for developers and suppliers of oil country tubular goods, says Nicolas de Coignac, managing director, VAM Drilling, a division of Vallourec & Mannesmann Tubes, Paris.

He notes that added demand for new OCTG designs caused by increased activity in extended-reach and HP/HT drilling "are key for us, a tubular goods designer and supplier, as they imply an in-depth revision of the drill stem design.

"The technology of 50 years ago can't meet the expectations [of today] in a safe and reliable way."

He stresses the importance of underbalanced drilling as a critical technology for the future, "as it will allow us to get some additional production out of close-to-depleted reservoirs.

"There is a true challenge there, too, as safety and reliability are compulsory features. Quality of the product (tube, connection) must be at the cutting edge of technology."

De Coignac emphasizes deepwater OCTG applications as offering the "most exciting and demanding" challenge.

> Continued development of environmentally acceptable water-based drilling fluids that match or correlate closely to the high-performance characteristics of invert emulsion fluids is having a "very significant impact" on the industry.
>
> — *Don McKenzie, M-I Swaco*

"Drilling efficiency, weight of the string, technical and environmental reliability, and real-time monitoring are some of the challenges that we must be able to respond to," he says. "For each of them, our marketing and technical support team is in very close contact with our customers' engineering departments. This relationship is key to be able to address the new technical issues with the shortest lead times."

Baker Hughes unit Baker Oil Tools has introduced what it considers a revolutionary solution to operators' casing program challenges with the world's first expandable monobore liner extension.

Baker Oil Tools Pres. Chris Beaver explains that the innovative liner extension "allows operators to drill wells that in the past may not have been commercially viable because of the typical telescoping casing design and hole size required for production. It can also allow the operator to downsize their drilling rigs but still be able to drill to the required depths with the appropriate hole size."

Drilling wastes

The management of drilling and production wastes ranks as one of the most critical issues facing the petroleum industry today, says Don McKenzie, president and CEO of M-I Swaco, Houston.

McKenzie also contends that the continued development of environmentally acceptable water-based drilling fluids that match or correlate closely to the high-performance characteristics of invert emulsion fluids is having a "very significant impact" on the industry.

Operators benefit from the value-added performance that oil-based muds deliver, while "also removing the environmental obstacles and associated costs that limit the use of oil-based fluids in many operating theaters."

Two other areas that McKenzie sees as having a profound impact on managing drilling waste are subsurface cuttings injection and dewatering, or closed-loop drilling, systems.

"The former provides operators a dedicated domain for the permanent storage of solid and liquid waste, thus eliminating the costs and long-term environmental liabilities associated with transporting these materials for off-location disposal," he says. "The latter is proving to be a viable and cost-effective alternative to environmentally suspect reserve waste pits widely used throughout the western US and elsewhere."]

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