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Oct. 23, 2006
Volume 104.40

INDEPENDENT OPERATIONS

REGULAR FEATURES

COVER

Independent producers in the US are adapting their strategies to a surge in exploration and production. The first article in the special report beginning on p. 20 spotlights a private independent's strategies for success in the Deep Bossier trend in East Texas. The second article, on p. 22, discusses the use of information to manage E&P performance. On the cover, the Nansen truss spar production platform on East Breaks Block 602 began production in 2002 in 3,675 ft of water off Texas in the Gulf of Mexico. Independent Anadarko Petroleum Co.—which became Nansen's operator after acquiring Kerr-McGee Corp. earlier this year—and Devon Energy Corp. hold equal working interest in the facility. Photo from Devon.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Sakhalin-2 environmental damage: $10-50 billion

Russia's Federal Service for the Regulation of the Use of Natural Resources (Rosprirodnadzor) estimates the cost of rectifying environmental damage at the Sakhalin-2 project at $10-50 billion.

"This sum is determined by the high cost of land reclamation and the cleaning of the seabed in the Aniva bay," said Oleg Mitvol, Rosprirodnadzor deputy head, who led an inspection carried out by the agency at the facilities of project operator Sakhalin Energy Co.

The final damage figure cannot be calculated until the end of next summer, Mitvol said, adding that the Sakhalin Energy "has not proposed any engineering solutions for eliminating the environmental violations."

Meanwhile, Russian Natural Resources Minister Yuriy Trutnev plans to visit Sakhalin on Oct. 24-26. His aim will be to determine the degree to which environmental protection legislation has been implemented at the two oil and gas deposits of the Sakhalin-2 project.

Algeria moves toward oil windfall profits tax

Algerian Energy Minster Chakib Khelil said told reporters in Algiers this month that he has received no comment from international oil companies regarding a windfall profits oil tax slated to take effect next year.

The windfall profits tax was part of a law enacted during September. The same law provides state firm Sonatrach to take a 51% interest in contracts involving IOCs.

Companies from outside Algeria will have to pay the oil tax in any month when the price of Brent crude averages more than $30/bbl. The tax rate will vary at 5-50%, depending upon a company's total production.

Anadarko Petroleum Corp., Royal Dutch Shell PLC, BHP Billiton Ltd., ENI SPA, and Hess Corp. all have oil operations in Algeria. Analysts said the companies are awaiting an explanation of the new tax structure.

Reporting of fixed-price gas deals at issue

Mandatory reporting of fixed-price gas transactions to the US Federal Energy Regulatory Commission remains an unsettled issue.

A technical conference on the subject at FERC headquarters Oct. 13 revealed lingering disagreement in the gas industry over reporting requirements discussed at a similar conference 2 years earlier.

The most significant change from 2004 came from the American Gas Association, whose members now believe mandatory reports to FERC are needed to provide a more representative market picture than exists with the current voluntary reporting to private entities that gather prices and sell the information to subscribers.

Jane R. Lewis-Raymond, vice-president, general counsel, corporate secretary, and chief compliance officer at Piedmont Natural Gas Co., said many of the 197 local energy utilities in AGA's membership believe that gas markets, while more transparent than 4 years ago, still need to be improved.

"The shift in policy occurred because we're still getting questions about confidence in prices from our customers, which suggests that the only way to increase that is to make reporting mandatory," Lewis-Raymond told commissioners and others at FERC's recent conference on markets and prices.

Chris Conway, chairman of the Natural Gas Supply Association, who also testified on behalf of the Independent Petroleum Association of America, said a 60% decline in gas prices this year shows the market is transparent and robust.

"It would be a serious miscalculation to assume that seasonal price swings and volatility indicate a lack of transparency or some other dysfunction in the marketplace," said Conway, president of the gas and power division at ConocoPhillips. "Most often, it signifies quite the opposite, sending accurate information that allows for an appropriate supply response."

Donald F. Santa, president of the Interstate Natural Gas Association of America, said that, while interstate gas pipelines have not been major gas market participants since FERC unbundled their services, "there already is tremendous transparency in the natural gas pricing transaction because of existing posting requirements for pipelines."

While the Energy Policy Act of 2005 gave FERC clear jurisdiction over commodity price reporting, he continued, the commission "should think long and hard before it crosses the threshold and uses its new authority." Santa said, noting, "Once regulation begins, it is hard to step back from it."

SPE posts reserves definitions for comment

The Society of Petroleum Engineers has posted the proposed 2007 Petroleum Reserves and Resources Classification, Definitions, and Guidelines on its web site for comment from industry.

The draft involved 2 years of work and cooperation between SPE and other sponsoring organizations: the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

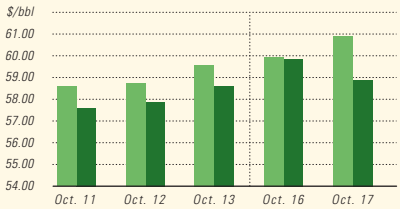
The organizations seek comment from their international memberships by Feb. 1, 2007. Later boards of the various organizations will consider final approval of the definitions.

The proposed system would update and replace guidelines outlined in the 1997 SPE-WPC Petroleum Reserves Definitions and the 2000 SPE-WPC-AAPG Petroleum Resources Classification and Definitions.

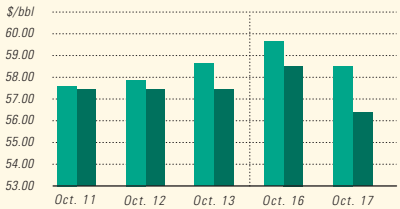
In updating the definitions, SPE's oil and gas reserves commit-

Industry Scoreboard

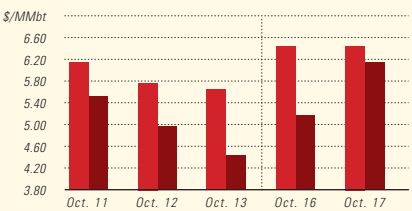
IPE BRENT / NYMEX LIGHT SWEET CRUDE



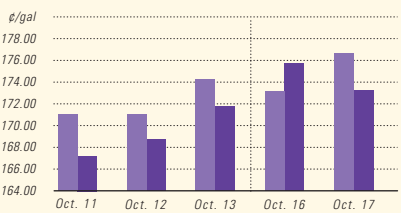
WTI CUSHING / BRENT SPOT



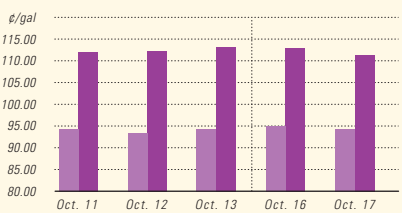
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



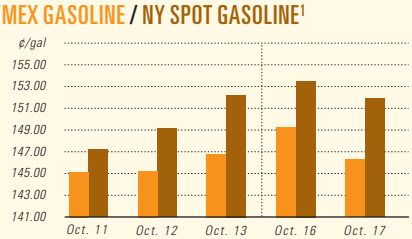
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[1]



[1]Nonoxygenated regular unleaded.

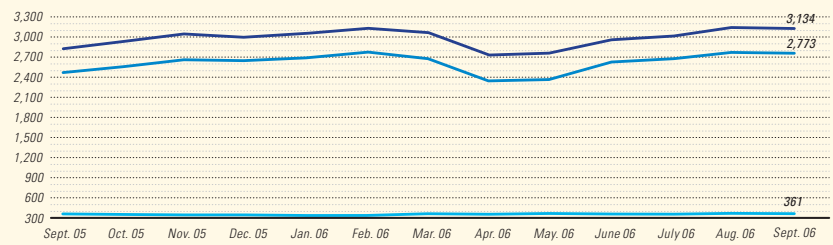
US INDUSTRY SCOREBOARD — 10/23

Latest week 10/13	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	10,289	8,951	15.0	9,801	9,115	7.5
Distillate	4,488	4,095	9.6	4,123	4,096	0.7
Jet fuel	1,582	1,610	–1.8	1,601	1,619	–1.1
Residual	575	1,009	–43.0	756	899	–15.9
Other products	5,090	4,472	13.8	4,933	4,863	1.4
TOTAL DEMAND	22,025	20,137	9.4	21,213	20,593	3.0
Supply, 1,000 b/d						
Crude production	5,176	4,230	22.4	5,105	5,175	–1.3
NGL production	2,377	1,503	58.1	2,217	1,745	27.1
Crude imports	10,897	9,218	18.2	10,298	9,996	3.0
Product imports	3,260	4,305	–24.3	3,464	3,437	0.8
Other supply[2]	1,172	1,125	4.2	1,090	1,252	–12.9
TOTAL SUPPLY	22,882	20,381	12.3	22,174	21,605	2.6
Refining, 1,000 b/d						
Crude runs to stills	15,282	13,822	10.6	15,165	15,239	–0.5
Input to crude stills	15,809	14,191	11.4	15,584	15,526	0.4
% utilization	91.2	82.8	—	90.6	90.7	—

Latest week 10/13	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	334,288	326,246	8,042	316,634	17,654	5.6
Motor gasoline	209,205	215,269	–6,064	197,905	11,300	5.7
Distillate	144,421	146,985	–2,564	124,119	20,302	16.4
Jet fuel	41,312	41,613	–301	35,984	5,328	14.8
Residual	42,090	43,602	–1,512	33,187	8,903	26.8
Futures prices[3]						
Light sweet crude, $/bbl	58.14	59.47	–1.33	63.03	–4.89	–7.8
Natural gas, $/MMbtu	6.10	6.02	0.07	13.27	–7.17	–54.1

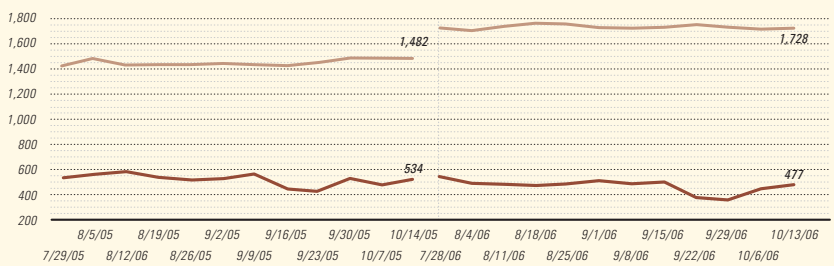
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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tee compared definitions used worldwide. The primary updates include the following:

- The system is project-based.
- The class is based on the project chance of commerciality.
- Categorization is based on quantities recovered by applying a defined project to a reservoir base case that uses evaluator's forecast of future conditions (including prices and costs, technology available, environmental standards, fiscal terms, and regulatory constraints).
- Guidelines are applicable to unconventional resources (including bitumen, oil shale, coalbed methane, and gas hydrates).

The draft definitions are posted at www.spe.org/reserves.

Statoil introduces new Asgard Blend

Statoil ASA introduced a new light, low-sulfur oil grade, Asgard Blend, based on condensate and crude from Asgard, Kristin, and Mikkel fields in the Norwegian Sea.

It consists of Asgard Crude, Asgard Condensate, and Kristin Crude, replacing the previous practice of separate crude and condensate liftings from the field, and will be marketed as a crude mix, the company said.

The oil is stored on Asgard, where the Kristin and Mikkel well streams are also processed. Output from the Asgard A oil production ship and B gas platform was previously piped to two separate stores, with Kristin production held on the Asgard C storage ship.

The first consignment of the new grade left Asgard earlier this month for Statoil's Kalundborg refinery in Denmark. The next two loadings are to go to a Dutch plant in Rotterdam and Statoil's Mongstad facility near Bergen. Statoil expects 80-90 Asgard Blend cargoes of 500,000-855,000 bbl to be lifted annually. Production is 180,000 b/d.

The Asgard Blend assay is based on samples taken from each stream contributing to the blend. Since Kristin production is not as high as expected, Asgard Blend export quality will most likely be slightly lighter than shown in assay, a difference of about 1° API, Statoil said.

Characteristics of the new crude blend are: gravity, 48.9°; specific gravity, 0.7842; sulfur content, 0.08 mass %; pour point, –27° C.; total acid number, <0.01 mg KOH/g; nickel, <0.1 ppm (wt); vanadium, <0.1 ppm (wt); viscosity at 20° C., 1.63 cst. ✦

Exploration & Development — *Quick Takes*

Norsk Hydro still awaiting Shtokman rebuff

Norsk Hydro AS—one of the companies interested in developing Shtokman gas field with OAO Gazprom in the Barents Sea—has not received official confirmation from Gazprom that its offer has been rejected, Eivind Reiten, CEO and president of Norsk Hydro told OGJ.

Speaking Oct. 16 at the inauguration of the Langeled pipeline, which delivers Norwegian gas from the Sleipner hub to the UK, Reiten said there was no timetable in place to negotiate with Gazprom until Hydro receives its communication about its status on the ambitious project.

He added: "We will discuss providing technology if that's an avenue that Gazprom wants to explore, but before I can comment any more specifically on that, we have to engage in dialogue."

On Oct. 9 Gazprom issued a press release stating that it would solely develop the Shtokman field for gas exports to Europe despite keen interest from international companies such as ConocoPhillips, Total SA, Chevron Corp., Statoil ASA, and Norsk Hydro Oil & Energy (OGJ Online, Oct. 10, 2006).

The announcement shocked the international petroleum industry, considering the technical and logistical challenges facing the project and the estimated $10-20 billion required to bring it to fruition. Hydro was viewed as holding a strong advantage over its competitors because it was experienced in developing such challenging projects; it had drilled the fourth Shtokman appraisal well with Gazprom and is providing the rig for the seventh well. The other major surprise was the loss of LNG supplies to North America, as this had been the primary original market for Shtokman gas (OGJ, Oct. 16, 2006, p. 20).

Gazprom Chief Executive Alexei Miller said earlier that the contenders had been rejected because they "were unable to provide the capital required." Miller said, "Foreign companies could not offer us assets that corresponded in size and quality with the reserves of the Shtokman field." Miller added that foreign companies would be considered "only as contractors" for the project.

Total confirms Block 17 oil find off Angola

State-owned Sonangol and Total E&P Angola reported that the Orquidea-2 appraisal well has confirmed and expanded the potential of the Orquidea oil discovery on Block 17 off Angola.

Drilled in 1,165 m of water 2 km from the discovery well, Orquidea-2 encountered the same Miocene objectives as did Orquidea-1 and also identified deeper Oligocene reservoir levels. Both the Tertiary Miocene and Oligocene objectives are oil-bearing.

The two-well success on the Orquidea structure, near the Lirio, Cravo, and Violeta finds, confirms the potential for development of a fourth production zone on Block 17, for which preliminary design is under way (see map, OGJ, Mar. 18, 2002, p. 53).

The production zone is in the northwestern area of the block and will complete the Girassol and Dalia zones, soon to be followed by the Pazflor production zone.

Total E&P is operator with a 40% interest in the block.

Lundin Petroleum to delay Caspian drilling

Lundin Petroleum AB delayed drilling the Morskoye prospect on the Lagansky block off Russia in the Caspian Sea until next year.

A two-well drilling program is scheduled to start during second quarter 2007, targeting three main Cretaceous and Jurassic reservoirs at 800-1,600 m.

Earlier this year, Lundin of Stockholm bought Valkyries Petroleum Corp., a company with exploration and producing interests in Russia and a 70% stake in Lagansky block.

Valkyries planned to spud the Morskoye well in the third quarter, but drilling was delayed pending conversion of shallow draft barges to drill in 2 m of water.

That conversion is done, but the impending onset of winter prompted the drilling delay until next year.

Anadarko produces oil from more Bohai fields

Anadarko Petroleum Corp. has started oil production from the CFD 11-6/CFD 12-1S development project off China in Bohai Bay. The development project straddles Blocks 04/36 and 05/36 in 75 ft of water.

Anadarko expects 10 wells to be producing a total 15,000 b/d by Oct. 31. Development drilling continues, with 22,000 b/d of gross oil production from 22 wells expected by mid-2007. The Bohai Bay holdings were acquired when Anadarko bought Kerr-McGee Corp., Oklahoma City (OGJ, July 10, 2006, p. 27).

The project involves producing from a gathering platform and two smaller, unmanned satellite platforms tied back 13 km to the Hai Yang Shi You 112 floating production, storage, and offloading vessel (OGJ, July 11, 2005, p. 35).

Anadarko operates the unitized development project with a 29.18% interest. ✦

Drilling & Production — *Quick Takes*

FPSO due deepwater field off Angola

BP PLC is set to install what is being called a superlarge floating production, storage, and offloading vessel on deepwater Block 18 in its Greater Plutonio fields off Angola.

The 360,000-dwt FPSO, named after the fields, is 310 m long, 58 m wide, and 32 m high.

Built by Hyundai Heavy Industries, the Greater Plutonio vessel has a storage capacity of 2 million bbl of crude oil and can handle production of about 200,000 b/d. Its living quarters can accommodate 120 crew members.

Toreador to start gas production off Turkey

With gas production scheduled to begin in late December, Toreador Resources Corp., Dallas, has entered the final stages of construction of the South Akcakoca subbasin project in the Black Sea off Turkey.

First-phase production of 50 MMcfd is expected in the first 60-90 days from startup, project operator Toreador, said.

Stratic Energy Corp., Calgary, a 12.25% interest partner, said construction of the onshore production facility is progressing well with major equipment scheduled to be on site during late October.

An 18-km onshore pipeline, already constructed and tested, links the production facility to the national grid. Toreador expects to finalize gas plan installation and precommissioning in mid-December. Installation of the offshore pipeline is scheduled to begin the week of Oct. 23 when the Regina pipelay barge is expected to arrive on location.

Most of the coated pipe has been delivered to Toreador's offshore logistics base in Eregli, and the final shipment of pipe is in transit from Italy, Stratic said. Completion of the offshore pipeline is expected in mid-December.

Meanwhile, the Prometheus jack up is completing operations on the Akkaya production tripod and has completed and tied back the three Akkaya production wells. The rig is preparing to move to the Dogu Ayazli location to install the second production tripod.

The Dogu Ayazli tripod will be floated into the field area in preparation for installation over the coming weeks. Following tripod installation and completion and tieback of the Dogu Ayazli-1 and Dogu Ayazli-2 production wells, the rig will then be moved to the Ayazli location to set the third tripod and tie back the two Ayazli production wells.

Drilling of the Dogu Ayazli-3 development well to a target on the eastern flank of the Dogu Ayazli accumulation has been delayed due to the tight schedule. In fact, the project partners are considering drilling the well after Dogu Ayazli field is on stream.

Stratic said the production platforms will be commissioned in stages, starting with the Akkaya and Dogu Ayazli platforms in December and followed by the Ayazli platform in January 2007. ✦

Processing — *Quick Takes*

Irving looks into second St. John refinery

Irving Oil Ltd., St. John, NB, confirmed that it is exploring the possibility of building a second refinery at St. John.

The project would be the first major refinery built in North America in nearly a quarter century and would be the largest private-sector investment in Atlantic Canada.

The new refinery could supply as much as 300,000 b/d of products to the US Northeast and would cost $5-7 billion to build.

Irving said it is conducting market, feasibility, environmental, and socioeconomic studies, including a site selection determination for a possible refinery.

Irving will continue to invest in its existing, 250,000-b/d refinery at St. John. That refinery, which is Canada's largest, supplies more than 75% of Canada's gasoline exports to the US and 19% of all US gasoline imports.

BP's Texas City refinery due steam generator

BP PLC plans to build a 250 Mw steam turbine power generating plant next to the existing South Houston Green Power LP cogeneration facility at BP's 446,500 b/cd Texas City, Tex., refinery.

The $100 million unit will boost total electric power generating capacity at the site to 1,000 Mw. Power not required for refining operations will be sold into the local markets, BP said.

BP's Alternative Energy business will oversee the design, construction, installation, commissioning, and start-up of the new steam generator plant, which is expected to come on stream in second quarter 2008.

Chevron to build at least three biofuel plants

A Chevron Corp. subsidiary has agreed to conduct proposal preparation for the development of at least three biofuel produc-

tion plants for Ethanex Energy Inc., a renewable energy company engaged in low-cost ethanol production.

The agreement calls for Chevron Energy Solutions (CES) to perform engineering, geotechnical studies, and site and civil design work to prepare a detailed proposal for developing and building ethanol plants that use advanced technology to maximize efficiency.

The proposal will include authorization for CES to negotiate contracts to engineer, procure, and build the biofuel plants by 2008.

The plants, which are to be built in Missouri, Illinois, and Kansas, will each produce about 132 million gal/year of fuel-grade ethanol. Currently, the total production capacity of ethanol facilities in the US is about 5 billion gal/year, Chevron said.

QP, ExxonMobil to build petrochemical complex

Qatar Petroleum and ExxonMobil Chemical Qatar Ltd. have signed a heads of agreement to progress studies for a proposed $3 billion world-scale petrochemical complex in Ras Laffan Industrial City, Qatar.

The complex will include a 1.3 million tonne/year steam cracker and associated derivative units, including polyethylene and ethylene glycol, which will employ ExxonMobil's proprietary steam cracking furnace and polyethylene technologies.

The facility will utilize feedstock from gas development projects in Qatar's North field and will serve Asia and Europe.

Start-up of the facility is expected in 2012. ✦

Transportation — *Quick Takes*

Dominion, Statoil start Cove Point LNG expansion

Dominion Cove Point LNG LP and Statoil ASA began construction Oct. 5 on facilities to almost double the capacity of Dominion Cove Point LNG terminal in southern Maryland. Capacity is being increased to 1.8 bcfd of gas from 1 bcfd and storage capacity to 14.6 bcf from 7.8 bcf. The terminal is at Lusby on Chesapeake Bay south of Baltimore.

Dominion will add two storage tanks to the five existing tanks, additional vaporizers at the plant, and two electric generator units to the existing three units.

The project also includes expanding the Dominion Transmission Inc. gas pipeline delivery system. Dominion would build a 47.8-mile, 36-in. pipeline duplicating the existing 36-in. line from Cove Point to Marshall Hall Gate in Calvert, Prince George's, and Charles counties, Md., to deliver more gas to interstate pipeline connections in Virginia.

It also will add storage capacity in Pennsylvania along with two compressor stations, a pipeline in Greene County, Pa., two sections of pipeline in Potter County, and an 81-mile, 24-in. transmission line from its Perulack compressor station in Juniata County to Dominion's South Point market hub, other interstate pipelines, and major gas storage fields at Leidy in Clinton County, Pa. Leidy is a major storage center for gas used in the US Northeast.

Dominion and a subsidiary of Statoil this summer signed 20-year service agreements for the plant expansion and increased pipeline capacity in Maryland and Pennsylvania. Statoil will provide 100% of the LNG for Cove Point. The service agreements will begin when the expansion is activated, Dominion said. Work is scheduled for completion in fall 2008.

SNG to build pipeline, expand LNG terminal

Two subsidiaries of Southern Natural Gas Co. (SNG) have filed separate applications with the US Federal Energy Regulatory Commission to build a pipeline and to expand an LNG receiving terminal near Savannah, Ga., reported El Paso Corp., Houston, SNG's parent company.

The proposed Elba Express Pipeline, to be built by Elba Express Co. LLC (EEC), will have a total capacity of 1.2 bcfd of gas. The 190-mile 36-42-in. pipeline will transport gas from EEC's Elba Island LNG terminal to Georgia and South Carolina, and to the US Southeast and Northeast via its interconnects. The Elba Island LNG receiving terminal expansion, planned by Southern LNG, will add 8.4 bcf of LNG storage capacity, which will more than double to 15.7 bcf. This expansion project will increase sendout capacity to 2.1 bcfd, representing an addition of about 0.9 bcfd.

The projects will be constructed in phases with the in-service date of the first phase of each scheduled for 2010 and the second phase of each expected to be in 2012. The estimated cost for all phases of both projects is $930 million.

Cochin to convert oil terminal to LNG use

Cochin Port Trust (CPT), the Indian government department that manages the port of Kochi, reported plans to convert the existing oil terminal into a receiving terminal for LNG.

According to CPT Chairman N. Ramachandran, Indian Oil Corp. (IOC) has approached CPT with a proposal to provide an exclusive terminal to handle imported LNG.

"We have already had three rounds of discussions with IOC and will soon finalize the proposal," Ramachandran said.

"There is some urgency in converting the oil terminal to LNG, since the Single Point Mooring project of Bharat Petroleum Corp. Ltd. (BPCL) at Puthuvypeen (near Kochi) will be commissioned by next year."

After the commissioning of the SPM project, CPT's oil terminal would become superfluous. BPCL would no longer use it, and the port would lose almost 40% of its total earned revenues.

Converting the terminal to handle LNG, with or without a regasification facility, would bring CPT substantial revenues, because Petronet LNG's Kochi terminal is still on the drawing-board and will require at least 2 years more to become operational.

"IOC could take imported bulk LNG from the port to its bottling unit at Irimpanam, from which it can be redistributed," said Ramachandran. Currently, the company is importing LNG through New Mangalore port for distribution in the four southern states.

CPT also is exploring the possibility of optimum utilization of the land available on Willingdon Island, where the port is located. Unlike other ports, land shortage is a major concern with Cochin. ✦

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Calendar

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

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

OCTOBER

IPAA Annual Meeting, Grapevine, Tex., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 23-25.

Power-Gen India & Central Asia Conference, New Delhi, (918) 831-9160, (918) 831 9161 (fax), e-mail: registration@pennwell.com, website: www.pgen.events.pennnet.com. 24-26.

DryTree & Riser Forum, College Station, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.drytreeforum.com. 24-26.

West China International Oil & Gas Conference & Exhibition, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-27.

Annual Condensate & Naphtha Forum, Phuket, +65 6222 0230, +65 6222 0121, e-mail: condensate@cconnection.org, website: www.cconnection.org. 30-31.

Chad International Oil & Gas Conference, N'Djamena, +44 207 596 5148, +44 207 596 5071 (fax), e-mail: colins.tchanga@ite-exhibitions.com, website: www.african-events.com. 30-31.

API Fall Refining and Equipment Standards Meeting, San Francisco, (202) 682-8000, (202) 682-8222 (fax), e-mail: petroteam@api.org, website: www.api.org. Oct. 30-Nov. 1.

Carbon Capture and Storage in the UK Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 31.

NOVEMBER

AAPG International Conference and Exhibition, San Juan, (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 4-7.

AAPG International Conference & Exhibition, Perth, (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 5-8.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, +971 2 4446900, +971 2 4446135 (fax), e-mail: adipec@adnec.ae, website: www.adipec.com. 5-8.

Purvin & Gertz Latin America LPG Seminar, Panama City, (713) 236-0318, (713) 331-4000 (fax), website: www.purvingertz.com/seminars. 6-9.

Oil Depletion Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 7.

IADC International Well Control Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 7-8.

Annual Petroleum Exhibition & Conference of Mexico, Villahermosa, (713) 529-1616, (713) 821-1169

(fax), e-mail: sales@ieimail.com, website: www.oilonline.com/mexico. 7-9.

International Marine Gas CNG Standards Forum, St. John's, Newf., (709) 754-9880, (709) 754-9881 (fax), e-mail: info@cmcng.com, website: www.cmcng.com. 7-9.

International Petroleum & Petrochemical Exhibition, Beijing, (301) 493-5500, (301) 493-5705 (fax), e-mail: stout@ejkrause.com, website: www.ejkcn.com/ippe06/ippe06.htm. 7-10.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 8.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 9.

AIChE Annual Meeting, San Francisco, (212) 591-7338, (212) 591-8894 (fax), e-mail: meetmail@aiche.org, website: www.aiche.org. 12-17.

ERTC Annual Meeting, Paris, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

IADC/SPE Asia Pacific Drilling Technology Conference, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 13-15.

Gulf Coast Well Control Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: kharli@pe.tamu.edu, website: http://WellCTRL.org. 15-16.

Annual Unconventional Gas Conference, Calgary, Alta., (403) 218-7721, (403) 920-0054, e-mail: info@csug.ca, website: www.csug.ca. 15-17.

European Biofuels Forum, Warsaw, 0044 20 7067 1800, 0044 20 7430 9513 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.wraconferences.com/wra112overview.html. 21-22.

PETEX Conference & Exhibition, Olympia, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: petex@pesgb.org.uk, website: www.pesgb.org.uk. 21-23.

International Symposium on Protective Coatings, Bombay, 022-25767891, 022-25723480 (fax), e-mail: khanna@iitb.ac.in. 24-26.

Petrochem Arabia Conference, Dubai, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 26-27.

IADC Drilling Gulf of Mexico Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

Power-Gen International Conference, Orlando, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pgen.events.pennnet.com. 28-30.

Ethanol Summit, Houston, (207) 781-9617, (207) 781-2150 (fax), e-mail: cgroff@intertechusa.com, website: www.intertechusa.com. Nov. 30-Dec. 1.

DECEMBER

Independent Operators Forum, London, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.operators-forum.com. 4-6.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 4-6.

GASTECH International Conference & Exhibition, Abu Dhabi, +44 (0)1895 454 592, +44 (0)1895 454 584 (fax), e-mail: info@gastech.co.uk, website: www.gastech.co.uk. 4-7.

Renewable Energy in the New Low Carbon Britain Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 5.

Calendar

OSEA International Exhibition & Conference, Singapore, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 5-8.

Annual CO2 Flooding Conference, Midland, Tex., (432) 552-2430, (432) 552-2433 (fax), website: www.spe-pb.org. 6-8.

Annual China Gas Conference, Beijing, 65 6536 8676, 65 6536 4356 (fax), e-mail: marcy.chong@abf.com.sg, website: www.abf-asia.com. 11-12.

2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: oaconference@pennwell.com, website: www.offshoreasiaevent.com. 16-18.

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8223 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 23-25.

SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

Russia Offshore Oil & Gas Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 7-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multiphasepumping.com. 10-13.

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.

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 12-13.

IP Week, London, +44(0) 20 7467 7100, +44(0) 20 7580 2230 (fax); e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 12-15.

✦ Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: info@clarion.org, website: www.clarion.org. 12-15.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 14-15.

SPE/IADC Drilling Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

AustralAsian Oil Gas Conference and Exhibition, Perth, (704) 365-0041, (704) 365-8426 (fax), e-mail: sarahv@imexmgt.com, website: www.imexmgt.com. 21-23.

Pipe Line Contractors Association Annual Meeting, Aventura, Fla., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 21-25.

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

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.

Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-8.

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

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

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, website: www.nace.org. 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.

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.

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. 28-29.

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.

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.

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.

✦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.

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.

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

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.

API Spring Refining and Equipment Standards Meeting, Seattle, (202) 682-8000, (202) 682-8223 (fax), website: www.api.org. 16-18.

API/NPRA Spring Operating Practices Symposium, Seattle, (202) 682-8000, (202) 682-8223 (fax), website: www.api.org. 17.

API Annual Pipeline Conference, Albuquerque, (202) 682-8000, (202) 682-8223 (fax), website: www.api.org. 17-18.

Russia & CIS Bottom of the Barrel Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 18-19.

American Institute of Chemical Engineers Spring National Meeting, Houston, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 22-26.

EnviroArabia Environmental Progress in Oil & Petrochemical Conference, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 23-25.

IPAA OGIS East Conference, New York, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 23-25.

International Conference & Exhibition on Liquefied Natural Gas, Barcelona, +34 93 417 28 04, +34 93 418 62 19 (fax), e-mail: lng15@lng15.com, website: www.lng15.com. 24-27.

SPE Research and Development Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-27.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. Apr. 30-May 3.

MAY

NPRA National Safety Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 2-3.

Annual Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-15.

AchemAsia Exhibition and Conference, Beijing, +49 (0) 69 7564 249, +49 (0) 69 7564 201 (fax), e-mail: achemasia@dechema.de, website: www.achemasia.de. 14-18.

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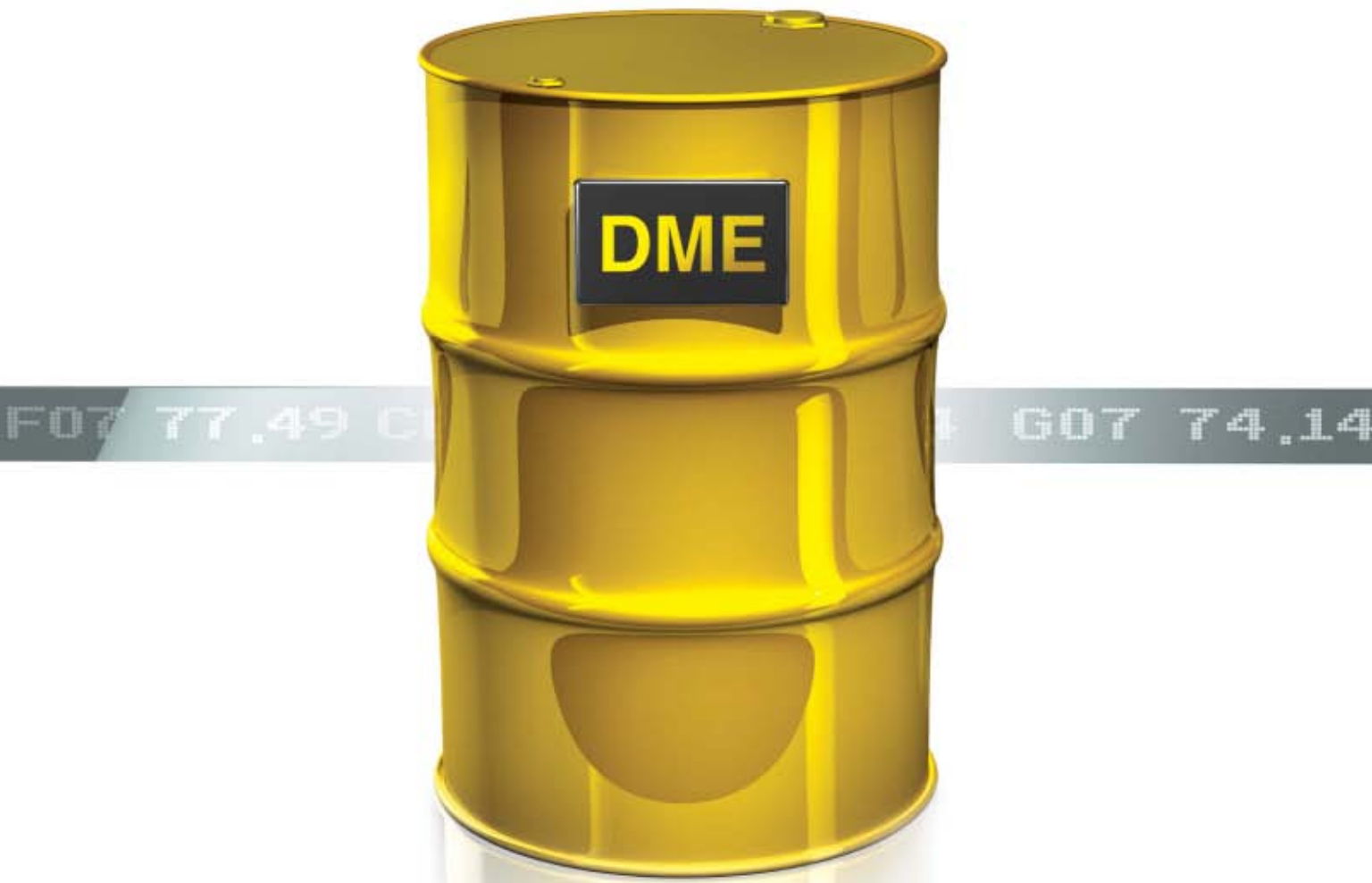

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The Dubai Mercantile Exchange Limited (DME) is planning to operate as an exchange inside the Dubai International Financial Centre (DIFC) and have the New York Mercantile Exchange Inc. provide its clearing and settlement services. Before this happens the DME must obtain regulatory approval from the Dubai Financial Services Authority (DFSA). This means that the DFSA must first license the DME as an Authorised Market Institution to operate as an exchange in DIFC and must recognise the New York Mercantile Exchange Inc. to operate as a clearing house in the DIFC. The US Commodity Futures Trading Commission must also give it approval. Until the above regulatory approvals have been granted no trading on the DME will be permitted and no person will be admitted as a member of the DME.

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Journally Speaking

New look at gas hydrates

Paula Dittrick
Senior Staff Writer

Geologists have long speculated that naturally occurring hydrates contain immense volumes of natural gas. But production of gas from gas hydrates under the world's oceans and in its arctic regions remains uneconomic.

Hydrate experts suggest industry-oriented research during the next several months could yield knowledge crucial to unlocking gas hydrates, whose development is compared with that of coalbed methane—a gas source considered uneconomic 20 years ago.

US Geologic Survey research geologist Timothy S. Collett of Denver acknowledges much remains to be learned about the geologic, engineering, and economic aspects of hydrates—a crystalline combination of gas and water.

Still, he said producing gas from hydrates no longer seems to be a distant goal. This is because gas hydrate energy assessments accelerated during the past 5 years as rising gas prices have stimulated interest in the subject.

"There is a realization that this unconventional resource could be developed in conjunction with conventional gas fields," said Collett, who recently returned from India, where the USGS was an advisor to the Indian government on hydrate research. India's objective is production from gas hydrates by 2010.

Various government agencies worldwide and international consortia verified gas hydrate accumulations. Japan, Canada, the US, and India have hydrate research programs (OGJ, Oct. 16, 2006, p. 26). China, South Korea, Norway, Chile, and Mexico are contemplating government-sponsored hydrate research.

Gulf of Mexico

Hydrate expert Arthur H. Johnson of Kenner, La., said research is progressing faster than some people are discarding old misperceptions.

He disputes the notion that the Gulf of Mexico has no significant gas hydrates based on the fact that seismic surveys show few obvious bottom-simulated reflector (BSR) results (OGJ, Apr. 25, 2005, p. 52).

BSRs have been used in many areas to infer the occurrence of gas hydrates.

"It had been said that there is no hydrate beneath the sea floor in the Gulf of Mexico," Johnson said. "That is wrong. You might not get a good BSR where you have decent reservoir rocks.... The idea of hydrates being just a BSR hunt has gone by the wayside."

Other seismic indicators suggest substantial volumes of gas hydrates in the gulf's deepwater upper sediment, said Johnson, chairman and chief executive officer of Hydrate Energy International.

Johnson also serves on the US Department of Energy's Methane Hydrate Advisory Committee and the American Association of Petroleum Geologists Gas Hydrate Committee.

"We use the term petroleum systems approach to gas hydrates," Johnson said. "The critical questions that need to be answered involve the ultimate amount of gas that can be recovered from hydrates by each well, the daily production rate of each well, and the expenses involved."

Chevron Corp. led a Gulf of Mexico joint industry drilling program that drilled two locations 18 months ago, primarily to improve understanding of drilling safety issues related to gas hydrates. Study participants plan more drilling, possibly next year, to assess the commercial potential of gas hydrates.

"Researchers mapped areas where they believe there are sands within the hydrate stability zone that would lead to commercial development," Johnson said. "The next drilling program would test that model."

The US Minerals Management Service is conducting a study using a stochastic, or probability-based, methodology to estimate the in-place and technically recoverable gas hydrate energy resource potential for the Outer Continental Shelf (Gulf of Mexico, Pacific, Atlantic, and Alaska).

Preliminary results and the methodology will be released around yearend or early next year, said Pulak K. Ray, MMS Resource Evaluation Division chief geologist.

Alaska

Alaska's North Slope is another proven exploration target for gas hydrates. BP Exploration (Alaska) Inc. and the DOE are working jointly to characterize North Slope hydrate resource potential within existing industry infrastructure.

The study, in which USGS is a participant, is assessing the commercial viability of gas hydrates in the Milne Point area of northern Alaska.

BP had planned a stratigraphic test for earlier this year in the Eileen gas hydrate trend, but rig delays led to the well's deferral. The drilling and test program is expected to take 20-25 days and tentatively is scheduled for early 2007.

Both Collett and Johnson suggest that potential US production of gas from hydrates is likely to start in Alaska. Meanwhile, the timing for commercial production of gas from hydrates remains uncertain.

Johnson believes it's conceivable that commercial production could begin, at least on a limited basis, within 5 years. ✦

Editorial

A dot-com energy vision

During the easy-come, easy-go dot-com craze of the 1990s, talk abounded of a new economy. It was an economy in which cash "burn rates" mattered more than profitability, in which information worked as currency, in which physical assets counted for little. People made a lot of money at the dawn of this new economy. They lost it when reality struck.

Like the ill-fated new economy, a new energy vision has taken wispy form in the popular US imagination. It's a vision quivering with hope for energy independence, renewable supply, and no environmental consequence. It's a vision that can make a Republican president talk like a Democrat.

Vision vs. choice

The new energy vision clashes with fuel choice by the market, which has had a good run in the US. After price controls and manipulations imposed by the National Energy Act of 1978 gave way to reality, oil and gas prices vacillated for a quarter of a century in a range that, usually, encouraged production and allowed consumption to grow. Excursions outside this range of comfort never lasted long. Oil and gas attracted little attention except to the extent their production and use affected the environment. Energy consumers enjoyed ample supply and low prices.

Because prices recently have risen in an evident market correction, however, politicians from both major political parties now want to nationalize fuel choice. The abrupt change of political mood threatens to generate endless policy mischief. It was on display Oct. 12 in a speech by President George W. Bush at a renewable-energy conference in St. Louis.

"We're too dependent on oil," he declared in a reprise of the "addicted to oil" theme from his 2006 state-of-the-union address. The statement raises important questions. How dependent is "too dependent?" What's the basis for this judgment? Where, in fact, does the Constitution give the president responsibility for assessing oil dependency?

These questions could be ignored if Bush's assertion of a national problem didn't lead him into potentially expensive ideological territory. Has the president forgotten that government energy prescriptions usually cost too much and seldom work?

In the president's view, the problem isn't only that the US is "too dependent on oil," whatever that means. There's also national security, Bush reminded his audience in St. Louis. "We get oil from some countries who don't particularly care for us." And this is relevant to—exactly what? Mutual adoration has never before been a precondition of commerce. Why make it one now? In fact, business can stabilize international relations when governments don't use it as a cudgel. Reciprocal economic needs deserve more attention than they receive as influences on national behavior and factors in the security of energy supply.

"This country has got to use its talent and its wealth to get us off oil," Bush insisted with no mention of how much this ambition might cost energy consumers. Then he went on to boast about money he's committing the government to spend on hybrid vehicles, battery technology, hydrogen as a vehicle fuel, and, of course, renewable energy. He further asserted the need for the government to change American behavior. "We've got some interesting initiatives at the federal level to help change habits," he promised. What's most interesting, in fact, is the confusion evident in a Republican president who feels compelled to manipulate individual behavior.

Which party?

To his credit, Bush did speak of the need to increase domestic production of oil, gas, nuclear power, and coal—energy sources with much greater supply potential and much less need for subsidies from taxpayers than the less traditional fuels on his wish list. All in all, though, he sounded on energy, less than a month before a pivotal national election, like a Democrat. No wonder Republicans are worried.

That this can happen is important beyond political outcomes. A market adjustment is no reason to usurp economics. It's no reason to throw public money at uncompetitive energy forms. It's no reason to adopt the energy equivalent of dot-com economic fantasies. And it's no reason to limit freedom of economic choice. ✦

POINT OF VIEW

Leor Energy blends old-school ways, unconventional gas

Steven Poruban
Senior Editor

Guma Aguiar, vice-chairman and chief executive officer of private Houston independent Leor Energy LP, took an interesting and unusual route to finally work in the oil and gas industry.

Unlike many executives in the exploration and production business, Aguiar didn't start with a background in oil and gas. Instead, he worked first in 1999 as a clerk on the floor of the New York Mercantile Exchange with a focus on energy markets, especially gas, then dabbled in trading.

Aguiar later joined his uncle, Thomas Kaplan, to manage family investments ranging from venture capital to private equity and debt. It was during this time that he became responsible for creating a US company focused on aggressive oil and gas exploration.

"I made an investment in an oil and gas start-up company with my uncle. We had some fairly good success early on and decided that this was something that we would like to do," Aguiar told OGJ.

After forming a partnership with his uncle in 2003, Aguiar moved to Houston to start looking for other deals.

"This is one of those 'old school-type' success stories," Aguiar says. "I had a little bit of money that I'd saved, and [Kaplan] put some money up as well. We started looking for some properties in North Louisiana and East Texas."

Growing from concept

A breakthrough came when Aguiar met a geologist in his 70s who had a concept for a gas play with very little data to support it. The geologist was John Amoruso, and the play was what later would be called Amoruso gas field in Robertson County, Tex., in the Deep Bossier trend.

Until that point in 2003, Aguiar says, "Few companies had drilled any Deep Bossier wells, and I do not think any company had had any success."

Aguiar recalls Amoruso's concept as it was drawn on a chalkboard in front of him: "[Amoruso] had this concept that the gas was coming off the shelf edge, and it formed thick sand packages."

Encouraged by the geologist's ideas, Aguiar led Leor through a period of heavy acquisition. Leor continued acquiring acreage in the Deep Bossier play for 6 months when the former Burlington Resources Inc. (now part of ConocoPhillips) was gaining success in the region.

By the time Burlington drilled its first Deep Bossier well, Leor held the lion's share of the trend's acreage. Aguiar credits companies like Burlington for calling industry attention to the play. "At that point, they were basically our best promoter," he says.

Chance for success

Leor tried to ensure that it dominated the fledgling play. This month marks a year since Leor drilled its first well in

"I made an investment in an oil and gas start-up company with my uncle. We had some fairly good success early on and decided that this was something that we would like to do."

—Guma Aguiar, vice-president, chief executive officer, Leor Energy LP

Aguiar says of the deal's beginnings: "EnCana has done an excellent job of operating these wells, which are very, very complex: high-temperature, high-pressure, and deep. It's one of those things where we thought they would be the best in the business."

This deal was important to Aguiar, he says, because entering into this sort of transaction gave Leor access to EnCana's vast experience and expertise in drilling and completing the unconventional gas wells, which was important because the Deep Bossier wells Leor and EnCana are drilling at Amoruso field are "different from conventional Bossier wells, and much different from Barnett shale wells," for example.

"You don't know when you're going to see a kick because there's so many different sand packages," he says.

Working with EnCana, Aguiar has access to skills of former Tom Brown Inc. and Matador Resource Co. workers with experience drilling for unconventional gas.

High exposure

Leor and EnCana Oil & Gas (USA) Inc. expect to have drilled 22 wells in Amoruso gas field by yearend (OGJ Online, July 28, 2006).

Currently, says Aguiar, the joint field owners have five rigs working in the Deep Bossier trend and expect two more to arrive in the next 45 days. Aguiar said, "If we continue to have success like we are having, I think it may be appropriate to add even more rigs in 2007."

Aguiar says that in a $10-12/MMbtu gas environment, he would like to have more rigs working the area. Even with gas prices in the $5-6/MMbtu range, however, he thinks Leor's high-risk, high-cost operations are economic.

"We're pretty exposed to gas prices," Aguiar says. "With our history and the fact that we brought production on so fast, we're really not in a position to hedge."

In the short to medium term, Aguiar plans to raise more equity and possibly bring more partners on board. Currently he and his uncle control most of the company but would consider taking the company public in 2007-08.

"Technically and operationally, we're extremely sound," Aguiar says. "The guys that I brought on to work for me here are masters of their trade. We had the benefit of really selecting the best the area. Since that time, the company has been able to ramp up production from 6 MMcfd of gas to about 100 MMcfd. "For onshore North America, that's unheard of," Aguiar says.

In July 2005, Leor cut a fateful deal with the US subsidiary of EnCana Corp. of Calgary to jointly explore and develop its Robertson County acreage.

Then in January, Goldman Sachs Principal Strategies Group led a $45 million equity investment giving the participating investors a minority interest in Leor.

And in June, Leor sold 7,400 net acres in its Amoruso field acreage to EnCana for $242.9 million in cash and 4,039 net acres adjacent to its Amoruso leasehold. Leor now holds interests in about 50,000 gross acres in Robertson County and 150,000 gross acres in the Deep Bossier trend.

Career highlights

Guma L. Aguiar, cofounder of Leor Energy, has served as vice-chairman and chief executive officer since the company's inception.

Employment

Aguiar began his career as a clerk on the floor of the New York Mercantile Exchange. Aguiar joined his uncle, Thomas Kaplan, to manage family investments in 2001. During this time he was given responsibility for creating a US company focused on oil and gas exploration. After assembling a lease position in Louisiana and Texas ranging from unconventional natural gas to shallow oil, in 2003 Aguiar identified and executed the company's acquisition of its flagship property in the Deep Bossier trend of East Texas.

Education

Aguiar attended Clemson University, where he studied business administration.

Affiliations

Aguiar is chairman of the Lillian Jean Kaplan Foundation and is involved in numerous philanthropic activities.

guys to add value to the company."

The company's chief financial officer, as an example, was a Solomon Smith Barney banker for 17 years. Everyone on our management team, says Aguiar, himself just 29 years old, has 25 or more years of oil and gas experience.

In the Deep Bossier play, Aguiar says, things can only get better. "Over the course of time, as we drill more wells and better understand what's going on there, we will be able to cut costs and bring our wells on line with better economics."

In the family

Aguiar appreciates the experience of working with his uncle. "In today's world you just don't see too often two family members being able to partner up and be so successful and have such a great relationship and make a lot of money along the way," he says.

"One thing that people have noticed about Tom and I is that we're sort of like throwbacks to the old days—we do a lot of deals on handshakes."

Aguiar says the family feeling extends to employees. "You don't come to work for the company; you come and join the family. It's not just the money for us. It's thinking about people and caring about them." ✦

Managing E&P performance with improved information

William F. Aimone III
Deloitte Consulting LLP
Houston

With oil and natural gas prices hovering at all-time highs, shareholders' return on investment over the past decade have been an astounding 14% average annual return (AAR). However, not all exploration and production companies are enjoying similar returns. The E&P firms leading the pack are averaging ROI of 22% AAR, whereas companies in the lowest quartile are averaging 10-year stockholder returns of just 8%.

Why are some upstream companies able to achieve almost three times the level of stockholder return than other upstream companies? The "on-the-surface" causes of the differing ROIs include the makeup of producing property portfolios, debt structures, geographic scope, and economic valuation standards. Although "on-the-surface" contributing factors for achieving "better-than-average" success in the E&P market varies, there are underlying internal reasons for better-than-average success.

It is neither by coincidence nor by dumb luck that some E&P firms have sustained higher return portfolios versus the industry average. Executive management in better-than-average companies have made decisions based upon the right information, at the right time, with the right resources to maximize their asset portfolios. Simply put, the more successful companies were equipped to execute their strategy.

Performance management

Equipping E&P companies to execute their strategy is not simple. E&P firms work in complex environments and have equally complex corporate structures that can lend themselves to silos. Better-than-average E&P companies have developed various internal programs to obtain the right information to manage internal performance and track progress toward the defined strategies.

Most of the internal programs fall under the category of what is termed "performance management." The mere mention of the words performance management raises the specter that many experienced during the mid-1980s when "management by objectives" was the rage. This experience typically started with the dissecting of financial and operational reports to identify, for example, how much it costs to buy a pencil. These irrelevant costs were then used to measure executive performance and dole out nonexistent bonuses. Performance management has come a long way since then.

In the upstream environment, performance management spans the organization incentives, processes, and technologies related to managing the company assets—from economic valuation, planning, budgeting, and forecasting to asset evaluation, production analysis, capital tracking, reporting, and linking compensation to performance.

Performance management includes programs such as improving the quality and timeliness of production information, improving the accuracy of forecasting reserves, generating new drilling or completion opportunities from the information hidden in current field data capture, production accounting, general accounting, drilling management, and economic systems.

The ultimate goal of the performance management programs is to help

management steer the organization to a better-than-average (or higher) return on assets through reduction in lease operating expenses, improved reserve replacement, increased production, and reductions in general and administrative costs.

Importance of information

At the heart of the performance management programs is access to more timely, relevant, accurate, and consistent information.

Traditionally, and still today, E&P companies have relied on a variety of stand-alone systems and spreadsheets to generate information about overall investment and asset performance: Economic systems provide volume forecasts and reserve estimates, field data-gathering systems capture volumes, oil field workstations generate gross daily production estimates, revenue-accounting systems generate sales volumes and the plethora of spreadsheets the company uses to track and report the information.

Field operations rely on the oil field workstations, spreadsheets, and phone calls to their pumpers to gather daily production estimates for their properties. Marketing relies on inconsistent data from their marketing systems plus phone calls to various regions to get the accurate view for nominations.

To navigate through this information labyrinth, management typically has to wait several days to see production results. A reasonable picture of capital spending takes weeks to calculate via spreadsheets. Not surprisingly, the economic models produce lease operating expense assumptions inconsistent with the operations view of lease operating requirements. Variances between production volumes and sales volumes are attributed to "shrink" or the "unknown." Finally, executive management waits several weeks for their revenue systems to be updated to see the monthly financial results.

Meanwhile, on the drilling side of the business, drilling systems are used to capture most of the capital spending; however, much of the tracking process is supplemented with spreadsheets and personal databases to help engineers estimate their projected spend on workover and drilling projects. To make matters worse, many of the projected spend estimates are not sufficient for finance to accurately project cash flows.

From an overall financial perspective, tying drilling and production activity to the financial results is—as an understatement—a challenge. The relationships between properties, wells, and divisions in the financial systems do not typically align with the relationships in the production, capital, and economic databases. The data relationships cause a challenge in analyzing and correlating the operational impacts with financial results. Consequently, the financial statements become a mystery to most of operations, and disconnects between operations and finance are created.

In sum, upstream companies traditionally have struggled with tying together business performance information to allow them to improve their understanding of production and sales variances, and to project cash outlays and tie in operational results to financial results.

Overcoming information gaps

Traditionally, E&P firms have attempted to overcome the information gaps with a sea of spreadsheets containing multiple versions of the truth, created by people who are taken away from their real job of running the business.

How can today's leading upstream companies address the information challenges related to performance management?

Deloitte Consulting LLP has helped a number of upstream companies address these challenges and determined that they must address four dimensions of information and performance management: organization, process, data, and delivery.

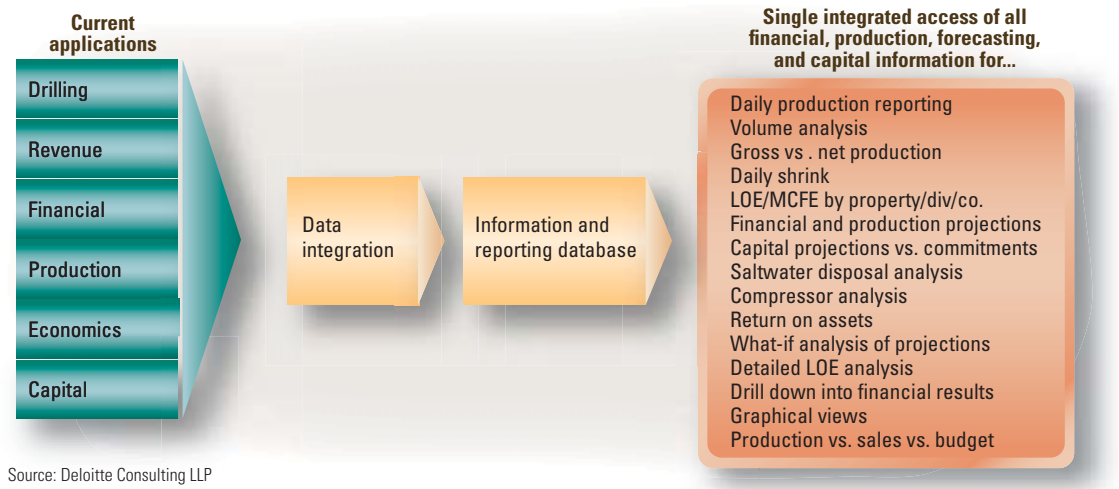
• **Organization.** The organizational aspect of performance management is the most critical and can easily be translated to mean that there is accountability at the individual and team level for results. This sounds good, but how can the people in the organization be held accountable for metrics they (1) agree with, (2) understand, (3) allow for business variability, and (4) tie to the corporate goals?

Most organizations give their people certain metrics, against which they are held accountable, and the defined metrics tie to the corporate goals in one form or another. But assigning metrics is the easy part. For example, a division manager is held accountable for a lease operating expense per unit of production or an engineer is held accountable for the accuracy of his drilling projects in terms of budget and timing. However, the challenge—and where most companies fail to see the light—comes in understanding, agreement, and business alignment.

For example, the data produced by the production and expense accounting systems for lease operating expense per metric cubic foot of production calculation does not tie to the spreadsheets the division managers or engineers have been using to run their individual parts of the business.

Furthermore, the metrics produced by the system do not allow the division manager or engineers to intuitively see the detailed data comprising the metric for understanding how they can impact what they are being evaluated on. Ultimately, the division managers and engineers virtually ignore the metrics and the people accountability program

CONCEPTUAL INFORMATION DELIVERY ARCHITECTURE



Source: Deloitte Consulting LLP

becomes a waste of time.

For a company to be successful in assigning, evaluating, and motivating based on metrics, it must give people in the organization access to information consistent across the company. Appropriate access to information allows people within the organization to agree upon the details backing up the metrics against which they are being measured. Additionally, this will allow the people to take action and control the factors driving the metrics.

For example, the division manager being measured on monthly lease operating expense should not only be charged with managing the expenses incurred but should also be able to tie the actual lease operating expenses incurred to the total operating metric calculation. Leading companies have eliminated corporate expense allocations that become diluted when general and administrative costs are spread across regions. Leading E&P companies have built models or reporting systems allowing their managers to see the high-level information they are accountable for and easily link to the detailed information. The managers can compare their goals to results and quickly drill into the detailed information that drives the results, allowing for the manager to take quick action. In other words, we are suggesting a single version of the truth to manage the business, where information is tied together for organization accountability.

- ***Process.*** Efficiently run organizations require some level of consistency of process across the organization. Many of today's larger E&P companies grew through acquisition. The acquired businesses have differing processes for estimating production volumes, developing financial budgets, capturing drilling and capital spend information, and viewing their financial statements.

For example, divisions may use different schedules for capturing daily production estimates from their field data capture systems (e.g., SCADA). Additionally, the acquired company typically defines and uses certain key data elements differently than the legacy divisions in the company. If the timing and data definitions among operating divisions differ, a challenge is created for the organization as a whole to capture information on a timely basis to meet all divisions' needs. Therefore, the divisions and corporate office start to rely on spreadsheets to manage the business and do not trust their production systems for reliable data.

To resolve the consistency issues, companies need to look at their processes that impact information and develop consistent policies and procedures across the organization for information capture, whether it means timing consistency, data definition standards, or the like.

Developing consistent processes is not an easy task and requires significant resource commitment across the organization. In the companies Deloitte has worked with, the operating groups and production accountants have worked collaboratively to develop and agree upon consistent processes across the organization. The process improvement efforts also require the company to take a deep dive into how they plan, budget, and forecast to develop consistent, forward-looking approaches. The company must align its planning, budgeting, and forecasting processes among the individual groups within the company, so, for example, the economic and reserve forecasts tie to the detailed operating assumptions generated by the lease operating budgets and production forecasts.

Commitment and leadership is the key for successful and sustainable process change. The operating groups must be committed to changing the process and should understand how process change benefits the company overall. Leadership should be ready to eliminate rogue activities and align processes with the corporate standards.

- ***Data.*** When managing performance, companies rely on their core systems to provide the data used to manage performance. The systems typically include revenue and production accounting, field data capture, marketing, economics, and drilling-management systems. However, many companies have baseline data issues within their current systems. Does this mean that the systems need to be replaced

with an integrated Tier-1 "ERP" like SAP? Not necessarily.

The issues boil down to a misuse of the existing systems and lack of training. Examples of real issues include: differing property hierarchies between systems, misuse of freeform or predefined data fields, missing data, and inaccurate meter grids. As a result, virtually all organizations turn to spreadsheets to manually manipulate data for performance and management reporting. Spreadsheets are prone to errors—studies have found that 90% of spreadsheets with more than 150 lines contain errors. It is doubtful any company wants to manage their business on information with such an error rate.

Although many of the information issues stem from process issues, the information issues first require data cleanup, followed by ongoing process improvement. The data issues are at the crux of why external spreadsheets are used for daily production reports, capital tracking summaries, and financial statements. Addressing the data issues requires a focused data cleanup effort, as well as cross-functional data definition teams to define how certain data elements will be used for reporting purposes. Addressing the data issues requires cross-division commitment and buy-in just as the process changes do.

Another part of the process improvement effort is changing processes to avoid future data cleanup efforts. For example, when new wells are brought online, a process for synchronizing the update of accounting, economic, and production well information needs to be defined. Improving the process not only improves the time in which data and information is obtained, but also increases the accuracy and value of the data created.

- **Delivery.** Unfortunately, most organizations are quick to jump first to the delivery or software solution (e.g., business intelligence, data warehouse, etc.). Invariably, taking this route results in failure because the projects never seem to end. Key information is not captured or reported, and executives get frustrated because they've spent millions of dollars on a "whiz-bang" tool but are not getting any more information than they had before the tool was implemented.

The delivery or software solution needs to be assessed along with the process, organization, and information dimensions. Implementing the delivery or software mechanism alone will result in a software tool nobody uses. The delivery mechanism needs to answer the following questions: What technologies are we going to use to deliver information to the divisions, corporate, and field organizations? How is the new software environment going to be integrated into the flexibility they have come to expect with the current spreadsheet environment? How is the planning process going to be integrated into the delivery mechanism?

Many companies struggle with information delivery solutions and develop individual information delivery silos. For example, the production divisions use one software database and application to report and deliver production information, while the accounting division uses another database and application to report financial information and another department uses a separate database for reporting capital project data. Consequently, the organizations cannot easily attain an integrated view of their organization.

Implementing an integrated information delivery mechanism in the most efficient and effective manner requires the organization to develop a data environment to integrate capital, production, financial, and budgeting data into a single view of the business. The conceptual information delivery architecture in the figure depicts a high-level view of how the information delivery mechanism relates to the current application and examples of what information might be generated. In an integrated information delivery environment, the company can view the latest daily production trends integrated with production revenues, lease operating expense components, and capital spending together. The integrated information delivery environment would allow the company to obtain a single view into the performance of the organization as a whole and how its individual parts drive performance results.

Conclusion

Improving an E&P firm's ability to access information requires a focus on process, organization, data, and delivery. Processes must be aligned across the company to ensure information is consistent and reliable.

Managers and personnel within the organization must understand and buy into the way information is being captured, disseminated, and analyzed, along with understanding how rewards are aligned with the information.

Data captured in the systems must be captured on a consistent basis to ensure that the information is accurate and reliable. The technology used for disseminating information must be designed to support the timely delivery of information across the organization.

Providing consistent, relevant, accurate, and timely information will improve an upstream company's ability to have more effective performance management processes, improve internal communication, and improve the ability to forecast results to the external stakeholders. ✦

The author

William F. Aimone III is a principal in Deloitte Consulting LLP's strategy & operations practice with a specialization in the oil and gas industry. His focus is to help clients design and implement financial and information strategies to support business and operational improvement. He has more than 17 years of consulting and industry experience in finance transformation and operations, strategic planning, performance management, business intelligence, and financial systems. Aimone holds a BS in Economics from Texas A&M University in College Station, Tex., and an MBA from Baylor University in Waco, Tex.

Bush: More US E&P vital in alternative fuel transition

Nick Snow
Washington Correspondent

Falling gasoline prices must not dissuade Americans from developing alternative fuels or finding more domestic oil and gas, US President George W. Bush said on Oct. 12.

Addressing a renewable energy conference cosponsored by the US Departments of Agriculture and Energy in St. Louis, Bush reiterated earlier statements that the US should move away from petroleum for its motor fuels to protect its economy, national security, and environment.

"As you can tell, I'm excited about new technologies. But I think we've got to be realistic about the timing. And in order to become less dependent on foreign sources of oil, we've got to explore for oil and gas in our own hemisphere in environmentally friendly ways. And one of the interesting technological developments is the capacity to find oil in unique places," he said.

Referring to the recent Jack 2 discovery made by Chevron Corp. and its partners in the deepwater Gulf of Mexico, Bush said it was accomplished with new technologies, "which enable us to go to new places, and they enable us to be wise stewards of the environment."

Bush said, "I understand there's a big debate about whether or not you can explore for oil and gas and protect the environment. I believe you can. And I understand that as we transition to the ethanol era...or the hydrogen area, we must also find oil and gas in our own hemisphere if the objective is to become less dependent on foreign oil."

Bush said the 2005 Energy Policy Act was a good beginning but added that the House and Senate now need to resolve differences in their competing federal offshore leasing bills.

States should share

Bush said the House and Senate need to come together between their respective leasing bills to encourage exploration in new areas of the gulf. "And I believe that states ought to share in the royalties because I know, in the state of Louisiana, for example, they have committed their share of new royalties in this new exploration to help protect their coastline," he said.

"And I believe Congress needs to get the bill to my desk as quick as possible. So when you finish the elections, get back and let me sign this bill so the American people know that we're serious about getting off foreign oil," Bush continued.

He said expanding domestic offshore exploration and production is vital because of growing US natural gas demand, not only for home heating and industrial fuels but also to generate electricity. He also said more LNG terminals need to be developed and approved so the US can begin to use gas from overseas.

"An increased supply of natural gas...makes it more likely that you're going to have rational bills, more likely the economy will continue to grow. And natural gas protects the environment," Bush said.

Developing new coal and nuclear technologies alongside hydrogen and ethanol alternatives are part of "a comprehensive approach to solving a national issue, which is dependence on oil, and how best to protect this environment," Bush said. "It's time to get rid of the old, stale debates on the environment and recognize new technologies are going to enable us to achieve a lot of objectives at the same time."

At the conference, Sec. of Agriculture Mike Johanns and Sec. of Energy Samuel W. Bodman jointly announced $17.5 million in federal grants for 17 biomass research, development, and demonstration projects. "This funding will spur new scientific innovation that will help us kick our overreliance on oil," Bodman said. ✦

API: US refiners spent $8 billion to provide ULSD

Nick Snow
Washington Correspondent

US refiners spent $8 billion, and pipelines and terminal operators spent hundreds of millions more to bring ultralow-sulfur diesel (ULSD) to market, an official of the American Petroleum Institute said at the group's annual meeting in Washington, DC.

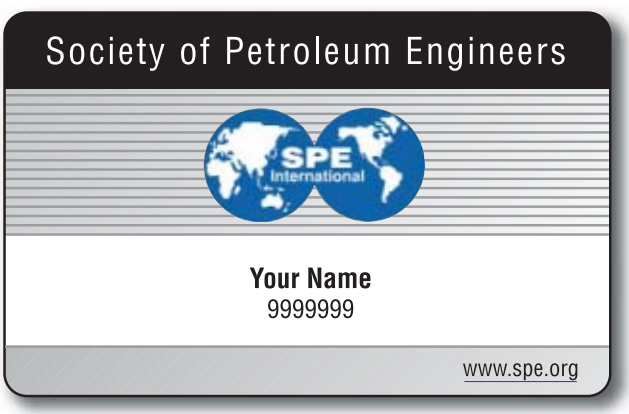
As of Oct. 15, the sulfur content of 80% of highway diesel sold in the US could not exceed 15 ppm, compared with 500 ppm previously. All but the smallest refiners had to start making ULSD in June. Some of them are processing to well below the specified level to offset contamination by residual sulfur in distribution systems.

Alfonse Mannato, fuels issues manager in API's downstream department, reported the spending estimates and said, "We were nervous about the rollout of this program. It's going smoothly. We haven't seen problems in supplies or vehicle performance."

He and John Felmy, API chief economist, said availability of the new product exceeds 80% of highway diesel.

"We're not out of the woods yet. But we haven't heard of any major problems," Felmy said.

Survival necessity.



Career necessity.

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At API's meeting, US Environmental Protection Agency Administrator Stephen L. Johnson called the transition to ULSD "the single biggest achievement since the removal of lead from gasoline 25 years ago."

California's deadline for availability of ULSD was Sept. 1, but EPA gave the industry outside that state an extra 45 days to address contamination and other potential transportation problems.

Tackling contamination

Mannato pointed out that some refiners are producing diesel with 7-8 ppm sulfur "so it will be at the specified level by the time it travels through two or three pipelines."

EPA set the availability deadline for the new fuel to accommodate exhaust-treatment systems on diesel engines starting with the 2007 model year.

"Right now, our diesel fuel is the cleanest in the world. Europe has a 10 ppm diesel, but it's not across the board. Much of what is sold there is still 50 ppm," Mannato said.

Current diesel engines will run cleaner on ULSD, but the emissions reduction won't be as dramatic as when the highway diesel transportation fleet fully turns over in 25-30 years, he said.

This will provide time for the oil and transportation industries to solve any operational problems, Mannato continued. Inadvertently mixing ULSD with low-sulfur diesel in vehicles' fuel tanks could clog fuel filters, so truckers and other operators have been alerted to report problems, he said. Additives at terminals will compensate for lubricity losses caused by sulfur removal.

Mannato said the transition to ULSD may have been more dramatic than the move to unleaded gasoline because the latter was accomplished over several years; ULSD came to the market within a few months.

Felmy said, "I was a little concerned in late May when the production figures for ULSD had not grown very much. Then they started to climb during June, and I felt better." ✦

DOE hopes for cellulosic ethanol plant by 2012

Angel White
Associate Editor

The US Department of Energy is evaluating bids for the first commercial cellulosic ethanol production facility in the US, with hopes that the plant will be in operation in 2012.

This announcement was made Sept. 23 by Alexander Karsner, DOE's assistant secretary for renewable energy, at a conference at Rice University in Houston. Also attending the conference, Biomass to Chemicals and Fuels: Science, Technology, and Public Policy, was Adam Schubert, US product strategy manager for BP PLC subsidiary BP Fuels Management Group, who said BP is collaborating with chemical company DuPont to produce biobutanol.

Along with DOE's bid program, the agency also is offering loan guarantees to encourage the effort toward achieving early commercial use of cellulosic ethanol. Title XVII of the 2005 Energy Policy Act provides the basis of DOE's loan guarantee program. Karsner said, "Companies must prequalify for this program by mid-2007."

Cellulosic ethanol—produced from nonfood plant material—is not yet commercial due to its production costs, which currently are higher than those of ethanol production from grain.

DOE hopes to drive down the cost of cellulosic ethanol production in the next 6 years to $1.07/gal from $2.25/gal in 2005, Karsner said. "We cannot achieve sustainability until we address profitability," he said.

Karsner said he views the energy solution as a "three-legged stool," with the three legs being research and development, policy, and markets. All three areas, he said, must work together for the solution to stand.

DOE has a goal for the US to produce enough ethanol by 2030 to equal 30% of current transportation fuel demand, he said.

During the week ended Sept. 8, US motor gasoline demand was 10.1 million b/d (OGJ, Sept. 18, 2006, p. 6). US ethanol production at midyear 2006 reached 318,000 b/d, according to the Renewable Fuels Association. Also at midyear, demand for ethanol reached 395,000 b/d, RFA said.

BP, DuPont collaboration

Schubert said BP is working with DuPont to introduce biobutanol into the energy market. Biobutanol is an advanced biofuel produced from the same agricultural feedstocks as ethanol.

Schubert outlined some of the benefits of the biofuel:

- It can be blended with gasoline at the refinery due to its low vapor pressure.
- It can use existing fuel infrastructure without the need for major modifications.
- It has the potential to be used at higher blend concentrations than ethanol in unmodified vehicles.
- It is less susceptible to separation in water than ethanol-gasoline blends.

According to a BP statement, BP and Dupont are assessing biobutanol's greenhouse gas emissions performance. "Initial indications are that, on the same feedstock basis, biobutanol delivers emissions reductions that are at least as good as ethanol," it said.

BP reported plans to introduce biobutanol as a gasoline biocomponent in the UK in 2007. That report stated that the company is working with Associated British Foods PLC subsidiary British Sugar to convert the country's first ethanol fermentation facility to produce biobuthanol. ✦

Brazil to produce H-Bio, reduce diesel imports

Peter Howard Wertheim
OGJ Correspondent

Brazil's state-owned Petroleo Brasileiro SA (Petrobras) plans next December to reduce diesel imports with the industrial scale production of H-Bio, a new form of biodiesel. H-Bio is obtained through the mixture of 10% vegetable oil with petroleum.

In 2007 Petrobras plans to use 256,000 l. of soy oil in the production of 2.56 million cu m of H-Bio fuel, Petrobras downstream director Paulo Roberto Costa said. That will replace 15% of Petrobras's current diesel imports, estimated at 1.7 billion l. in 2006.

By 2008, diesel imports will be reduced by 25% when H-Bio production will increase to 4.25 million cu m with a demand of 425,000 l. of soy oil, Costa said.

Petrobras should see a short-term savings of $145 million/year and a medium-term savings of $240 million/year, Costa said.

H-Bio was developed in Petrobras's research and development center (Cenpes) by a team headed by engineer Jefferson Roberto Gomes. The product, produced through a process called hydrogenation, is less polluting and more efficient than the traditional diesel, with lower sulfur and improved ignition quality.

H-Bio differs from biodiesel, which is also produced with vegetable oils but is blended into regular diesel by oil products distributors, not at the refinery level. Biodiesel is entirely vegetable-based. By 2008, it will be mixed with regular diesel at a rate of 2% but this date may be moved up to the first half of 2007, the government says.

By yearend, H-Bio will be produced at the Gabriel Passos (Regap) refinery, Minas Gerais state and, in 2007, at Presidente Getúlio Vargas (Repar) refinery, Paraná state and Alberto Pasqualini (Refap), Rio Grande do Sul state.

Petrobras invested $38 million in the three refineries to produce and stock H-Bio and will set up tenders for purchasing soy oil by November.

Brazil already produces 5.6 million cu m/year of soy oil, and this is currently the product with greatest availability for usage in H-Bio production. However, oil from other oleaginous plants, such as castor seeds, sunflower seeds, oil palm, and cotton, may also be used. ✦

France's flex-fuels program gets 'cautious approval'

Doris Leblond
OGJ Correspondent

France's oil industry has greeted the launch of the "Flex-fuel 2010" development program with cautious approval for the initial stages of the program, which Finance and Economy Minister Thierry Breton outlined in late September. However, a number of points in the program remain unclear.

In particular, the government has asked various stakeholders to sign the "Charter for Ethanol E85," although it has yet to be clarified over the next few weeks. The stakeholders include the oil industry, the motor fuels distributors, automobile manufacturers, the agriculture and agro industry sectors, and the administration.

Total SA, Esso SAF, Royal Dutch Shell PLC, and BP PLC executives all told OGJ that signing the charter would depend on its contents. They each will decide individually and not within the framework of the oil trade group Union Française des Industries Pétrolières (UFIP).

Ethanol E85

The bioethanol "Flex-fuel Ethanol E85" program was launched on the back of a feasibility study Breton commissioned in early June from Formula One racing champion Alain Prost. Described by Breton as the first "post-oil fuel," E85 contains 85% ethanol and 15% traditional gasoline. The project to introduce it as an alternative to unleaded gasoline in all of France's service stations by 2010 is deemed technically feasible, with the US, Brazil, and Sweden given as examples.

However, the study indicated that in France the project would only take off if "all concerned players launch the dynamics together" and if sufficiently attractive tax breaks make both the fuel and newly adapted vehicles competitive.

These vehicles cost slightly more than those using conventional fuels, and UFIP Delegate General Jean-Louis Schilansky pointed out to OGJ that E-85 has 30% less energy yield than gasoline, so it must be sold at a price at least 30% cheaper.

Prost said that automobile manufacturers indicated they could offer Flex-fuel vehicles as early as 2007 at a competitive price. He also said motor oil distributors have promised to install at least 500 "green pumps" by yearend 2007 in a number of service stations.

Schilansky confirmed that installa-

tion of the E85 pumps within that time is possible, but they would have to be set up at the largest service stations first because installation costs per station would be €20,000-40,000.

Commenting on Breton's announcement that government tax breaks would bring down the cost of E85 to 80¢ (Euro)—far lower than the current unleaded—Schilansky said that if this were really the case, it could very quickly become the anticipated alternative, providing the tax breaks would be perennial.

Regarding the problem of the refining industry's producing too much gasoline, "we will produce the same amount but export more of it," Schilansky said.

E85 vs. diesel

Substituting E85 for diesel, on which half the vehicles in France are now running, would be more difficult, he says. Diesel oil is cheaper in France because of lower taxation. Nonetheless, if oil prices shoot up, it could happen that E85 might prove competitive with diesel oil in time. In any case, the tax breaks cannot be squeezed below the lowest level allowed by the European directives.

Schilansky did not think E85 was likely to be developed in the rest of the EU. "France is the largest agricultural country in Europe and the second worldwide after the US, he pointed out. "She has the acreage to produce the crops to meet the needed ethanol demand beyond 2010." France also has a number of ethanol production plants either already on stream or about to be built, he added.

Breton pointed out other advantages: the ethanol line would give a needed boost to France's farmers—an argument also advanced by Agriculture Minister Dominique Bussereau—biofuels development would benefit the environment by "strongly" reducing carbon dioxide emissions from transport, and E85 would reduce France's oil imports, improving the "global balance with oil-producing countries." ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Japan employs energy choice

Even in a world where energy sources are tight, there is still enough oil and gas in the ground to guarantee choices. Consider the efforts of resource-poor Japan to secure itself a stable energy supply.

To win support for its nuclear ambitions, Iran has threatened Japan with the oil weapon on a number of occasions, perhaps most obviously by threatening—and eventually reducing—its 75% stake in development of giant Azadegan oil field.

No less worrying for Japan, the Russian government has halted the Sakhalin-2 project, claiming that the companies involved—Royal Dutch Shell along with Japanese partners Mitsui and Mitsubishi—have ignored environmental regulations and caused $10-50 billion in damage.

The market prevails

But the market appears to have prevailed as Japan has turned to Indonesia and Australia to fill a substantial portion of its future energy needs.

Indeed, Japan's Inpex Holdings Inc., which had the Azadegan stake, now plans to invest about ¥500 billion ($4.22 billion) to launch natural gas production in Indonesia by 2015. The Japanese energy developer, which has a 100% stake in the project, aims to ship 3-5 million tonnes/year of LNG to Japan and elsewhere.

Inpex has a similar project under way in an Australian field, where it holds a 76% stake. There the firm is spending ¥700 billion, with plans to produce 6 million tonnes/year of LNG starting in 2012.

In fact, these two fields alone could jointly supply 15-20% of Japan's LNG needs. In terms of percentage of energy needs, that 15-20% represents more than Japan imports from Iran now.

Inpex reportedly has found a gas deposit capable of supporting 3 million tonnes/year of LNG in Indonesia, where it will start drilling at four locations beginning early next year to confirm the reserves.

The next step will be to submit a production plan to the Indonesian government in 2008 for approval. According to one observer, negotiations with the Indonesian government hold the key to realizing gas production there. But unlike with Iran or Russia, the risk of falling victim to resource nationalism is low in the Indonesian project.

Conversion plans

Inpex is said to be developing plans to construct a facility near the city of Darwin in northern Australia for liquefying the Indonesian gas. The LNG will be shipped to markets in Japan and elsewhere. Undersea pipelines will transport the gas from Indonesia to Darwin.

Last August, Kon Vatskalis, minister for mines and energy in Australia's Northern Territory, said Inpex is likely to reach an accord with Indonesia and Australia for processing gas from its Abadi field in Darwin.

At the time, Vatskalis said ConocoPhillips may already be designing an expansion of its 3.24 million tonne/year Darwin LNG plant, which currently liquefies gas from Bayu-Undan field in the Timor Sea.

One way or another, it's a world of choice. ✦

London inauguration marks Langeled start-up

Uchenna Izundu
International Editor

The Langeled pipeline consortium and the British and Norwegian prime ministers on Oct. 16 inaugurated the 600-km southern leg of 1,200-km Langeled pipeline, which has begun exporting gas from the Sleipner hub in the Norwegian North Sea to Easington on the UK's east coast (OGJ, Oct. 9, 2006, Newsletter).

Statoil ASA designed and laid the 44-in. diameter southern segment on behalf of Norsk Hydro ASA, operator of the Langeled development phase, which was completed 3 billion kroner ($444.1 million) below budget. Anne Lycke, Hydro's Langeled asset manager, told OGJ that the company secured steel supply contracts before steel prices jumped.

When complete, the Langeled pipeline will carry gas from Nyhamna on Norway's west coast through the Sleipner riser platform and on to Easington, becoming the world's longest subsea export pipeline. Nyhamna is the site of separation and treatment facilities for production from Ormen Lange gas-condensate field in the Norwegian Sea.

Flow from Nyhamna to Sleipner through Langeled's 42-in. diameter northern section is to begin when Ormen Lange starts production next October. Construction is about 90% complete, according to Hydro. Remaining work includes completion of the Nyhamna gas processing plant; drilling and completion of the first production wells; testing of the subsea installations; installation of the last umbilical between Nyhamna and Ormen Lange field; and midline tie-in on Langeled.

When Ormen Lange is on stream, Langeled will deliver 70 million cu m/day of gas to the UK. The Ormen Lange reservoir, about 3,000 m below the seabottom in 800-1,100 m of water, will produce from 24 subsea wells drilled through four seabed templates.

Hydro said a challenge has been the uneven seabed, with peaks 30-60 m high, over Ormen Lange.

"The first two remotely controlled subsea production stations are located 120 km from shore at a water depth of 850 m, making Ormen Lange one of the world's largest and most advanced subsea-to-shore developments," Hydro said.

Eivind Reiten, president and chief executive officer of Hydro, pointed out that the Ormen Lange seabed templates will operate for 30 years without maintenance.

He said Hydro and its partners have had to solve flow-assurance problems and custom-build compressors able to maintain gas flow over the system's great distance. They also custom-built an excavator to smooth the seabed over the field and trench along a 35° incline on the Storegga subsea landslide for the two, 30-in. multiphase pipelines that will carry well streams ashore.

"We have made what seemed impossible 5 years ago possible," Reiten said.

Partners in the Langeled joint venture are Hydro, 17.61%; Petoro AS, 32.954%; Statoil, 14.985%; Dansk Olie & Naturgas (Dong), 10.222%; Esso Exploration & Production Norway AS, 6.947%; A/S Norske Shell, 16.503%; and ConocoPhillips, 0.779%. Gassco AS, which handles transportation of Norwegian gas to continental Europe and the UK, becomes operator as operations begin. ✦

Study sees uneven natural gas trade in Europe

The wholesale gas market in Europe is developing unevenly and too slowly to suit many traders.

Furthermore, the liberalization that stimulates gas trade remains subject to questions about whether it's effective and even appropriate, notes a new research study.

According to European Gas Trading 2006 by Mary Jackson and Nigel Harris, principal consultants and directors of Kingston Energy Consulting of London, the UK and Benelux countries—Belgium, the Netherlands, and Luxemburg—have Europe's only "truly liquid trading markets" for gas.

Although liquidity is limited elsewhere, "nascent trading markets" in France, Germany, Italy, and Spain are growing rapidly, the consultants say. The UK accounts for 74% of total European gas trading volumes, followed by the Netherlands, 13%; Belgium, 6%; Spain, 4%, and Italy, Germany, and France, 1% each. Among the higher-volume countries, market structures vary. The UK has over-the-counter spot and forward trading based on the virtual National Balancing Point, beach terminals, and the Interconnector pipeline between the UK and Belgium.

In Belgium, Zeebrugge is a major physical trading hub. The Interconnector links Zeebrugge prices with the UK market. The Title Transfer Facility in the Netherlands is the balancing market for the Dutch network and serves as a virtual trading point for the Dutch and German markets.

In Germany, problems of network access hamper trading. Italy, France, and Spain have small but growing markets based on virtual trading points, border-crossing locations, and LNG terminals.

Major gas producers and suppli-

ers—some of which are formerly state-owned national gas monopolies—remain the largest traders, Jackson and Harris observe. But use of the traded markets remains small in comparison with volumes bought and sold under long-term contracts.

The consultants note that the European Union has faulted members for slow progress in the liberalization of gas markets and that the European Commission is investigating energy companies for possible violations of competition rules. "It is evident that the implementation of competitive gas markets is deeply flawed in many EU member states, but the EC is clearly of the view that it is the implementation and not the model that is at fault," Jackson and Harris say. "There are market participants who would argue that liberalization is the only way forward and those who argue equally strongly that it is a road to disaster," they say. ✦

MMS: Gulf of Mexico finds extend Lower Tertiary Trend

Nick Snow
Washington Correspondent

Twelve ultradeepwater discoveries in the Gulf of Mexico extend the Lower Tertiary Trend and represent a resource that could produce oil and gas for decades to come, the US Minerals Management Service said on Oct. 10.

"This is an exciting new trend in the Gulf of Mexico, and the recent announcement by Chevron [Corp.] and its partners of the results of the Jack 2 well provides additional proof of its great potential," MMS Director Johnnie Burton said as the Department of the Interior agency released a summary of 12 announced discoveries in the area.

"This trend began to materialize in 2001 and 2002 with several discoveries in the Alaminos Canyon and Walker Ridge areas and now has extended to the Keathley Canyon area. The area could be as wide as 300 miles and involve as many as 3,000 blocks that MMS administers," she said.

While the Lower Tertiary Trend has been a significant petroleum resource in Texas and southwestern Louisiana for years, its reserves contribution in the gulf was negligible until the recent discoveries, MMS indicated. It said 99% of the gulf's proved reserves were found in sediments less than 23 million years of Miocene age (Upper Tertiary) and younger, while 1% are in older than 65 million years (Jurassic and Cretaceous age) sediment that primarily are in near-shore areas off Louisiana and Alabama.

The 12 recent discoveries were in Lower Tertiary formations deposited 23-64 million years ago in 15,000-30,000 ft of water, MMS said.

Officials also noted that the widespread industry interest in the Jack well test and the discovery by BP on its Kaskida prospect in 5,860 ft of water preceded heavy bidding activity at MMS's Western Gulf Sale 200 in August.

At that sale, they said, 82 tracts received bids in the Keathley Canyon area. BP offered the sale's highest bid of $21 million for Block 58 in Keathley Canyon, while Petrobras bid $12.8 million for Block 59, and Shell bid $6 million for Block 56 there. ✦

Argentina evokes law to force diesel imports

Peter Howard Wertheim
OGJ Correspondent

Argentina has threatened statutory sanctions against foreign oil companies if it detects problems in the supply of products such as diesel.

The administration of President Néstor Kirchner reactivated a law, enacted in 1974 during the administration of former nationalist-populist President Juan Perón, empowering the government to intervene in commerce and industry, close establishments, apply fines, and imprison executives.

The main diesel suppliers in Argentina are Petroleo Brasileiro SA (Petrobras), Royal Dutch Shell PLC, Repsol YPF, and a unit of ExxonMobil Corp.

In a press conference, Guillermo Moreno, domestic commerce secretary, said, "It is the duty of all public employees to enforce abidance of the law." He threatened to imprison executives from oil companies that do not increase diesel imports as specified by the government.

Diesel prices are frozen in Argentina at levels below international prices. The government insists that companies can compensate for losses on diesel imports with revenues from exports of other products.

Members of Moreno's staff have told the powerful farmers' organization Soc. Rural Argentina (SRA) that oil companies had failed to import diesel levels demanded by the government to alleviate a shortage plaguing agriculture.

Hundreds of SRA members recently blocked roads linking Rosário with Buenos Aires, Córdoba with Pilar, and Tucumán with Famaillá.

Kirchner seeks reelection in 2007 and is trying to avoid inflation, which hobbled Argentina during the 1990s.

In September, Argentina's Internal Commerce Secretariat told the local Shell unit to stop selling a new diesel formulation, which costs 10% more than regular diesel, because the company failed to obtain government approval. Last year, Kirchner called on citizens to boycott Shell after the local unit raised pump prices amid rising world oil prices. Shell dropped prices after government-aligned protest groups marched on Shell stations. ✦

Mauritania turning to gas as discoveries multiply

Mauritania's Atlantic coastal basin may be destined to become a source of liquefied natural gas.

At least one of the participants in the deepwater exploration play that takes in the country's entire 335-mile coastline has stated that a minimum of 4 tcf of recoverable gas is needed to support a commercial LNG project.

Gaz de France's late 2005 agreement with Dana Petroleum PLC, London, finalized in recent weeks, gave Gaz de rance interests in lightly drilled blocks 1, 7, and 8 off Mauritania, at least one of which contains a major gas discovery, Pelican on Block 7.

At least four of the discovered oil fields, Chinguetti, Tevet, Tiof, and Banda, operated by other companies contain varying volumes of gas (see table).

In mid-2006, Gaz de France said it was starting a feasibility study of an LNG project in Mauritania based on deepwater gas discoveries (OGJ Online, July 14, 2006). Because of the barely explored nature of the country's offshore, it is unclear what is the total volume of recoverable gas identified so far. The development time frame is also hazy but appears to be no earlier than 2012-14.

Meanwhile, the several operators exploring the area's nine blocks plan to continue wildcatting the area and appraising the discoveries made so far. Dana Petroleum operates blocks 1, 7, and 8; Woodside Petroleum Ltd., Perth, operates blocks 2 to 6 and has an interest in Block 7; and Al Thani Corp. of Sudan operates Block 19.

The nine blocks total more than 14.5 million acres.

For one thing, the Gaz de France agreement calls for the French company to carry Dana Petroleum's interest in the current three-well program, one well on each of the blocks in which Gaz de France acquired interests, up to a maximum of $30 million.

Besides Gaz de France, the major gas players BG PLC, Malaysia's Petronas, and Wintershall AG also hold interests off Mauritania.

Chinguetti area gas

Woodside-operated Chinguetti field, the only discovery on production off Mauritania, went on production in February 2006 at 70,000 b/d and was averaging 30,000 b/d in October, said participant Roc Oil Co. Ltd., Sydney.

Because of the lagging production rate, the 123 million bbl reserve estimate is under review and a time-lapse (4D) seismic survey has been proposed for 2007.

In 2,625 ft of water 50 miles off Nouakchott, the field is producing into a floating production, storage, and offloading vessel and was originally given a 10-year life. Capacity of the Chinguetti gas handling/reinjection facilities is 80 MMcfd.

Tiof, 25 km north of Chinguetti, at 60 sq km is about five times Chinguetti field's areal extent. One Tiof well cut a 49.5-m gas column overlying a 38.5-

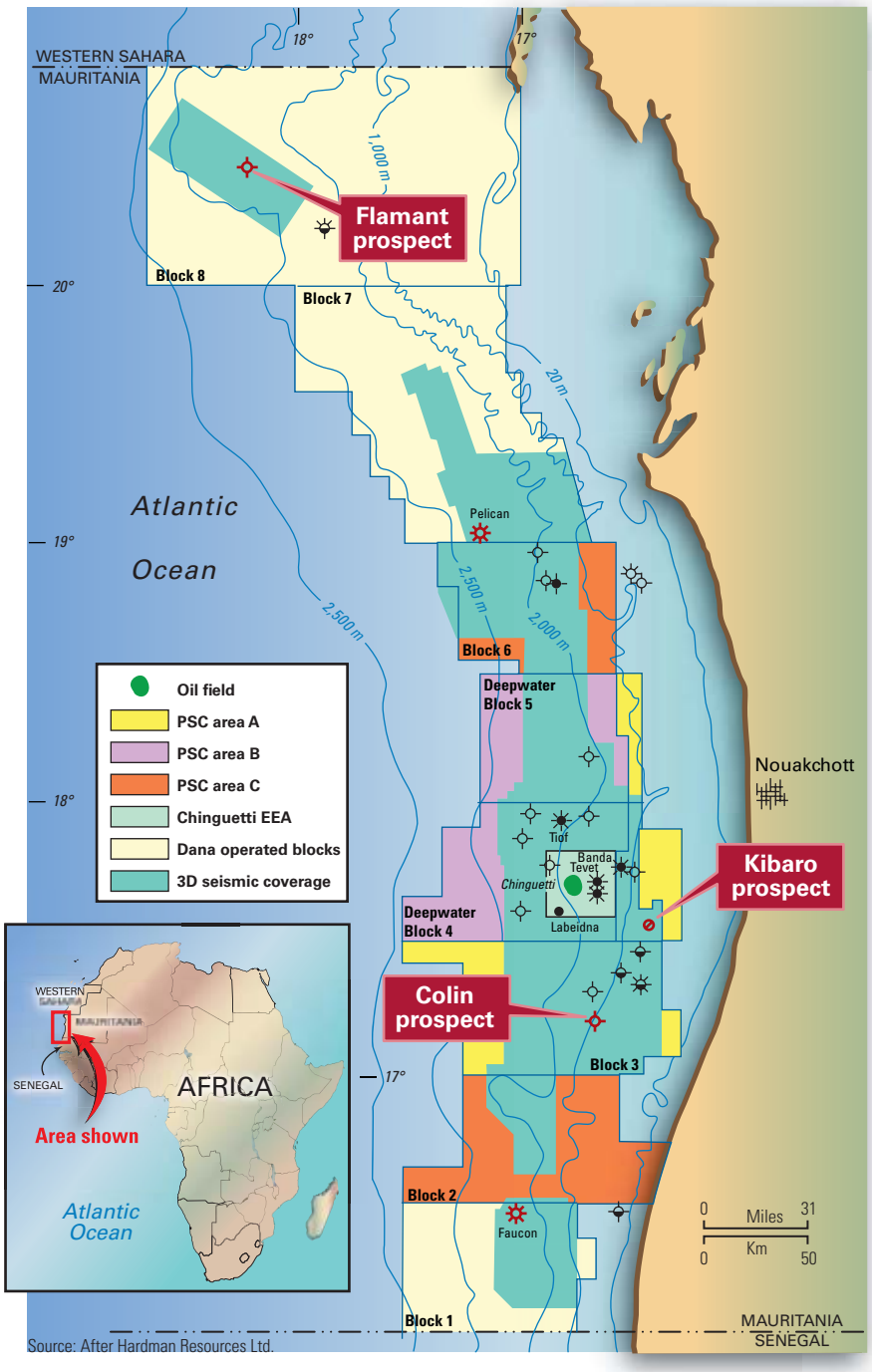
THE DISCOVERED RESOURCE BASE OFF MAURITANIA

Field/ discovery name	Block	Discovery year	Water depth, ft	Remarks
Chinguetti field	4	2001, oil	2,624	2P reserves 123 million bbl; started production Feb. 25, 2006
Tiof field	4	2003, oil	3,540	Potential phased development; contingent resource volume 287 million bbl
Banda discovery	4	2002, gas oil leg	1,000	110 m gas/24 m oil column; contingent 1.2 tcf gas recoverable. Mean oil 344 million bbl STOIIP
Tevet field (Mio.)	4	2004, oil	1,600	41 million bbl contingent resource pending concept selection
Tevet field (Cret.)	4	2005, oil	1,525	8 m gross oil-bearing sands
Pelican discovery (Cret.)	7	2003, gas	5,575	364 m gross gas column with numerous sands
Labeidna discovery	4	2005, oil	4,150	Thin sands over 116 m gross pay
Faucon discovery (Cret.)	1	2005, gas	3,800	10 m gas-bearing sands; 200 bcf gas in place (per operator)

Source: Modified from Hardman Resources Ltd.

DISCOVERIES AND BLOCKS OFF MAURITANIA

Fig. 1



Source: After Hardman Resources Ltd.

m oil column, and an appraisal well flowed at maximum rates of 12,400 b/d of oil and 11 MMscfd of gas.

Banda oil field, on Block 4 east of Chinguetti, is judged to contain at least 1.2 tcf of recoverable gas. Banda is primarily a gas discovery with a thin oil leg.

The 2004 Tevet well discovered a 44-m oil column below a minimum 68-m gas leg within tieback distance of Chinguetti.

Northern area

The largest single known nonassociated gas deposit is Pelican, which when discovered in 2003 was a 93-mile stepout from the oil discoveries in the Chinguetti area.

Also, Pelican's multiple Upper Cretaceous sands are geologically distinct from the Miocene-aged sandstone systems that hosted the Chinguetti, Tiof, Tevet, and Banda discoveries.

After the 2003 Pelican-1 gas discovery near the south line of Block 7, Dana Petroleum and others recorded 1,540 sq km of 3D seismic data between Pelican and shore where geochemical results indicated that oil may have been displaced to the east, said participant Hardman Resources Ltd., Perth. Tullow Oil PLC, London, is acquiring Hardman Resources (OGJ Online, Sept. 26, 2006).

Dana Petroleum plugged the Flamant-1 wildcat on western Block 8 in September 2006 but expressed encouragement after the well penetrated 1,150 m in the carbonate primary target, topped at 6,924 ft. It said the shallower part of the well had gas-bearing intervals, indicating mature hydrocarbon source rock in the area. TD is 10,742 ft.

The Flamant drillsite is 120 miles northwest of the Pelican discovery and about 50 km south of the border with Western Sahara. Block 8 covers 11,797 sq km. Before drilling, Dana Petroleum had estimated the Flamant structure size at more than 6 tcf of gas.

Dana Petroleum spudded Aigrette-1 on Oct. 7, 2006, in 4,526 ft of water on a Cretaceous gas prospect on Block 7 about 27 miles northwest of and on trend with Pelican. It is projected to 16,154 ft.

Southern area

A gas discovery in Cretaceous at the first modern well drilled on Block 1 has implications for exploration to the south off Senegal.

Dana Petroleum drilled Faucon-1 to TD 12,054 ft in late 2005. The well found 46 ft of net hydrocarbon bearing Cretaceous sandstone in two intervals above a further 270 ft of potential sandstone reservoir.

The well tested a Lower Campanian

channel system with updip pinchout against a salt diapir.

The 200 to 400 bcf the company surmised to be in place is not enough for stand-alone development but proves a working petroleum system. Faucon's Cretaceous sands also demonstrated that sufficient potential reservoir sand can be present to accommodate much larger discoveries, Dana Petroleum said.

The findings provided encouragement for other prospects identified on Block 1, including Petrel.

It also proved encouraging for the St. Louis exploration license off northernmost Senegal.

Tullow Oil PLC's Energy Africa Ltd. unit acquired the St. Louis license with Senegal's state Petrosen in late 2003. Tullow operates St. Louis with 60%, having farmed out 30% to Dana in late 2004. Petrosen holds 10%.

Tullow acquired a 1,200-km 2D seismic survey in 2004 and identified several prospects.

The Faucon-1 well results led to a conclusion that it will be beneficial to gather 3D seismic data on St. Louis before drilling an exploration well off Senegal. This survey could start in late 2006 and could be combined with an incremental survey in the southern part of Block 1.

The 2006 drilling program off Mauritania began with Colin-1 on Block 3, which found prime quality Miocene reservoir B sands but no commercial hydrocarbons. Hardman Resources said the sand quality was much better than at Chinguetti, where the B sands are known to be gas-bearing.

After drilling Flamant and Aigrette, the rig is to return to Block 4 to drill Kibaro-1. Then it will head for infill drilling at Chinguetti field, after which it will depart Mauritania and return in mid-2007. ✦

Northern Somalia exploration effort planned

Canmex Minerals Corp., Vancouver, BC, signed a nonbinding agreement to take a farmout from Range Resources Ltd., Perth, on two blocks in the nonproducing Nogal and Al Medo/Darin basins onshore between the Gulf of Aden and Indian Ocean in northern Somalia.

Completion is expected by yearend.

The basins lie across the Gulf of Aden from Yemen, which had a 23% success rate and average discovery size of 96 million boe recoverable in 1994-2006, Range noted. The Somali record is 11 oil and gas discoveries, none producing, out of 60 wildcats drilled in 580,000 sq km of sedimentary basins.

The basins with the acreage covered under the agreement are identical to Yemen's productive basins, Range said.

The agreement calls for Canmex to become operator and spend $50 million to earn an 80% interest in the two blocks in Puntland State. The minimum work program is two exploration wells in each basin.

Of the 80% interest, one-fourth in one or both basins is available to third parties on terms agreeable with Range and Canmex.

The companies have received expressions of support from the Puntland and Transitional Federal Government of Somalia. ✦

Cambodia

Cambodia's National Petroleum Authority awarded Block E in the Khmer basin to Medco International Petroleum Ltd. and JHL Petroleum Ltd.

The block covers 5,000 sq km in the Gulf of Thailand just off the country's northwest coast. Medco will operate the block with 90% interest, and JHL has 10%.

China

Primeline Energy Holdings Inc., London, completed a 549 sq km 3D seismic survey over the Lishui 36-1 discovery and adjacent areas of Block 25/34 in the East China Sea.

Interpretation is to start in late November 2006, and data will be used to pick future drilling locations on the 7,006 sq km block. Block interests are Primeline 75% and China National Offshore Oil Corp. 25%.

Arizona

High Plains Petroleum Corp., Boulder, Colo., staked a 4,300-ft wildcat in Apache County to test the Permian Supai, Pennsylvanian Naco, and Devonian Martin formations.

The LC State 12-1, in 12-14n-24e, is a follow-up well to a potash well that found oil and gas in four Upper Supai carbonates. The location is on a 12,800-acre anticline in the Holbrook basin.

United Drilling Co. Rig 11 is drilling the first well in a three-well program for oil, gas, and helium in the Holbrook basin with funding by Finley Resources Inc., private Fort Worth independent.

Washington

Two unidentified private companies completed taking a farmout on all lands in Whatcom County held by Rival Petroleum Co., a subsidiary of Blue Parrot Energy Inc., Calgary.

The farmees will earn 100% of Blue Parrott's working interest with the drilling of the first well, Blue Parrot said. Rival will retain a 7.5% nonconvertible gross overriding royalty interest plus the right to participate for 25% in the drilling of any wells and the acquisition of any areas of mutual interest.

Rival Petroleum has held interests for several years to an acreage block entirely in the US between Bellingham, Wash., and Abbotsford, BC, in the Bellingham basin. The area is thought prospective for shallow sandstone gas and coalbed methane.

New technique calculates borehole curvature, torsion

Xiushan Liu
Sinopec Corp.
Shandong, China

Wellbore curvature and torsion greatly influence the forces applied on the downhole pipe string and its consequent deformation. They serve as the bases for calculating the drag and torque of a pipe string and checking its strength and also serve as indices to evaluate the quality of a well trajectory. Accordingly, curvature and torsion affect well drilling and completion, production, and even workover operations.

It's necessary to accurately calculate and describe the shape of a wellbore trajectory in order to monitor and control it effectively. A wellbore trajectory is a continuous and smooth curve in space, which bends (builds or drops) and turns simultaneously.

The industry has recognized the importance of borehole curvature for more than 50 years and has widely applied the research results in the field. Engineers have done very little research, however, on borehole torsion.

This article models a moving frame on a wellbore trajectory, gives its equation and establishes contact with the wellbore trajectory, and presents a new method to describe the shape of wellbore trajectory in space.

From the point of view of kinematics, the article gives the law of frame's motion while moving along wellbore trajectory and the kinematic meanings of borehole curvature and torsion, thus revealing the intrinsic relationship and basic characteristic of various parameters of wellbore trajectories.

The method and equations discussed provide mathematically consistent techniques, not only for planned well paths, but also for survey calculations.

Inclination, azimuth

Originally, the oil and gas industry was focused on drilling vertical wells. The concept of inclination angle arose when engineers realized that a drilled trajectory is not a plumb line. Then the concept of azimuth angle came into being when they further understood that a drilled trajectory does not change in a vertical plane.

We can describe the change in direction of a well trajectory by means of inclination angle and azimuth angle, but the curvature is also significant, as it greatly affects well drilling, completion, and even production.

Over the past 50 years, the drilling industry has engaged in a lot of research related to the problem of borehole curvature.[1-11] In 1957, Lubinski published a now well-known formula to calculate dogleg angle and its nomogram.[1] In 1968, Wilson introduced the radius-of-curvature method and a formula to calculate the curvature of a drilled trajectory.[4]

The primary parameters related to wellbore trajectory curvature are bending angle (dogleg angle) and borehole curvature. In order to calculate and analyze them, researchers have provided analytic methods, diagram-searching methods, graphic methods, and the Ouija board method.

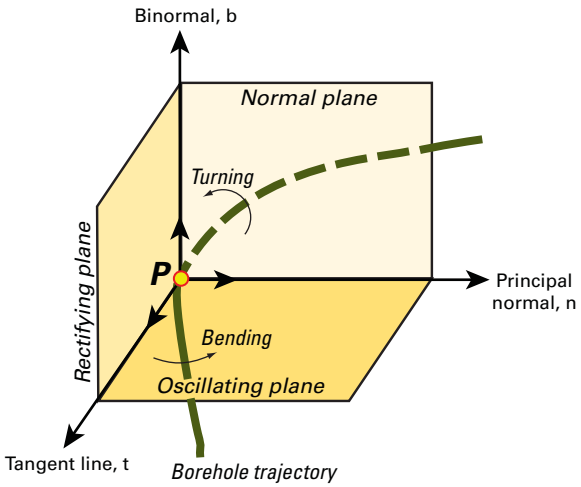
Although the last three methods show considerable error and are inconvenient to use, they were commonly used into the 1980s. Today, the analytic method is the most often used to calculate the bending angle and curvature of a well trajectory.

A wellbore trajectory is simply a curve in space, which bends and turns simultaneously to change direction. Research shows that the extensive turning of a well trajectory may twist a downhole pipe string, greatly increasing the forces applied to the string and causing deformation.[5]

In 1983, E.E.

Moving frame

Fig. 1



Fitchard and S.A. Fitchard introduced a formula to calculate borehole torsion applied to a cylindrical helix trajectory (OGJ, Jan. 17, 1983, pp. 121-124). In the following 10 years, there was little additional research on borehole torsion.

Since 1992, we have systematically studied the curvature and torsion of wellbore trajectories in space using differential geometry.[5 7-11] Through establishing a moving frame on wellbore trajectory and contacting it with the trajectory's equation, we introduce a new perspective and method to describe the shape of wellbore trajectory in space. From the perspective of differential geometry, this expands the definitions and geometric meanings of bending angle, borehole curvature, torsion angle, and borehole torsion.

This work verifies the research results provided by A. Lubinski and G.J. Wilson with regard to wellbore curvature, and presents general equations to determine torsion angle and borehole torsion.[5 7 10] It also includes concrete calculation formulae for various typical models of wellbore trajectory, revealing the intrinsic relationship and characteristics of the various parameters of wellbore trajectory.

With regard to survey calculations, this author and colleagues proposed the curve structure method based on the bending and turning parameters of wellbore trajectory[9 10] and researched the calculation method to determine the average borehole curvature over a survey interval.[11]

In addition, we investigated the law of frame's motion while moving along a wellbore trajectory from the point of view of kinematics and provide the kinematic meanings of borehole curvature and torsion.

Moving frame

As mentioned, a wellbore trajectory is a continuous and smooth curve in space, bending and turning simultaneously to change direction. There are some intrinsic relations between the parameters that serve as the basis of describing and calculating a well trajectory.

Equations

$$r = r(L) = Ni + Ej + Hk \tag{1}$$

$$\begin{cases} t = \dot{r} = \dfrac{dr}{dL} \\ n = \dfrac{\dot{t}}{|\dot{t}|} = \dfrac{\ddot{r}}{|\ddot{r}|} \\ b = t \times n \end{cases} \tag{2}$$

$$\begin{cases} \dfrac{dN}{dL} = \sin\alpha\cos\phi \\ \dfrac{dE}{dL} = \sin\alpha\sin\phi \\ \dfrac{dH}{dL} = \cos\alpha \end{cases} \tag{3}$$

$$\begin{cases} t = \sin\alpha\cos\phi i + \sin\alpha\sin\phi j + \cos\alpha k \\ n = (\lambda_\alpha\cos\alpha\cos\phi - \lambda_\phi\sin\alpha\sin\phi)i \\ \quad + (\lambda_\alpha\cos\alpha\sin\phi + \lambda_\phi\sin\alpha\cos\phi)j + (-\lambda_\alpha\sin\alpha)k \\ b = (-\lambda_\alpha\sin\phi - \lambda_\phi\sin\alpha\cos\alpha\cos\phi)i \\ \quad + (\lambda_\alpha\cos\phi - \lambda_\phi\sin\alpha\cos\alpha\sin\phi)j + (\lambda_\alpha\sin^2\alpha)k \end{cases} \tag{4}$$

Where:

$$\begin{cases} \lambda_\alpha = \dfrac{k_\alpha}{k} \\ \lambda_\phi = \dfrac{k_\phi}{k} \end{cases}$$

$$\begin{cases} \dot{t} = \dfrac{n}{R} \\ \dot{n} = -\dfrac{t}{R} + \dfrac{b}{\rho} \\ \dot{b} = -\dfrac{n}{\rho} \end{cases} \tag{5}$$

$$\begin{Bmatrix} \dot{t} \\ \dot{n} \\ \dot{b} \end{Bmatrix} = \begin{bmatrix} 0 & \frac{1}{R} & 0 \\ -\frac{1}{R} & 0 & \frac{1}{\rho} \\ 0 & -\frac{1}{\rho} & 0 \end{bmatrix} \begin{Bmatrix} t \\ n \\ b \end{Bmatrix} \tag{6}$$

$$\omega = \tau t + \kappa b \tag{7}$$

$$\begin{cases} \dfrac{dt}{dL} = \omega \times t \\ \dfrac{dn}{dL} = \omega \times n \\ \dfrac{db}{dL} = \omega \times b \end{cases} \tag{8}$$

$$\cos\varepsilon = \frac{t_1 \cdot t_2}{|t_1||t_2|} \tag{9}$$

$$\cos\varepsilon = \cos\alpha_1\cos\alpha_2 + \sin\alpha_1\sin\alpha_2\cos\Delta\phi \tag{10}$$

Where:

$$\Delta\phi = \phi_2 - \phi_1$$

$$\kappa = \left|\frac{dt}{dL}\right| = |\dot{t}| \tag{11}$$

$$\kappa = \lim_{\Delta L \to 0}\left|\frac{\varepsilon}{\Delta L}\right| \tag{12}$$

$$\kappa = \sqrt{\kappa_\alpha^2 + \kappa_\phi^2\sin^2\alpha} \tag{13}$$

$$\bar{\kappa} = \sqrt{\left(\frac{\Delta\alpha}{\Delta L}\right)^2 + \left(\frac{\Delta\phi}{\Delta L}\right)^2\sin^2\bar{\alpha}} \tag{14}$$

Where:

$$\Delta L = L_2 - L_1$$
$$\Delta\alpha = \alpha_2 - \alpha_1$$

$$\bar{\kappa} = \frac{\varepsilon}{\Delta L} \tag{15}$$

$$\cos\theta = \frac{b_1 \cdot b_2}{|b_1||b_2|} \tag{16}$$

$$\cos\theta = a\cos\Delta\phi - b\sin\Delta\phi + c \tag{17}$$

Where:

$$a = \lambda_{\alpha 1}\lambda_{\alpha 2} + \frac{1}{4}\lambda_{\phi 1}\lambda_{\phi 2}\sin 2\alpha_1\sin 2\alpha_2$$

$$b = \frac{1}{2}(\lambda_{\alpha 1}\lambda_{\phi 2}\sin 2\alpha_2 - \lambda_{\alpha 2}\lambda_{\phi 1}\sin 2\alpha_1)$$

$$c = \lambda_{\phi 1}\lambda_{\phi 2}\sin^2\alpha_1\sin^2\alpha_2$$

$$\tau = \begin{cases} +|\dot{b}|, \text{ if } \dot{b} \text{ and } n \text{ are in the opposite direction} \\ -|\dot{b}|, \text{ if } \dot{b} \text{ and } n \text{ are in the same direction} \end{cases} \tag{18}$$

Basic equation

Draw a tangent line across a given point P on a well trajectory and intercept a unit length on the tangent line as unit tangent vector **t**; it points in the onward direction of the well trajectory (Fig. 1). Next, draw a unit vector in the bending direction of the well trajectory as unit principal normal vector n; it points in the concave direction of well trajectory.

Again, draw a unit vector perpendicular to both **t** and **n** as binormal vector **b**, viz. $\mathbf{b} = \mathbf{t} \times \mathbf{n}$. The three unit vectors form a right-hand system and constitute the moving frame of well trajectory at point P,[5 7 9 10] also known as "Frenet's frame."[12 13]

Finding out the relation between the moving frame and well trajectory requires embodying the equation of the moving frame. Equation 1 defines the well trajectory in vector form (accompanying box). According to differential geometry,[12 13] Equation 2 expresses the relationship among unit tangent vector **t**, unit principal normal vector **n**, unit binormal vector **b**, and displacement vector **r** of well trajectory.

Thus, the moving frame is in combination with the equation of well trajectory, which makes it feasible to describe the curvature and torsion of well trajectory in space by virtue of the moving frame (Fig. 2).

According to the differential model of wellbore trajectory, Equation 3 gives the relation between coordinate increments and curved-section length, inclination angle, and azimuth angle for a tiny interval. Substituting Equations 1 and 3 into Equation 2 yields Equation 4, which is the vector equation of moving frame on a well trajectory.

Kinematics equation

One can form a moving frame at any point P on a well trajectory. From the point of view of kinematics, when the point P moves along the well trajectory, the moving frame will move concordantly with it. It has been mathematically proven that Equation 5 or 6, viz. Frenet's equation, can depict the movement behavior of a moving frame.[12 13]

That is to say, the derivatives of unit vector **t**, **n**, and **b** with respect to

$$\tau = \frac{\kappa_\alpha \dot{\kappa}_\phi - \kappa_\phi \dot{\kappa}_\alpha}{\kappa^2} \sin\alpha + \kappa_\phi \left(1 + \frac{\kappa_\alpha^2}{\kappa^2}\right) \cos\alpha \tag{19}$$

$$\begin{cases} \theta = 0 \\ \tau = 0 \end{cases} \tag{20}$$

$$\begin{cases} \cos\theta = \frac{1}{\kappa_1 \kappa_2}[\kappa_\alpha^2 \cos\Delta\phi - \kappa_\alpha \kappa_\phi \cos(\alpha_1 + \alpha_2) \sin\Delta\alpha \sin\Delta\phi \\ \qquad + d\,\kappa_\phi^2 \sin\alpha_1 \sin\alpha_2] \\ \tau = \kappa_\phi \left(1 + \frac{\kappa_\alpha^2}{\kappa^2}\right) \cos\alpha \end{cases} \tag{21}$$

Where:

$$d = \sin\alpha_1 \sin\alpha_2 + \cos\alpha_1 \cos\alpha_2 \cos\Delta\phi$$

$$\begin{cases} \cos\theta = \frac{1}{\kappa_1 \kappa_2}[\kappa_V^2 \cos\Delta\phi - \kappa_V \kappa_H (\sin^2\alpha_2 \cos\alpha_2 - \sin^2\alpha_1 \cos\alpha_1) \sin\Delta\phi \\ \qquad + d\kappa_H^2 \sin^2\alpha_1 \sin^2\alpha_2] \\ \tau = \kappa_H \left(1 + \frac{2\kappa_V^2}{\kappa^2}\right) \sin\alpha \cos\alpha \end{cases} \tag{22}$$

$$\begin{cases} \cos\theta = \cos^2\omega \cos\Delta\phi - \sin\omega \cos\omega (\cos\alpha_2 - \cos\alpha_1) \sin\Delta\phi \\ \qquad + d \sin^2\omega \\ \tau = \kappa \frac{\sin\omega}{\tan\alpha} = \kappa_\phi \cos\alpha \end{cases} \tag{23}$$

$$\bar{\tau} = \mathrm{sgn}(\Delta\phi) \frac{\theta}{\Delta L} \tag{24}$$

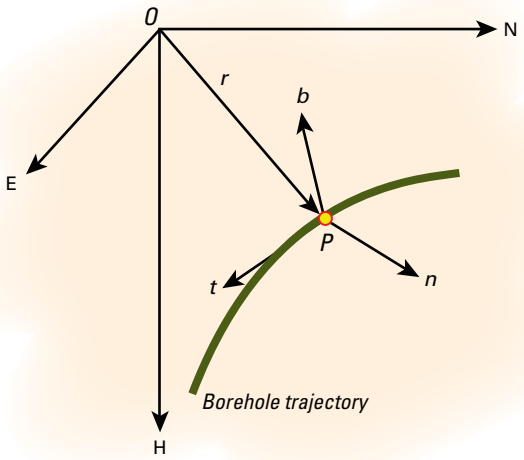
Where:

$$\mathrm{sgn}(x) \begin{cases} +1, & \text{if } x > 0 \\ 0, & \text{if } x = 0 \\ -1, & \text{if } x < 0 \end{cases}$$

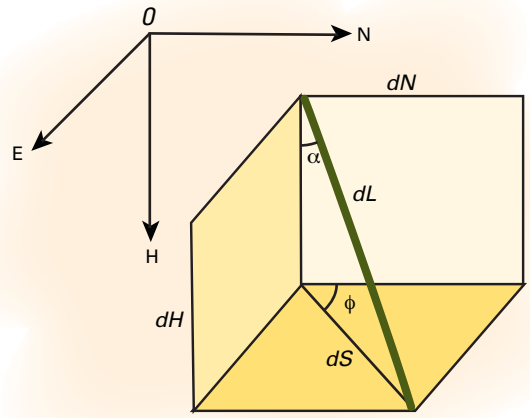
Nomenclature

- L = Measured depth, m
- α = Inclination angle, °
- ϕ = Azimuth angle, °
- ΔL = Curved section length, m
- $\Delta\alpha$ = Section increment of inclination angle, °
- $\Delta\phi$ = Section increment of azimuth angle, °
- N = North coordinate (south is negative), m
- E = East coordinate (west is negative), m
- H = Total vertical depth, m
- i = Unit vector on N axis
- j = Unit vector on E axis
- k = Unit vector on H axis
- r = Coordinate vector of wellbore trajectory
- t = Unit tangent vector of wellbore trajectory
- n = Unit principal normal vector of wellbore trajectory
- b = Unit binormal vector of wellbore trajectory
- ω = Instantaneous rotational velocity vector of moving frame
- $\dot{r}$ = First derivative of coordinate vector
- $\dot{t}$ = First derivative of unit tangent vector
- $\dot{n}$ = First derivative of unit principal normal vector
- $\dot{b}$ = First derivative of unit binormal vector
- $\ddot{r}$ = Second derivative of coordinate vector
- ε = Bending angle, °
- θ = Torsion angle, °
- κ_α = Rate of inclination change, °/m
- κ_ϕ = Rate of azimuth change, °/m
- κ_V = Curvature of wellbore trajectory in vertical expansion plot, $\kappa_V = \kappa_\alpha$, °/m
- κ_H = Curvature of wellbore trajectory in horizontal projection plot, °/m
- κ = Curvature of wellbore trajectory, °/m
- τ = Torsion of wellbore trajectory, °/m
- λ_α = Ratio of inclination change rate to wellbore curvature, dimensionless
- λ_ϕ = Ratio of azimuth change rate to wellbore curvature, dimensionless
- $\dot{\kappa}_\alpha$ = First derivative of inclination change rate, viz. second derivative of inclination angle, °/sq m
- $\dot{\kappa}_\phi$ = First derivative of azimuth change rate, viz. second derivative of of azimuth angle, °/ sq m
- R = Curvature radius, m
- ρ = Torsion radius, m
- ω = Tool face angle, °
- $\bar{\alpha}$ = Average inclination angle, °
- $\bar{\kappa}$ = Average borehole curvature, °/m
- $\bar{\tau}$ = Average borehole torsion, °/m
- a, b, c, d = Intermediate variable, dimensionless

MOVING FRAME ON BOREHOLE TRAJECTORY Fig. 2



INFINITESIMAL SECTION MODEL OF BOREHOLE TRAJECTORY Fig. 3

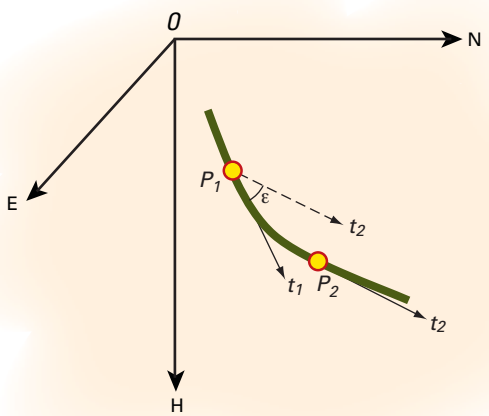


measured depth L can be expressed with linear combination of vector **t**, **n**, and **b**. In this way, combining Equation 5 or 6 with Equation 2 depicts the law of frame's motion while the point P moves along a wellbore trajectory (Fig. 3).

One can regard a moving frame as a rigid body turning around the point P, while it moves along a well trajectory. According to the principle of kinematics, Equation 7 indicates instantaneous rotational velocity of the moving frame in vector form. The vector of instantaneous rotational velocity is called Darboux's vector and lies in the rectifying plane and can be disassembled to two components $\tau\mathbf{t}$ and $\kappa\mathbf{b}$.

Thus, one can regard the instantaneous rotational velocity of moving frame as the sum of two kinds of rotations, namely, rotating around the axis in the $\tau\mathbf{t}$ direction and around the axis in the $\kappa\mathbf{b}$ direction. Therefore, the kinematics meaning of borehole curvature and torsion become explicit: Borehole curvature equals the component of moving frame rotating around the binormal, and borehole torsion equals the component of moving frame around the tangent line. In addition, Equation 8 gives Frenet's equation in another form.

BENDING ANGLE Fig. 4



Borehole curvature

The industry defines the included angle between two tangent vectors of wellbore trajectory at different two points as dogleg angle.[1-4] Generally, these two tangent vectors are not in the same plane, so that dogleg angle displays as a space angle (Fig. 4). Dogleg angle is also named as overall angle, which means that it includes both inclination change and azimuth change. In mathematics and drilling engineering, this is called the bending angle.

According to the definition of bending angle, Equation 9 calculates the bending angle between two points on wellbore trajectory. Substituting Equation 4 into Equation 9 yields Equation 10, which is identical with that given by Lubinski.[1]

Borehole curvature, representing the extent of a well trajectory's departure from a straight line, is the rate that the tangent vector of well trajectory rotates with respect to curved length. It depicts the bending extent of a wellbore trajectory. Equation 11, a definitive expression of borehole curvature, demonstrates that the rotating rate of the tangent vector with respect to curved length describes the bending extent of wellbore trajectory when a given point moves forward along a well trajectory.

Besides being an important index to check buildup rates on the bottomhole assembly (BHA), understanding the deflection behavior of the formation, and evaluating a wellbore trajectory's quality, borehole curvature serves as the basis for monitoring a drilled wellbore's trajectory and calculating the forces applied on the drillstring and its deformation. Deciding whether to trip pipe

and having the ability to run casing smoothly and successfully depends on borehole curvature; it is therefore a significant factor for safe, quick, and efficient drilling.

There are two ways of deducing the applied formula for calculating borehole curvature.[5 7 8] One is to substitute the expression of unit tangent vector, **t**, from Equation 4 into Equation 11, another is to substitute the formula of bending angle, **ε**, from Equation 10 into Equation 12, another definitive expression of borehole curvature. Through mathematical deduction, both methods yield Equation 13, which is the same as that presented by Wilson.[4] But it is necessary to point out that Equation 13 applies to calculate the borehole curvature at a given point.

Average curvature

During the process of drilling, engineers usually pay attention to the average curvature of a survey interval. Generally, borehole curvature varies with measured depth rather than a constant, which is the reason for calculating average curvature. At present, Equations 14 and 15 are popularly used to calculate the average curvature of a survey interval.

In order to calculate the average curvature scientifically and reasonably, the author draws the following conclusions based on theoretical analyses and lots of example calculation:[11]

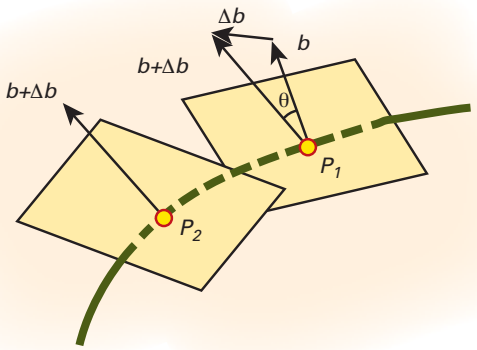
- In most cases, Equations 5 and 6 yield very similar results. Thus, it is acceptable to use either formula for calculating the average curvature of a survey interval.
- For natural-curve trajectories and cylinder-helix trajectories, the value of average inclination angle for a survey interval equals that of inclination angle at the midpoint as inclination angle is linear functions vs. measured depth. Thus, the result from Equation 14 actually represents the value of borehole curvature at the midpoints for natural-curve trajectories and cylinder-helix trajectories.
- It has been proven that Equation 15 fully conforms to spatial-arc model in theory[7] and verified with actual data.[11]
- There always exists some error when using Equation 14 to calculate the average curvature of a spatial-arc interval. The bigger **κ** and ΔL are, the larger the error. Except for **ω** = 0° or **ω** = 180°, errors exist at other tool face angles, and the biggest one may be beyond 60%.[11]

In conclusion, Equation 14 is a formula for calculating borehole curvature at a given point. It sometimes shows considerable error to calculate the average curvature of a survey interval through substituting average values of interval parameters into Equation 14.

Equation 15, however, is deduced from the mathematical definition of borehole curvature and is more reasonable in terms of theoretical analyses and calculated results. Therefore, the author recommends using Equation 15 to calculate the average curvature of a survey interval.

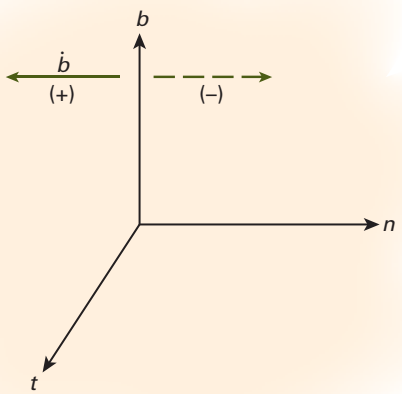
TORSION ANGLE

Fig. 5



SIGN OF BOREHOLE TORSION

Fig. 6



Borehole torsion

The industry defines the included angle between two binormal vectors of wellbore trajectory at different two points in its onward direction as the torsion angle (Fig. 5).[5 7] According to the definition of the included angle between two vectors, Equation 16 gives the torsion angle between the two given points on a wellbore trajectory. Substituting Equation 4 into Equation 16 yields Equation 17, which is the formula for calculating the torsion angle.

It is necessary to point out that bending angle cannot directly express the bending extent of a wellbore trajectory. Nevertheless, as an important indirect parameter, use of bending angle can simplify the calculation method and process of planning well path and performing survey calculations. In the same way, torsion angle is not a direct parameter of expressing torsion extent of a wellbore trajectory.

Borehole torsion, illustrating the extent of well trajectory's departure from a plane curve, is the rotating rate that the binormal vector of well trajectory rotates with respect to curved length. It depicts the torsion extent of wellbore trajectory.[5 7] Equation 18 is the defini-

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CALCULATED RESULTS OF TORSION PARAMETERS

Table 1

MD and inclination		Nature curve			Cylinder helix			Constant tool face		
ΔL m	Δα (°)	Δϕ (°)	θ (°)	τ °/30 m	Δϕ (°)	θ (°)	τ °/30 m	Δϕ (°)	θ (°)	τ °/30 m
0	20.000	0	0	–17.810	0	0	–21.757	0	0	–11.459
5	21.667	–1.667	2.940	–17.472	–1.404	3.720	–22.852	–1.956	1.828	–10.499
10	23.333	–3.333	5.822	–17.119	–2.915	7.606	–23.758	–3.773	3.506	–9.669
15	25.000	–5.000	8.643	–16.753	–4.532	11.624	–24.468	–5.472	5.055	–8.944
20	26.667	–6.667	11.399	–16.374	–6.252	15.742	–24.981	–7.067	6.489	–8.305
25	28.333	–8.333	14.089	–15.986	–8.076	19.924	–25.304	–8.573	7.821	–7.735
30	30.000	–10.000	16.710	–15.588	–10.000	24.140	–25.448	–10.000	9.061	–7.224

Note: ΔL, Δα, Δϕ, and θ: Increment of measured depth, inclination angle, azimuth angle, and torsion angle from the upper point (where $\alpha_1 = 20°$) to the calculated point, respectively. τ: Borehole torsion at the calculated point.

tion expression of borehole torsion.

The symbolic meaning of borehole torsion: when a point moves along a wellbore trajectory in the onward direction, if the derivative of unit binormal vector with respect to measured depth, $\dot{\mathbf{b}}$, is in the opposite direction of unit principal normal vector $\mathbf{n}$, the sign of borehole torsion, τ, is positive. Otherwise, the sign of τ is negative (Fig. 6).

Substituting the expression of unit binormal vector $\mathbf{b}$ in Equation 4 into Equation 18 yields Equation 19, which is the formula that calculates the borehole torsion at a given point.

The value of borehole curvature is constantly positive, but that of borehole torsion can be positive or negative. A zero borehole curvature, $\kappa = 0$, will depict a straight section and a zero borehole torsion, $\tau = 0$, will depict a plane curve.

Equations 17 and 19, universal formulas for torsion angle and borehole torsion, respectively, can be simplified for given mathematical models of wellbore trajectory. Equations 20-23 give the simplified formulas for spatial-arc trajectory, natural-curve trajectory, cylinder-helix trajectory, and constant-tool-face trajectory, respectively. The formula for borehole torsion presented in this article is different from that given by Fitchard and Fitchard for cylinder-helix trajectory (OGJ, Jan. 17, 1983, pp. 121-124).

Learnings

This study has led the author to conclude:

- In research on the shape of a wellbore trajectory, the wellbore trajectory described by spatial-arc model is a sort of plane curve that borehole torsion is zero, i.e., no tortuous behavior.
- Azimuth change is a prerequisite to the existence of borehole torsion. If azimuth angle remains constant, borehole torsion will be zero.
- For the natural-curve model, cylinder-helix model, and constant-tool-face model, borehole torsion is a function of inclination angle when the characteristic parameters of a well trajectory are determined.

Example

An example calculates the torsion parameters of a well trajectory, given the following input data:

- Length of survey interval: $\Delta L_{1,2} = 30$ m.
- Inclination at the upper survey station: $\alpha_1 = 20°$.
- Inclination at the lower survey station: $\alpha_2 = 30°$.
- Azimuth change: $\Delta\phi_{1,2} = -10°$.

As mentioned, there is no torsion in the spatial-arc model, and there exists the same law of inclination change in natural-curve model, cylinder-helix model, and constant-tool-face model. Therefore, azimuth angle, torsion angle, and borehole torsion vary with measured depth or inclination angle. Table 1 shows the calculated results.

With regard to a survey interval of a drilled well trajectory or a section of a planned well path, one must calculate the average borehole torsion. With the definition of borehole torsion and the calculation method of average borehole curvature as a reference, the formula for calculating average borehole torsion will be similar to Equation 15. Thus, Equation 24 gives the formula to calculate average borehole torsion as the value of torsion angle is always positive and that of borehole torsion can be positive or negative.

Calculating borehole curvature and torsion provides a basis for effectively monitoring and controlling wellbore trajectories, analyzing the forces applied on drilling string and its deformation, calculating drag and torque of pipe string and checking its strength.[14,15] Therefore, applying these results can produce higher well trajectory quality, and result in safer, faster, and more efficient drilling. ✦

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Bankers targets unconventional gas in Palo Duro basin

Finding the right hydraulic fracturing method is key for unlocking the unconventional gas resources contained in the Lower Pennsylvanian Bend group sands and shales of the Palo Duro basin in West Texas.

One company trying to exploit this potential is Bankers Petroleum Ltd., a Calgary-based oil and gas exploration and production company.

The company has acquired under lease about 260,000 net acres from Vintage Petroleum LLC and plans to increase this to 300,000 net acres.

Palo Duro basin

The Palo Duro basin is about 260 miles northwest of the Fort Worth basin Barnett shale play. Improved fracture stimulation technologies transformed the Barnett shale into the largest producing natural gas field in Texas, estimated to contain 1 tcf of recoverable gas in the 45,000-acre core area. Table 1 compares the Palo Duro basin with other organic shale areas. Bankers says the Palo Duro basin gas play currently encompasses four counties: Briscoe, Floyd, Motley, and Hall. The play targets Pennsylvanian-aged shales that are at 7,000-10,500 ft depths.

The entire Palo Duro basin covers 22,700 sq miles in the Texas Panhandle, eastern New Mexico, and Oklahoma. North of the basin is the Amarillo uplift, to the south is the Matador arch, and to the east and west are minor structural highs that separate it from the Hardeman and Tucumcari basins.

The central portion of the province does not currently produce oil or gas in commercial quantities, but Bankers says production does exist along the Matador arch, as well as along the northern border south of the Amarillo uplift in Mississippian, Pennsylvanian, and Permian rocks.

Basin assessment

To date, several companies have drilled wells in the basin and Bankers expects that it will be another 9-12 months before it ascertains the viability of the basin for producing gas.

Bankers says the discovery well for the Bend group was the Cogdell well drilled by Legacy Petroleum Corp. in mid-2003 (Fig. 1). The well, completed in the Bend group in three intervals including some sands, was stimulated with small fracture treatments in each interval. The reported combined flow rate was 2.8 MMcfd.

Bankers believes this 3-day test was insufficient to asses the well and has used this test only to confirm that the basin contains producible hydrocarbons. The well was subsequently shut-in for more than 400 days while the property changed hands.

Upon reentry, the new operator, Vintage Petroleum LLC, needed to swab water from the well and found that a bridge plug isolating the Bend group from the Morrow sands had failed. Bankers believes water from the Morrow covering the productive perforated interval had damaged the reservoir and was the cause for the zone producing only 60-120 Mcf after it was isolated with a new bridge plug and cleaned up.

Another well is the area is Echols, for which one estimate indicates that the gas in place is 130 bcf/section. Echols was Vintage's first follow-up well and was fracture stimulated in the Bend group.

Bankers says flow back showed some crushed proppant frac sand and black sludge determined to be Magnetite, apparently caused by a reaction of the frac fluid with the minerals in the reservoir. Bankers currently is analyzing and trying to reverse engineer what reaction took place so as to prevent such reactions in the future.

Even with these problems and after partial recovery of the frac fluid the well slowly started to produce gas, which increased to 120 Mcfd as more of the frac fluids were recovered. Gas flow stopped as water entered the casing at about 4,500 ft, about 3,500 ft above the Bend group completion. A cement squeeze failed to shut in the water, and Bankers attributes the failure to the difficulty of doing squeeze jobs in 5½-in. casing.

The Burleson Ranch well is another Vintage drilled well with an estimated gas in place of 130 bcf/section. Vintage fracture stimulated the Bend group but also pumped 2,000 bbl of acid ahead of the frac.

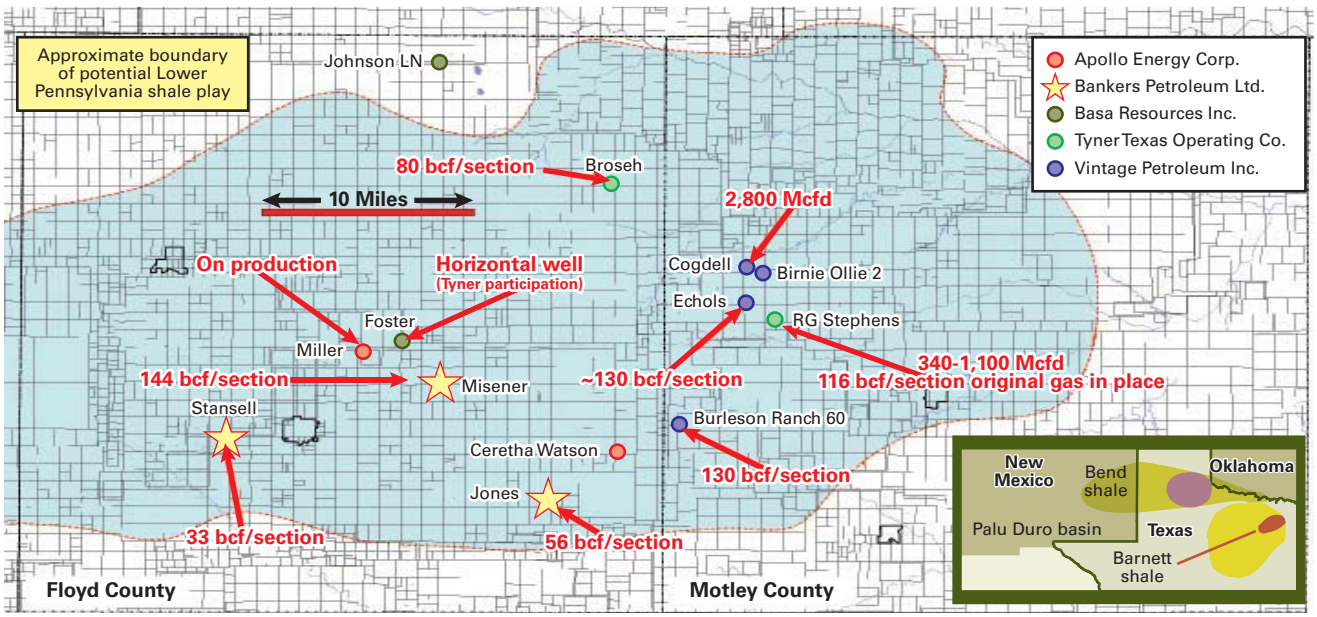
US ORGANIC SHALES

	Barnett	Ohio	Antrim	New Albany	Lewis	Fayetteville	Palo Duro
Depth, ft	6,500-8,500	2,000-5,000	600-2,200	500-2,000	3,000-6,000	1,500-6,500	7,000-10,500
Gross thickness, ft	150-700	300-1,000	160	180	500-1,900	50-325	500-1,000
Net thickness, ft	100-600	30-100	70-120	50-180	200-300	20-200	200-?
Bottomhole temperature, °F.	200	100	75	80-105	130-170		180
Total oraganic carbon, %	4.5	0.0-4.7	1-20	1-25	0.45-2.5	4.0-9.5	2.5-4.5
Porosity, %	4.5	4.7	9	10-14	3.0-5.5	2.8	
Reservoir pressure, psi	3,000-4,000	500-2,000	400	300-600	1,000-1,500	600-2,000	3,000-3,250
Gas in place, bcf/section	50-150	5-10	6-15	7-10	8-50	25-60	80-180
Resources, MMcf	500-4,000	150-600	200-1,200	150-600	600-2,000		

Sources: Pickering Partners Inc., Bankers Petroleum Ltd., Vitage Petroleum Inc., and Tyner Resources Ltd.

BEND SHALE POTENTIAL

Fig. 1



Source: Bankers Petroleum Ltd.

Bankers says the mineralogy from logs and cores indicates that the zone has much pyrite and chlorite that would have reacted badly with the acid. The well did produce some gas after a substantial amount of frac fluid was recovered during 3½ months. Production increased to 24 Mcfd before the well was shut in due to the sale of Vintage.

Tyner Resources Ltd.'s Tyner Stephens well, with an estimated 116 bcf/section in place, is the most successful well to date in the area. A Tyner press release says that after fracture stimulation the Bend shale produced between 400 Mcfd and the absolute open flow of 1.5 MMcfd, after recovery of 2,300-4,000 bbl of frac fluid.

The current gas flow is 340 Mcfd at a 40-psi wellhead pressure and 1.15 Mcfd at 12 psi. Tyner says the well was perforated in a 150-ft vertical section with four 12-ft sections in the primary Bend group target. The lower 12-ft section penetrated a sand interval that was not fraced to ensure that no fracture stimulation energy was dissipated in the sand, according to Tyner.

The company's reentry program isolated the shale perforations and monitored a flow test of the shale for 4 days, while implementing a low-pressure pipeline simulation at the surface. Tyner says the isolated shale zone flowed 250 Mcfd of 1,400-btu gas without any production decline during the test.

Tyner expects to meet pipeline-btu gas specifications by stripping off about 28 bbl of NGL at the pipeline connections. The test also yielded 20 bo/d.

The lowest perforation in the sand interval produced 200 Mcfd also of 1,400-btu gas. Tyner expects this sand interval, when successfully fraced, to produce an additional 0.8-1.4 MMcfd.

Tyner fraced its Broseh well with 804 bbl of KCl treated water, 1.36 MMcf of nitrogen, and 82,405 lb of Carobilite 20/40 sand. Perforations screened off while pumping 3-ppg sand, leaving 51,405 lb of sand in the formation.

Since completing the frac, Tyner says the well has recovered 1,100-1,500 bbl of frac fluids and after a 48-hr shut-in, the wellhead pressure was 1,100 psi, while after 12 hr it was 480 psi. The pressure blows off in 4 hr with an open choke.

The company is swabbing 40-45 b/d of fluid and experiences shut-in pressure increase daily, with a good gas blow after each swab run.

Bankers currently is evaluating various stimulation designs for its Misener well because the well is slightly different from other wells in that it is more fractured. The well has one to two fractures/ft throughout the Bend group. A Schlumberger FMI log shows that these are fairly large ½-1 mm fractures.

Bankers plans to stimulate and test the Granite Wash sands and the Bend shale in this well separately. The deepest Granite Wash sands tested have shown little water. These are 600 ft below the identified Bend shale test interval.

Bankers may use gelled-diesel fracs, straight slickwater fracs, as well as cross-linked gelled-water fracs for stimulating this well.

It plans to restimulate the Cogdell well after stimulations in the Misener well. Along with the original tested interval in the Cogdell well, Bankers also will test what it considers the sweet spot in the shale in this well.

After Cogdell, Bankers will move to its Jones No. 1 well that it drilled to test the Bend shale.

Bankers says that by pursuing this basin methodically and scientifically and acquiring knowledge from the previous stimulations and tests, it will find a way to produce gas from the basin economically. ✦

Ionic liquid alkylation process produces high-quality gasoline

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A new composite ionic liquid (IL) alkylation process has been proven in a pilot plant and retrofitted into an existing 65,000-tonne/year H_2SO_4 alkylation unit in China. This article discusses the new process, ionikylation, and presents results from the pilot plant and retrofitted unit.

Process reactions take place at ambient temperatures and moderate pressures. Alkylate from the ionikylation process compares favorably to alkylate from HF and H_2SO_4 units but without the safety and environmental concerns.

Alkylation

Isobutane alkylation is a common refinery process used to produce high-quality gasoline (OGJ, Nov. 12, 1990, p. 79). The most desirable components in alkylate gasoline are trimethylpentanes (TMPs), which have research octane numbers (RONs) greater than 100.

Conventional alkylation processes use either H_2SO_4 or anhydrous HF acid as catalysts. This has significant safety and environmental concerns due to the handling of large quantities of spent H_2SO_4 or hazardous HF.

Solid acids have shown promise as less hazardous catalysts for alkylation[1] and have been subjected to extensive pilot scale testing.[2,3] Solid-acid catalysts, however, deactivate rapidly, resulting in low product yield and loss of reaction selectivity.[4]

The rapid deactivation is due to a buildup of carbenium ions on active sites of the solid catalysts. Once this carbonaceous material is formed, it is difficult to remove from the narrow catalyst pores. Moreover, the cost of solid-acid catalysts is relatively high and there is no technically sound method for regenerating spent solid-acid catalysts.

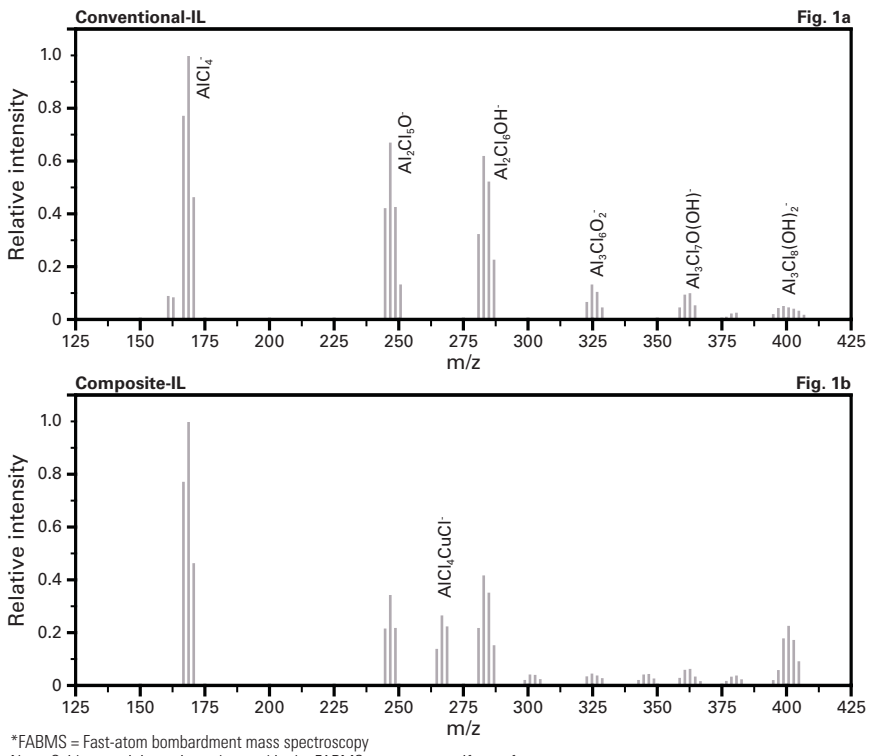
Ionikylation

Ionikylation is an environmentally friendly and energy efficient isobutane alkylation process. The process uses a composite-IL as homogeneous catalyst for alkylation reactions at ambient temperatures and moderate pressures.

ILs are ionic, salt-like materials that are liquid at less than 100° C.[5] ILs have been histori-

FABMS* OF IL CATALYSTS

Fig. 1



*FABMS = Fast-atom bombardment mass spectroscopy
Note: Oxide-containing anions observed in the FABMS spectra are artifacts of water contamination due to high sensitivity of chloroaluminate (III) IL with water.

cally used as solvents and homogeneous catalysts[6] due to their negligible vapor pressure, good solubility to a wide range of organic and inorganic compounds, and ability to be recycled for reuse.[7]

Acidic chloroaluminate (III) IL has been used as a homogeneous catalyst for isobutane alkylation. Its use eliminates the diffusion limitation present with solid-acid catalyst systems, and alkylated gasoline is easily separated from the ionic liquid.[8-10]

TMP yield and selectivity, however, are low in systems with conventional-IL—with and without adjusting the IL's acidity by varying either the molar fraction of aluminum chloride ($AlCl_3$) of the IL or adding hydrochloric acid (HCl).[10-12]

A study showed that adding aromatic hydrocarbons and metal chlorides to aluminum chloride-dialkyl ether complex enhanced TMP selectivity. It is theorized that adding aromatic hydrocarbons and metal chlorides enhances the acidity of catalyst for alkylation reactions and inhibits undesirable side reactions such as isomerization and cracking.[13]

In subsequent experiments, aromatic hydrocarbons and cuprous chloride (CuCl) were added to a conventional-IL, which showed high TMP yield and selectivity.[10 11 14] Adding CuCl to an aluminum chloride-dialkyl ether complex or conventional-IL, however, results in formation of a fine suspension that is difficult to separate and recycle in a continuous-flow system.

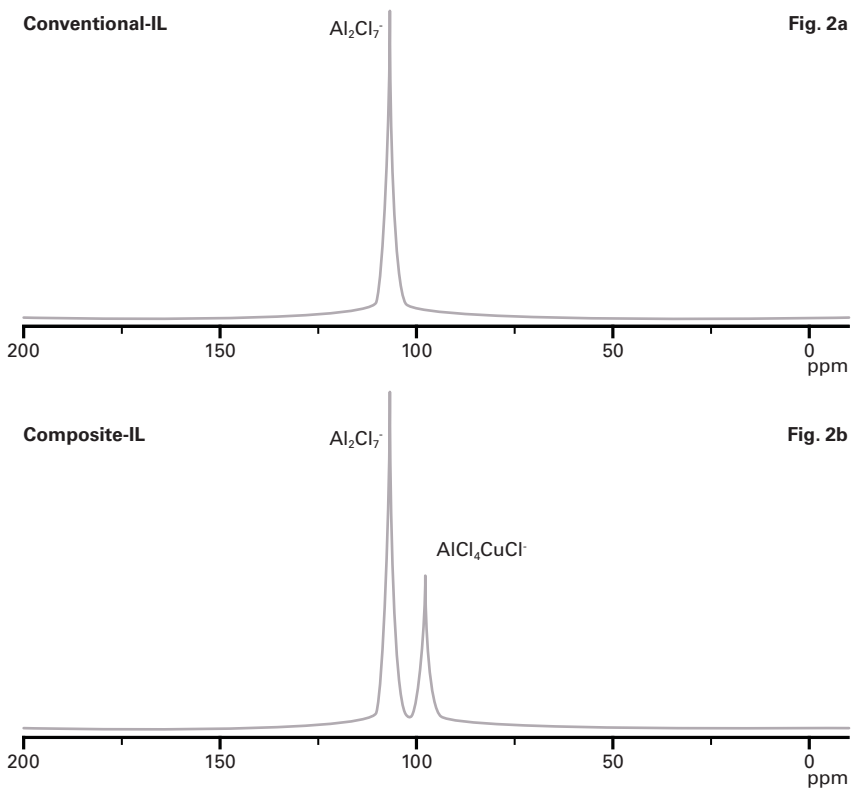
Composite-IL catalyst

A further development in the commercialization of IL-catalyzed isobutene alkylation is the development of a composite-IL catalyst. It is a liquid compound, which is synthesized with a conventional-IL catalyst and CuCl.[15] The composite-IL catalyst has anions in the form of ligands with two or more metallic centers.

Fast-atom bombardment mass spectrometry (Fig. 1) and ^{27}Al nuclear magnetic resonance (NMR, Fig. 2) show

^{27}Al NMR SPECTRA OF IL CATALYSTS

Fig. 2



that a relatively high quantity of multicenter ligands of $AlCl_4CuCl^-$ are formed in the composite-IL catalyst. By comparison, only a few $AlCl_4CuCl^-$ ligands were detected in the IL-CuCl system when CuCl was added to a conventional-IL catalyst.[16]

Pilot plant

Extensive bench-scale laboratory tests were conducted to optimize the composite-IL catalyst's performance in alkylating isobutane.[10] The ionikylation process was demonstrated in a continuous-flow pilot unit with 4-l./hr equivalent alkylate gasoline production for 60 days.

Fig. 3 shows the process flow diagram of the pilot unit. The pilot unit was constructed from carbon steel.

The composite-IL catalyst used in the pilot test unit was prepared commercially with industrial-grade chemicals. This was done to determine the effect of impurities on the composite-IL catalyst due to isobutane alkylation reactions. The composite-IL catalyst was also subjected to an aging test by storing it in a tank for 8 months before the pilot test.

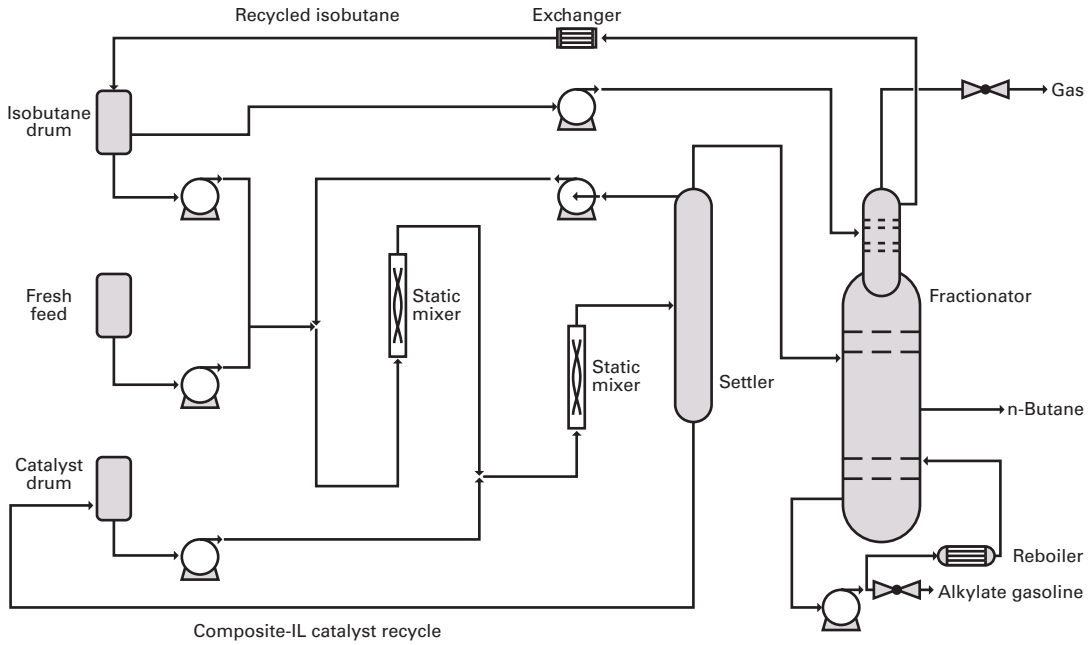
Fresh feed was a mixture of isobutane and a heavy C_4 fraction (primarily butene-2) in a 1:1 ratio. These streams were obtained from a commercial refinery. Fresh feed, recycled isobutane, and a mixture of excess isobutane and alkylate gasoline from the top of the settler were fed to the first static mixer.

The stream from the first static mixer was combined with the recycled composite-IL catalyst and fed to the second static mixer where the isobutane alkylation reactions occurred at 15° C. and 0.4 MPa.

Reaction products then flowed to a settler. The composite-IL catalyst, which is heavier than alkylate gasoline, was collected from the bottom of the settler and recycled and reused. A split stream of excess isobutane and alkylate gasoline at the top of the settler were recycled to the first static mixer. Remaining

PILOT PROCESS FLOW DIAGRAM

Fig. 3



ALKYLATE COMPARISON

Table 1

Yield, wt %	Process: Ionikylation	Process: HF*	Process: H_2SO_4*
C_5	0.6	2.5	8.8
C_6	1.0	1.9	4.9
C_7	2.0	2.9	3.9
C_8	95.6	90.1	80.7
C_{9+}	0.8	2.6	5.7
C_8 components			
TMPs	89.6	80.9	71.6
2,2,3-TMP	0.1	1.6	2.3
2,2,4-TMP	51.6	49.7	31.1
2,3,3-TMP	18.1	10.8	19.8
2,3,4-TMP	19.8	18.8	18.4
DMHs	6.0	9.2	9.0
2,3-DMH	1.3	–	–
2,4-DMH	3.4	–	–
2,5-DMH	1.3	–	–
3,4-DMH	0	–	–
TMP:DMH ratio	14.9	8.8	8.0
RON	100.1	97.3	97.6
MON	95.0	95.2	94.4

*Data source: Reference 17.

products from the top of settler were fed to a fractionation column.

Isobutane at the top of the fractionation column was cooled and recycled to the first static mixer. It maintained a relatively high isobutane-to-olefin (I:O) ratio and low reaction temperature. Product n-butane and alkylate gasoline were obtained from the middle and bottom of fractionation column, respectively.

The overall I:O ratio of reactants in the reactor was 500, which was controlled with the flow rate of recycled isobutane and the mixture of excess isobutane and alkylate gasoline. The reaction time was 10 min, which depended upon the residence time in the second static mixer and sedimentation time in settler.

The volumetric ratio of composite-IL catalyst to the stream from the first static mixer was 1.2. This was done to maintain the composite-IL catalyst as a continuous liquid phase, which helped achieve high TMP selectivity.

Ionikylation performance

Olefin conversion was constantly more than 99% for the entire pilot test period.

Table 1 summarizes the product yield and properties of alkylate gasoline. The C_8 yield in alkylate gasoline was higher than 95 wt % and the yield of TMPs was 90%.

The ratio of TMPs to dimethylhexanes (DMHs) in alkylate gasoline is an important key criterion for comparing the performance of alkylation catalysts. Alkylate from the composite-IL catalyst had a high TMP:DMH ratio, indicating that a relatively small amount of undesirable side reactions such as isomerization and cracking occurred. The high C_8 yield and TMP selectivity of composite-IL catalyst are due to high concentration of $AlCl_4CuCl^-$ ligands.

Performance of the ionikylation process in the continuous pilot test was comparable to that of the bench-scale test. This shows that the commercial composite-IL catalyst performed in a similar manner as that developed in the laboratory, and its activity was stable.

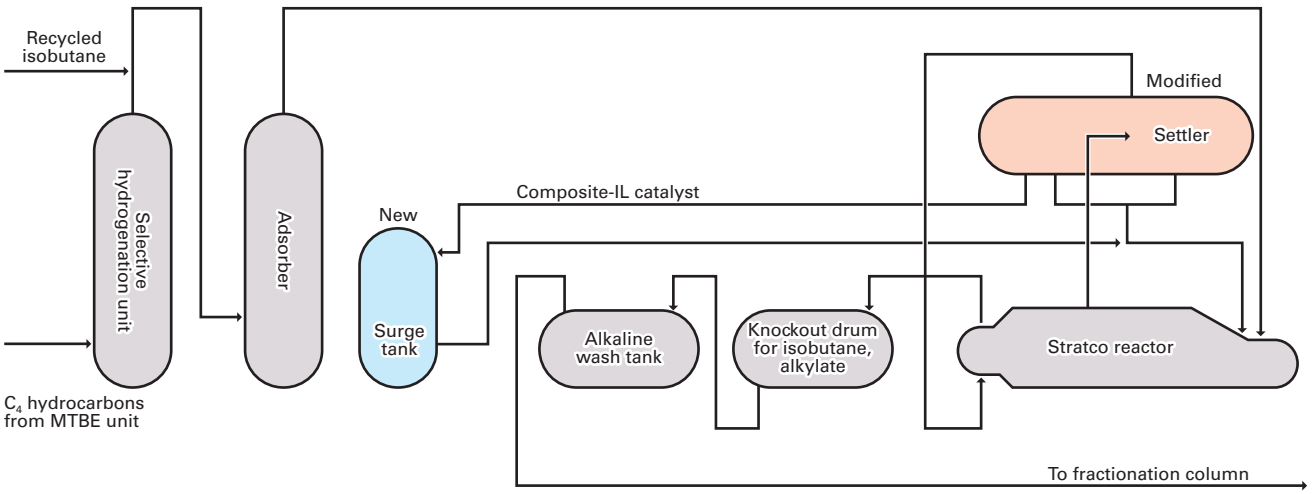
ALKYLATE GASOLINE FROM IONIKYLATION PILOT

Table 2

		Test standard
Octane rating		
RON	100.1	GB/T 5478
MON	95.0	GB/T 503
Antiknock index	97.6	GB/T 547, GB/T 503
Distillation curve, °C.		GB/T 6536
10%	98.6	
50%	104.1	
90%	111.0	
Final boiling point	129.4	
Residual, vol %	1.8	
rvp, 1,000 Pa	25.5	GB/T 8017
Actual gum, mg/100 ml	1	GB/T 8019
Induction period, min	>1,000	ASTM D-526
Sulfur content, wt %	0.003	GB/T 17040
Doctor test	Pass	SH/T 0174
Copper corrosion at 50° C., 3 hr, grade	1a	GB/T 5096
Aromatics, vol %	0.3	GB/T 11132
Alkenes, vol %	0	GB/T 11132

RETROFITTED COMMERCIAL IONIKYLATION UNIT

Fig. 4



Neither the composite-IL catalyst nor its decomposed species was detected in alkylate gasoline, indicating good separation of composite-IL catalyst from alkylate gasoline and chemical stability of composite-IL catalyst. Metallurgical inspection of the pilot unit indicated that no detectable corrosion occurred in the process units during the 60-day continuous pilot test.

Also included in Table 1 are performance data of H_2SO_4 and HF catalyzed isobutane alkylation processes.[17] In general, the ionikylation process produces a higher-quality alkylate gasoline than either H_2SO_4 or HF alkylation processes.

Table 2 lists the detailed properties of alkylate gasoline produced by the ionikylation process. The quality of product from the ionikylation process exceeded the specifications for gasoline, such as higher RON and MON, lower rvp, and temperature at 50% and 90% distillation yield.

Benefits

Operating conditions in the ionikylation process are similar to those of commercial H_2SO_4 and HF alkylation processes. The reactor used in ionikylation, however, is a commercial static mixer that is much simpler and cheaper than the reactor used in the H_2SO_4 alkylation process.

Because ionikylation uses a composite-IL catalyst that is noncorrosive, carbon steel can be used for the hardware such as reactors, piping, tanks, pumps, and valves. The control corrosion test of the composite-IL catalyst on carbon steel indicated that the corrosion rate was less than 0.001 mm/year.

Ionikylation can be easily retrofitted to an existing H_2SO_4 or HF alkylation unit.

Commercialization

The successful demonstration of the ionikylation process prompted PetroChina to retrofit an existing 65,000-tonne/year (tpy) H_2SO_4 alkylation unit (Fig. 4). A new surge tank was added to recycle the composite-IL catalyst and allow the spent catalyst to settle.

The internals of the settler were modified to enhance the separation of composite-IL catalyst from alkylate gasoline. The operating conditions in the selective hydrogenation unit were modified to meet the required concentration of 2-butene in the feed C_4 fraction for ionikylation.

Table 3 shows commercial performance data before and after the retrofit. The yield and RON of commercial ionikylation alkylate gasoline are 75 wt % (based on the amount of C_4 fraction from the MTBE unit upstream) and 98.8, respectively. This is higher than the yield and RON from H_2SO_4 alkylation (73 wt % yield and 95 RON) before the retrofit.

The retrofit also increased the process unit's capacity by 40%, to 248 tonnes/day (tpd) from 180 tpd. The economics of increased yield and RON of alkylate gasoline

ALKYLATE FROM COMMERCIAL H_2SO_4 UNIT

Table 3

		— Before retrofit — — H_2SO_4 alkylation — Flow rate, tpd	Yield, wt %	— After retrofit — — Ionikylation — Flow rate, tpd	Yield, wt %
Feed	C_4	180	—	248	—
Product	Light alkylate	125.9	70.0	186.1	75.0
	Heavy alkylate	10.8	6.0	8.2	3.3
	Gas	41.7	23.2	53.7	21.7
	Loss	1.4	0.8	—	—
	Total	180	100	248	100
Octane rating					
RON			95.0		98.8
MON			93.0		93.1
Antiknock index			94.0		96.0
Distillation, °C.					
Initial boiling point			45.0		45.5
10%			77.0		81.5
50%			101.5		101.0
90%			108.5		108.0
Final boiling point			132.0		154.0
Actual gum, mg/100 ml			0.9		1.6
Doctor test			Pass		Pass
Copper corrosion at 50° C., 3 hr, grade			1		1

from ionikylation are attractive, even though the cost of the composite-IL catalyst is more than H_2SO_4.

Compared with the pilot test results, the commercial performance of retrofitted ionikylation was less than optimal. This is due to the use of an existing Stratco reactor system, which has a long reaction time.

This results in increased side reactions such as cracking and isomerization, which form light and heavy components in alkylate gasoline. These are evident from the shift in distillation temperature at 10% yield (81.5° C. vs. 98.6° C.) and final boiling point (154° C. vs. 129.4° C.) when comparing the pilot results with those of the retrofitted unit.

We are currently conducting process optimization work to improve the commercial performance of ionikylation further by varying the size and type of static mixer and potentially replacing the Stratco reactor with a static mixer to minimize reaction time.

Acknowledgments

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Pipeline engagement eases move to ULSD

Christopher E. Smith
Pipeline Editor

Active participation by the US pipeline industry in the transition to the use of ultralow-sulfur diesel (ULSD) has helped the change occur smoothly. The pipeline industry participated in the development of regulations governing ULSD, establishing a designate-and-track procedure to ensure sulfur-content requirements of 15 ppm are met when the material is sold following transportation.

Designate-and-track is a system designed to designate the classifications of distillate flowing through the US pipeline system and track the progress of various batches thus designated.

Background

The initial question regarding the pipeline transition to ULSD could best be characterized as "can the product get from here to there without being degraded."

A 2001 US Energy Information Administration report on the process surrounding the transition pointed out three key uncertanties[1]:

- Protecting the product integrity of 15-ppm product would be more difficult than protecting the product integrity of 500-ppm highway diesel. Not only is the sulfur specification lower, with less room for error, but the relative potency of the sulfur in products further upstream is also potentially higher.
- The behavior of sulfur molecules in ULSD had not been field-tested to allow conclusions about whether pipeline wall contamination is a real problem or simply a fear, and whether the migration of sulfur will require a significant increase in the volume downgraded at interface.
- The accuracy and availability of test equipment were unproven.

Response

As of Oct. 15, 2006, regulations required retailers selling ULSD to adhere to the refinery-gate standard of 15 ppm.

In order to do so effectively, the pipeline industry's designate-and-track program had to consider a wide variety of variables, including:

- Product mix transported and its sulfur contents.
- Length of the pipeline, as well as the number of handoffs between pipelines or traverses through breakout tanks.
- Size of the pipeline.
- Flow rate.
- Fungible vs. segregated or batch system.

ULSD initially left the designate-and-track process upon leaving the truck terminal. Subsequent revision, however, has allowed for registration of mobile facilities as well.

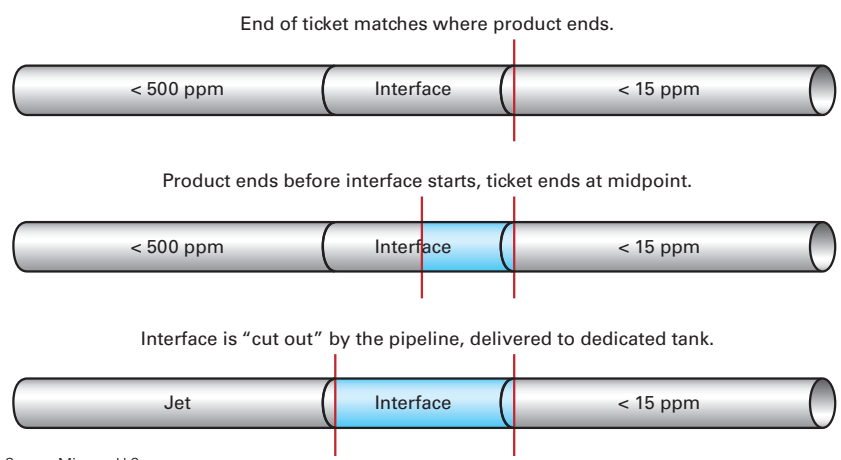
Designate-and-track requires each facility in the ULSD chain—refiners and blenders, pipelines, terminals, trucks, rail cars, and marine transports—to file reports indicating total distillate volumes, by designation category, delivered or received in a given quarter and year.

Compliance objectives include:

- Generating accurate and complete designations, records, and reports.
- Meeting the applicable sulfur standard.
- Maintaining designation balances and anti-downgrading limits.

The US Environmental Protection

POTENTIAL PIPELINE CUTS BETWEEN DISTILLATE TYPES Fig. 1



Source: Miesner LLC

Agency will produce computerized reviews of reports, as well as performing audits and inspections.

Each party in the ULSD chain sets and manages its own sulfur-receipt specs. Reports and records must show that handoffs of material match for each compliance period and transaction. Terminal handoffs must match the pipeline specs, but the terminal can change material designations as long as it meets compliance period balances. Terminal-to-trucker handoffs must show "substantial agreement" and include an explanation if this level of agreement is not met.

Figs. 1 and 2 show potential approaches to executing cuts between distillate types and between gasoline and distillate, respectively.

Reports and records must also show that material balances were maintained for the compliance period. Designate-and-track allows a 2 vol % tolerance for pipelines to account for volume swell, metering, and other measurement variables.

Designate-and-track also allows downgrading of up to 20% of material.

Off-spec material

Delivery of off-spec material will likely result in a shutdown of receipt or delivery to prevent additional off-spec material being shipped. This would trigger additional sampling and testing to verify the original results.

If additional tests confirm the material as off-spec, testing by an outside laboratory may occur to further verify the results. At this point, the shipper and the pipeline would likely collaborate to determine what options might be available.

The party in possession of off-spec ULSD at the time of testing is presumed to be liable for violations of the sulfur standard. The party in possession is responsible for accurately representing how the product can be legally used.

In general, if a pipeline samples and tests the product upon receipt and finds it to be compliant ULSD but later finds that it is no longer on-spec, the pipeline would be required to regrade the product to LSD or off-road and would be liable for the regrade cost.

The pipeline becomes liable in a legal sense, and susceptible to EPA fines, if it fails to recognize the off-spec situation and continues to represent the fuel as being ULSD compliant when it is not.

In the event that the party in possession wants to contest its liability, possible defenses include producing documentation that accounts for the product and shows that it didn't cause the material to go off-spec.

If the parties involved in handling the product cannot agree as to where it went off-spec and go to the EPA to settle the dispute, the EPA will examine the adequacy of the parties' quality-assurance and quality-control programs as part of making its decision.

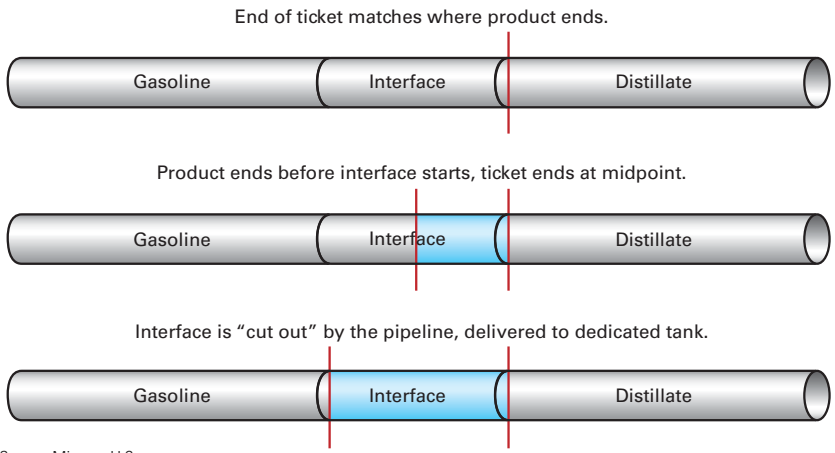
If an EPA test shows violation, while the terminal test of the same fuel shows compliance, the terminal may also be able establish a periodic sampling and testing program as part of its defense.

The EPA will allow 3-ppm variability in sulfur testing between labs for the first 2 years of the ULSD program, after which 2 ppm of variability will be allowed.

Redesignation or downgrading of material as a result of contamination by interface with a higher-sulfur product is allowed, subject to the 20% limit of the designate-and-track program. The shipper, working with the supplier-refiner, determines what redesignation to give an off-spec material.

POTENTIAL PIPELINE CUTS BETWEEN GASOLINE, DISTILLATE

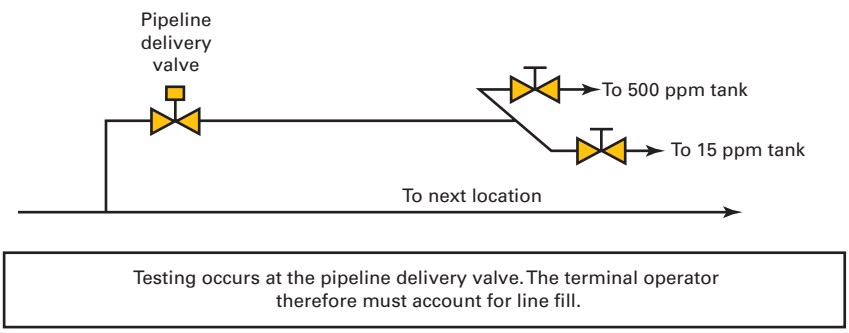
Fig. 2



Source: Miesner LLC

DELIVERY LINE FILL

Fig. 3



Source: Miesner LLC

Colonial Pipeline Co. replaced more than 300 valves in preparing to transport ultralow-sulfur diesel. The new valves are positive-sealing valves, which minimize any contamination of ULSD by other products. This picture shows Colonial's out-going valves on Line 27 at Mitchell Junction in central Virginia (Fig. 4; photo from Colonial Pipeline Co.).

Proper change-of-service procedures for ULSD required a detailed design review of each pipeline manifold, such as that pictured at Colonial's Mitchell Junction in central Virginia. In addition to using positive-sealing valves, the elimination of dead legs helps ensure effective manifold flushing (Fig. 5; photo from Colonial Pipeline Co.).

Parties are only to report volumes downgraded while in custody of their facilities. The receiving facility determines redesignation in the event that the product is upgraded. Product can also be blended back to specification or regraded to another product grade.

Clean Air Act guidelines allow for a maximum civil penalty of $32,500/day/violation. In an effort to remove any economic benefit of non-compliance, however, designate-and-track presumes that the material was in the distribution system for 25 days, raising the potential per violation fine to $800,000.

Custody-transfer points offer the highest likelihood of challenges under designate-and-track. Fig. 3 shows a simplified example of delivery line fill. Testing at the pipeline's delivery valve requires that the terminal operator understand and be able to account for line fill.

Supplying facilities are required to submit a Certificate of Analysis (CoA) identifying the product as meeting the requirements of the pipeline. Pipelines conduct product sampling and testing as an oversight to ensure the CoA is representative. Sampling and testing occur upon receipt, in transit, and upon delivery.

Carriers' sulfur cut-off spec for receiving material from the refiner-blender varies but is typically 8 ppm. Pipelines that do not transport other high-sulfur products, for example gasoline and ULSD only, can afford to set a more liberal specification. Pipelines that transport products that can add sulfur need to be more conservative. Small-refiner gasoline could also be a source of sulfur.

Short pipelines will typically experience a lower level of sulfur pickup from interfaces. Long-haul pipelines will typically experience a greater loss of ULSD due to more numerous sulfur interfaces.

Large-diameter pipelines will generate more sulfur interface due to the greater surface area where the products meet.

It is common for products to move on several pipeline systems between the refinery and the final destination. This is most common with Petroleum Admin-

istration for Defense District (PADD) III production moving to PADDs I and II. Each handoff between pipelines risks addition of sulfur from valve timing and line flushes between locations. Staging products in breakout tanks within a pipeline system can also add sulfur.

Fungible pipelines run on product cycles where receipt volumes are commingled and stripped off at delivery terminals en route. Commingling like products requires strict oversight and testing to protect the fungible pool from contamination.

Segregated systems receive specific batches and usually deliver them back to the supplier at a new location. The batches are not commingled and will move intact, with the specification properties unchanged. There is, however, still a chance that sulfur can be increased, depending on how products are sequenced, valve timing, and flushes between facilities.

Some carriers are very explicit in circumstances where material might be above their cut-off spec but still below 15 ppm, having zero tolerance for variation. Others are somewhat more flexible and willing to provide a waiver depending on the degree to which the product is off-spec, destination options, and other variables.

Colonial Pipeline Co. and Olympic Pipe Line Co. each have specified a maximum of 8 ppm for ULSD entering their systems. Explorer Pipeline Co. allows 8 ppm for ULSD received directly from refineries into its system but drops the limit to 7 ppm for ULSD originating in Lake Charles, La., and Port Neches, Tex.

Buckeye Pipe Line Co. will take ULSD up to 8 ppm from refineries and up to 10 ppm from connecting carriers. At Marathon Pipe Line LLC, the acceptable sulfur content depends on the source and delivery point (OGJ, May 22, 2006, p. 18).

The transition

Concerns surrounding the transportation of ULSD through pipelines have included:

Transportation of ULSD via pipeline heightens any potential product-quality problems on the pipeline's systems, making proper flushing of prover loops such as the one shown here very important (Fig. 6; photo from Colonial Pipeline Co.).

- Protecting the integrity of a 15-ppm product.
- Potential migration of sulfur molecules in a 15-ppm environment requiring a significant increase in the volume downgraded at interface.
- Reliability and accuracy of test equipment.
- Potential price spikes or lack of spot availabilities during the transition period.

Tests late in 2005 by the Association of Oil Pipe Lines and the American Petroleum Institute indicated ULSD can pick up as much as 3 ppm of sulfur contamination between the certification tank and pipeline entry, while tank farms and handoffs "continue to contribute 1-2 ppm each."

That study concluded potential contamination points would be identified and managed as pipeline companies gain experience in handling ULSD. But it also said dedicated ULSD infrastructure "should be considered," since "off-spec" distillate could "lock up" the distribution system, affecting gasoline and diesel supply. AOPL said its members are spending an estimated $500 million to minimize contamination (OGJ, May 22, 2006, p. 18).

Jim Scandola, Buckeye's senior manager, transportation, sees the introduction of ULSD as having proceeded smoothly to this point. "The product is being tested and certified by the supplying refineries prior to shipment. There have not been any surprises from my perspective," he told OGJ.

Regarding provisions of designate-and-track that hold the party in possession of off-spec ULSD responsible for its disposition, Scandola said that this is not a problem "as we already hold ourselves accountable for any product contamination or regrade situation for all products in our custody. Our oversight program will be robust enough to recognize these situations and keep the risk of inaccurately representing ULSD as on-spec very low."

Scandola said Buckeye is similarly prepared to handle the 20% limit on product downgrading. "Our experience thus far is that [the restriction] is rather generous. If a facility continues to downgrade up to 20% of their annual volume, they shouldn't be in business.

Colonial Pipeline Co.'s preparations to transport ULSD included installation of new transfer system components, including the 10-in. line shown (Fig. 7; photo from Colonial Pipeline Co.).

At least they will make other carriers the carrier of choice in a competitive environment."

Colonial also reports a positive transition to this point. The company budgeted $60 million to overall ULSD improvements, including more than 300 valves and 4 new tanks (2 in Atlanta, and 2 in Greensboro, NC). The new valves are positive-sealing valves, which minimize any contamination of ULSD by other products (Fig. 4).

Colonial Vice-President Jerry Martin explained that "the extra storage space, combined with changes in how we sequence products in the pipeline, were key improvements. ULSD is bracketed with low-sulfur diesel to further protect ULSD shipments."

Colonial's Phase One improvements committed the company to on-spec shipments as far north and east as Fairfax, Va., according to Martin. "We were able to complete equipment upgrades at Mitchell Junction in rural, central Virginia in time to extend shipments throughout the state, including the Tidewater area [Figs. 5-7]. Test results into Dorsey Junction (central Maryland) were also positive and allowed us to begin scheduling ULSD into that facility, which serves Maryland, including Baltimore."

Colonial is currently studying a second phase, which could mean upgrades from Dorsey as far north as Linden, NJ. "We're carefully studying the [Linden] test results we're seeing so far," said Martin, noting that market demand would also a play a role in the timing of any second round of improvements. Martin said that "we regard shipments all the way to Linden as a matter of when, not if."

Initial indications from California, which completed a California Air Resources Board-mandated transition to ULSD for road use as of Sept. 1, 2006, show no significant supply or price disruption. The current EPA deadline for universal use of ULSD is Dec. 1, 2010.

Cost recovery

The Federal Energy Regulatory Commission in June began issuing orders responding to surcharge tariff filings from pipeline companies designed to recover the costs associated with the transition to ULSD.

In responding to filings from Norco Pipeline Inc., Wood River Pipeline (operated by Koch Pipeline Co. LP), and Buckeye, FERC said that each pipeline must account for all costs and revenues related to ULSD surcharges separately and must footnote amounts attributed to the surcharge invested in carrier plant on p. 212 of its annual Form No. 6 filing and any revenues and expenses attributable to the surcharge on p. 700 of its filing. FERC's goal in requiring the Form No. 6 footnotes is to be able to back out costs associated with the ULSD surcharge when deriving appropriate rate index adjustments in 2011.

Some FERC orders have denied filings. These include denial of Magellan Pipeline Co.'s proposal to distribute ULSD-related costs over its entire system.

SFPP LP's tariff surcharge has been protested by Tesoro Refining and Marketing Co. and others that contend that SFPP has failed to describe costs of additional facilities or services related to the ULSD transition.

Acknowledgment

The author acknowledges the contributions of the AOPL-API ULSD Fuels Team, its Designate & Track Roundtable, and the individual participants in both in writing this article. ✦

Reference

1. "The transition to ultra-low sulfur diesel fuel: Effects on prices and supply," US Energy Information Administration, 2001.

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Correction

In the article "US gas carriers' 2005 net incomes climb; construction costs plummet," by Christopher E. Smith, Table 4 (OGJ, Sept. 11, 2006, p. 53) contained errors. Below is a corrected version of the table. The corresponding data have also been updated in the OGJ Energy Database.

US PIPELINE COSTS, ESTIMATED

Table 4

Size, in.	Location[1]	Length, miles	$ Material	Labor	Misc.[2]	ROW & damages	Total	$/mile
LAND PIPELINES								
6	Delaware	15.00	2,611,164	4,241,290	1,851,011	329,012	9,032,477	602,165
10	California (lat.)	0.63	138,676	791,269	201,498	370,209	1,501,652	2,383,575
10	Delaware (L)	4.00	790,741	1,428,706	533,633	109,129	2,862,209	715,552
10	Delaware (L)	6.10	1,054,508	1,712,829	747,524	132,870	3,647,731	597,989
10	Kentucky	13.75	1,708,500	3,110,000	1,565,500	698,500	7,082,500	515,091
12	Texas (lat., L)	1.80	995,533	374,012	626,885	91,000	2,087,430	1,159,683
12	Kentucky	13.75	1,708,500	3,110,000	1,565,500	698,500	7,082,500	515,091
12	Louisiana	17.50	2,604,378	4,550,588	3,565,151	728,950	11,449,067	654,232
16	Pennsylvania (L)	7.00	1,405,762	2,539,922	948,680	194,007	5,088,371	726,910
16	Pennsylvania (L)	7.80	1,355,797	2,202,208	961,102	170,833	4,689,940	601,274
16	Delaware (L)	9.00	2,121,148	4,308,581	1,491,432	364,572	8,285,733	920,637
16	California (lat.)	46.00	8,588,535	18,733,050	4,408,580	11,917,243	43,647,408	948,857
18	Massachusetts	3.50	1,297,531	4,374,660	4,337,636	3,433,392	13,443,219	3,840,920
20	Virginia (lat.)	32.00	7,460,000	25,494,000	15,309,000	3,172,000	51,435,000	1,607,344
24	Wyoming (lat.)	5.00	2,143,050	2,364,110	1,578,908	158,511	6,244,579	1,248,916
24	Massachusetts	7.80	2,634,014	18,939,233	11,694,204	4,820,119	38,087,570	4,883,022
24	Florida	41.66	8,355,626	24,374,991	19,182,726	2,267,000	54,180,343	1,300,536
24	New York	78.00	29,616,000	31,646,000	55,978,000	6,385,000	123,625,000	1,584,936
24	Georgia	124.97	25,006,878	73,124,973	60,138,175	19,017,263	177,287,289	1,418,639
30	Alabama (lat.)	0.14	185,113	362,010	307,088	15,820	870,031	6,214,507
30	Maine (L)	1.74	2,351,000	5,414,000	3,721,000	332,000	11,818,000	6,791,954
30	Texas	8.70	3,271,523	2,715,800	3,172,275	683,750	9,843,348	1,131,419
30	Georgia	9.85	6,240,000	11,136,507	6,084,340	1,733,375	25,194,222	2,557,789
36	Florida (L)	5.00	3,102,023	2,728,907	4,531,138	855,173	11,217,241	2,243,448
36	Florida (L)	6.00	4,161,785	3,726,797	6,205,534	1,086,024	15,180,140	2,530,023
36	Florida (L)	6.00	4,555,640	3,767,239	5,998,231	1,331,493	15,652,603	2,608,767
36	Florida (L)	6.00	4,742,477	6,001,606	6,135,596	865,103	17,744,782	2,957,464
36	Florida (L)	9.20	6,373,453	6,355,711	8,321,998	1,734,289	22,785,451	2,476,679
36	Ohio (L)	10.27	8,849,866	12,881,908	8,020,237	1,425,509	31,177,520	3,035,786
36	Florida	11.15	11,251,159	36,674,922	40,147,268	1,864,300	89,937,649	8,066,157
36	Pennsylvania	15.20	17,776,009	35,513,863	21,110,434	12,676,250	87,076,556	5,728,721
36	Wyoming	27.10	20,200,000	1,831,000	28,933,200	536,000	51,500,200	1,900,376
42	New Jersey	2.45	3,765,029	12,740,575	4,736,197	1,577,438	22,819,239	9,313,975
42	New Jersey (L)	3.23	3,506,852	9,295,067	4,128,566	1,854,835	18,785,320	5,815,889
42	Pennsylvania (L)	3.41	3,586,224	5,066,922	2,506,129	572,080	11,731,355	3,440,280
42	Pennsylvania (L)	5.25	5,659,232	7,958,642	4,385,889	669,914	18,673,677	3,556,891
42	Wyoming	5.80	5,698,522	2,953,649	2,422,756	289,499	11,364,426	1,959,384
42	Kansas	98.50	96,776,620	50,161,109	41,145,092	4,916,497	192,999,318	1,959,384
42	Colorado	115.20	113,184,433	58,665,581	48,120,959	5,750,056	225,721,029	1,959,384
42	Texas	171.90	144,870,734	147,587,267	48,628,856	14,040,764	355,127,621	2,065,897
42	Missouri	175.70	172,625,911	89,475,197	73,392,818	8,769,833	344,263,759	1,959,384
42	Nebraska	317.50	311,944,944	161,686,824	132,625,041	15,847,591	622,104,400	1,959,384
Total projects—land		**1,450.55**	**$1,056,274,890**	**$902,121,525**	**$691,465,787**	**$134,485,703**	**$2,784,347,905**	**$1,919,512**
Total land—2005 report		1,726.01	$1,321,490,074	$1,396,523,392	$873,002,486	$210,590,889	$3,801,606,841	$2,202,540
OFFSHORE PIPELINES								
24	Louisiana	6.23	7,175,832	8,909,058	5,878,710	0	21,963,600	3,525,457
Total projects—offshore		**6.23**	**$7,175,832**	**$8,909,058**	**$5,878,710**	**$0**	**$21,963,600**	**$3,525,457**
Total offshore—2005 report		91.80	$81,633,800	$266,660,100	$199,004,102	$0	$557,677,902	$6,074,923
TOTAL—ALL PROJECTS		**1,456.78**	**$1,063,450,722**	**$911,030,583**	**$697,344,497**	**$134,485,703**	**$2,806,311,505**	**$1,926,380**
2005—report total, all projects		1,817.81	$1,403,123,874	$1,663,183,492	$1,072,006,588	$220,970,789	$4,359,284,743	$2,398,097

[1]L = loop; lat. = lateral. [2]Generally includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees.

Source: US FERC construction-permit applications, July 1, 2005, to June 30, 2006

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Equipment/Software/Literature

Radar unit handles expanded oil field duties

An expanded Rosemount 3300 Series guided wave radar level and interface transmitter is designed to help users enhance safety and efficiency in extreme environments.

The expansion includes special probes designed to prevent leakage and perform reliably when exposed to high temperature and pressure conditions over extended periods. The 3300 is now available for temperatures as high as 750° F. and pressures as high as 5,000 psig. Common applications with these extreme environments include refinery distillation columns, liquefied gases and freons, power plant utility heater vessels, gas-oil production separators, oil water separators, and compressor tanks.

Materials for the special Rosemount 3300 probes have been selected to avoid stress fractures commonly induced by high pressures and temperatures. The design of the new probes adapts to thermal expansion and contraction, retains strength, and provides efficient feed-through of microwave signals, the company points out.

Source: **Emerson Process Management, Rosemount Div.**, 8200 Market Blvd., Chanhassen, MN 55317.

New temperature calibrators

New JOFRA advanced temperature calibrators (ATC) series combines the accuracy of laboratory temperature sources with the speed and portability of field dry-block calibrators. Units help make it possible to calibrate even more sensors at the same time along with large and odd size sensors in either a large diameter dry block or in a liquid bath.

Calibrators are available in six temperature ranges. All six of the ATC series calibrators feature the dual-zone heating block designed for optimum performance and superior temperature homogeneity throughout the block.

Source: **Ametek Test & Calibration-Americas**, 1220 Washington Ave., Bldg 7A, Suite 300, Albany, NY 12226.

New push-fit tube fitting

The new Phastite tube fitting is assembled via simple push-fit operation, and it provides permanent connections for fluid systems operating at as much as 20,000 psi.

The firm says its fitting can replace cone and thread or welded fittings. Phastite employs a compression assembly principle using a novel form of toothed profile, which makes the seal. The fittings are supplied as one-piece components.

Source: **Parker Instrumentation Products Div.**, 1005 A Cleaner Way, Huntsville, AL 35805-6708.

Services/Suppliers

Ulterra Drilling Technologies

Fort Worth, has named Bob Iversen as president and chief executive officer. Iverson has broad experience in executive and operations management in the upstream oil and gas industry, including 17 years with divisions of Baker Hughes Inc., eight years with Diamond Products International (DPI), and tenure with NQL Energy Services, and most recently with INRG consultancy. He earned a BS degree in petroleum engineering from Montana Tech University.

Ulterra Drilling Technologies, formerly known as RockBit International, manufactures rollercone and polycrystalline diamond compact drill bits. The rebranded company is a leader in MWD horizontal and vertical drilling products and services through its subsidiary, Ulterra MWD.

Schlumberger

Paris, has announced two recent alliances. Schlumberger, Cisco Systems, and Intel will collaborate to develop a first mile wireless service for oil field operations. The first mile in the oil field refers to the critical connectivity of drilling sites or producing fields into a wider network. The new service delivers a collaborative work environment in which geoscientists, petroleum engineers, rig and platform personnel, and other technical and business analysts can access and exploit multiple data sources.

Schlumberger and Infosys have formed a global alliance to provide information management solutions that integrate upstream technical and business processes for oil and gas companies. Primary focus is on integration of E&P petrotechnical data and applications with financial and human resources back-end systems.

Schlumberger is a leading provider of technology, information solutions, and integrated project management to optimize reservoir performance for customers in the oil and gas industry.

Acteon Group Ltd.

Norwich, UK, has launched its newest company, InterMoor do Brasil, as a wholly owned subsidiary based in Rio de Janeiro. The Brazilian company, which is affiliated with Houston-based InterMoor, offers specialized mooring and rig relocation services. John Riggs, who has been with InterMoor for nine years, will serve as managing director for the new company.

Acteon is a group of specialist engineering companies serving the global offshore oil and gas industry, focusing on applications between the seabed and surface production facilities.

Cameron

Houston, has announced a joint venture with Curtiss-Wright Flow Control Corp.'s Electro-Mechanical Div. to supply subsea multiphase pumping systems. The joint venture will operate as Cameron/Curtiss-Wright EMD LLC.

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

Geotrace

Houston, has announced the promotion of Mark Carrigan to vice-president Western Hemisphere, Tigress Software. Carrigan will be responsible for assimilating Tigress into Geotrace and acting as the Geotrace liaison for Tigress integration.

Geotrace is part of the Geotrace Technologies group of companies, and is a leading provider of proprietary technologies used to enhance optimization of petroleum reservoirs

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API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	10-13 2006	[1]10-6 2006	10-13 2006	[1]10-6 2006	10-13 2006	[1]10-6 2006	10-14 2005
	1,000 b/d						
Total motor gasoline	376	506	65	27	441	533	530
Mo. gas. blending comp.	498	489	26	30	524	519	493
Distillate[2]	246	226	57	22	303	248	206
Residual	198	170	21	56	219	226	436
Jet fuel-kerosine	143	43	114	122	257	165	174
LPG	345	354	—	—	345	354	379
Unfinished oils	570	562	74	87	644	649	549
Other	434	265	11	30	445	315	514
Total products	**2,810**	**2,635**	**368**	**374**	**3,178**	**3,009**	**3,281**
Canadian crude	1,687	2,141	117	84	1,804	2,225	1,375
Other foreign	7,853	8,360	1,326	1,119	9,179	9,479	7,279
Total crude	**9,540**	**10,501**	**1,443**	**1,203**	**10,983**	**11,704**	**8,654**
Total imports	**12,350**	**13,136**	**1,811**	**1,577**	**14,161**	**14,713**	**11,935**

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

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*10-13-06	*10-14-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	65.35	76.96	–11.62	–15.1
Brent crude	57.81	58.50	–0.69	–1.2
Crack spread	7.53	18.47	–10.93	–59.2
FUTURES MARKET PRICES				
One month				
Product value	66.28	78.64	–12.36	–15.7
Light sweet crude	58.50	63.03	–4.53	–7.2
Crack spread	7.78	15.61	–7.83	–50.2
Six month				
Product value	76.94	81.01	–4.07	–5.0
Light sweet crude	64.60	63.56	1.04	1.6
Crack spread	12.34	17.45	–5.11	–29.3

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel Kerosine	Fuel oils: Distillate	Fuel oils: Residual	Unfinished oils
	1,000 bbl						
PAD I	16,000	57,574	27,343	11,470	66,531	17,594	9,062
PAD II	67,239	53,555	17,210	7,144	26,808	2,261	15,078
PAD III	181,761	63,003	27,174	12,372	34,803	15,886	43,593
PAD IV	13,568	6,016	1,703	548	2,446	533	3,003
PAD V	[2]55,720	29,057	20,746	9,778	13,833	5,816	20,833
Oct. 13, 2006	**[2]334,288**	**209,205**	**94,176**	**41,312**	**144,421**	**42,090**	**91,574**
Oct. 6, 2006[3]	**326,246**	**215,269**	**97,772**	**41,613**	**146,985**	**43,602**	**91,531**
Oct. 14, 2005	**316,634**	**197,905**	**66,607**	**35,984**	**124,119**	**33,187**	**89,634**

[1]Included in total motor gasoline. [2]Includes 6.645 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—OCT. 13, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	2,595	1,211	1,249	1,618	77.2	1,810	84	450	43
App. Dist. 1	103	95	95	95	100.0	46	—	29	1
Dist. 1 total	**2,698**	**1,306**	**1,344**	**1,713**	**78.5**	**1,856**	**84**	**479**	**44**
Ind., Ill., Ky.	2,171	2,042	2,045	2,355	86.8	1,160	159	565	34
Minn., Wis., Dak.	418	406	407	442	92.1	306	28	109	8
Okla., Kan., Mo.	827	688	691	786	87.9	467	25	226	6
Dist. 2 total	**3,416**	**3,136**	**3,143**	**3,583**	**87.7**	**1,933**	**212**	**900**	**48**
Inland Texas	899	614	627	647	96.9	448	56	173	6
Texas Gulf Coast	4,170	3,595	3,724	4,031	92.4	1,401	321	998	177
La. Gulf Coast	3,365	3,003	3,147	3,264	96.4	1,243	357	796	77
N. La. and Ark.	219	189	191	215	88.8	88	8	44	4
New Mexico	156	109	113	113	100.0	94	—	31	—
Dist. 3 total	**8,809**	**7,510**	**7,802**	**8,270**	**94.3**	**3,274**	**742**	**2,042**	**264**
Dist. 4 total	**618**	**504**	**509**	**596**	**85.4**	**327**	**19**	**165**	**18**
Dist. 5 total	**2,607**	**2,531**	**2,749**	**3,173**	**86.6**	**1,676**	**366**	**496**	**159**
Oct. 13, 2006	**18,348**	**14,987**	**15,547**	**17,335**	**89.7**	**9,066**	**1,423**	**4,082**	**533**
Oct. 6, 2006*	**18,455**	**15,274**	**15,747**	**17,335**	**90.8**	**9,162**	**1,416**	**4,170**	**596**
Oct. 14, 2005	**14,972**	**13,102**	**13,507**	**17,115**	**78.9**	**8,126**	**1,298**	**3,436**	**461**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 10-11-06	Pump price* 10-11-06	Pump price 10-12-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	166.0	209.5	278.8
Baltimore	175.6	217.5	266.4
Boston	186.4	228.3	265.8
Buffalo	166.1	234.0	280.2
Miami	182.3	232.6	278.7
Newark	195.5	228.4	268.5
New York	174.5	242.4	280.4
Norfolk	176.3	214.3	277.0
Philadelphia	182.8	233.5	277.3
Pittsburgh	181.3	232.0	269.7
Wash., DC	198.3	236.7	295.5
PAD I avg.	180.5	228.1	276.2
Chicago	186.6	241.7	276.1
Cleveland	166.8	213.2	256.6
Des Moines	162.1	202.2	248.0
Detroit	171.3	224.2	253.6
Indianapolis	165.2	214.2	251.2
Kansas City	174.2	210.2	244.6
Louisville	170.3	207.2	255.5
Memphis	180.2	220.0	264.2
Milwaukee	176.9	228.2	274.5
Minn.-St. Paul	179.8	220.2	246.5
Oklahoma City	172.8	208.2	241.8
Omaha	174.7	220.1	251.6
St. Louis	180.7	216.7	272.2
Tulsa	169.9	205.3	240.2
Wichita	169.8	213.2	243.3
PAD II avg.	173.4	216.3	254.7
Albuquerque	185.5	221.9	271.2
Birmingham	172.6	211.3	279.2
Dallas-Fort Worth	167.9	206.3	275.2
Houston	171.9	210.3	283.0
Little Rock	174.1	214.3	261.4
New Orleans	187.2	225.6	NA
San Antonio	183.8	222.2	262.7
PAD III avg.	177.5	216.0	272.1
Cheyenne	214.1	246.5	266.5
Denver	211.8	252.2	269.3
Salt Lake City	214.8	257.7	272.4
PAD IV avg.	213.6	252.1	269.4
Los Angeles	200.6	261.2	294.3
Phoenix	205.7	243.1	281.8
Portland	217.9	261.2	260.5
San Diego	204.6	265.2	293.4
San Francisco	215.7	276.3	291.3
Seattle	221.8	271.2	278.8
PAD V avg.	211.1	263.0	283.4
Week's avg.	**184.2**	**228.6**	**261.9**
Sept. avg.	**208.9**	**253.3**	**282.5**
Aug. avg.	**252.4**	**296.7**	**250.2**
2006 to date	**220.3**	**263.9**	—
2005 to date	**180.0**	**222.0**	—

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

REFINED PRODUCT PRICES

	10-6-06 ¢/gal		10-6-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	151.40	New York Harbor	164.25
Gulf Coast	153.40	Gulf Coast	164.50
Los Angeles	166.50	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	139.37	ARA	173.05
Singapore	149.40	Singapore	169.29
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	151.80	New York Harbor	90.55
Gulf Coast	228.05	Gulf Coast	85.71
Los Angeles	174.25	Los Angeles	114.02
		ARA	91.40
		Singapore	106.29

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

BAKER HUGHES RIG COUNT

	10-13-06	10-14-05
Alabama	5	6
Alaska	6	10
Arkansas	26	14
California	33	27
Land	30	23
Offshore	3	4
Colorado	90	86
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	9	7
Kentucky	13	7
Louisiana	194	181
N. Land	57	53
S. Inland waters	18	19
S. Land	43	35
Offshore	76	74
Maryland	1	0
Michigan	1	2
Mississippi	11	8
Montana	17	24
Nebraska	0	0
New Mexico	88	95
New York	8	2
North Dakota	35	25
Ohio	9	9
Oklahoma	178	156
Pennsylvania	15	14
South Dakota	1	4
Texas	799	666
Offshore	14	9
Inland waters	6	2
Dist. 1	20	13
Dist. 2	28	41
Dist. 3	53	61
Dist. 4	97	71
Dist. 5	134	112
Dist. 6	120	102
Dist. 7B	45	18
Dist. 7C	40	37
Dist. 8	96	75
Dist. 8A	27	24
Dist. 9	44	35
Dist. 10	75	66
Utah	45	25
West Virginia	30	25
Wyoming	107	82
Others—HI-1; ID-1; NV-2; OR-1;TN-1; WA-1	7	5
Total US	**1,728**	**1,482**
Total Canada	**477**	**534**
Grand total	**2,205**	**2,016**
Oil rigs	310	215
Gas rigs	1,422	1,262
Total offshore	95	88
Total cum. avg. YTD	**1,630**	**1,358**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	10-13-06 Percent footage*	Rig count	10-14-05 Percent footage*
0-2,500	52	—	27	—
2,501-5,000	93	47.3	66	34.8
5,001-7,500	244	18.4	151	20.5
7,501-10,000	402	3.4	326	5.5
10,001-12,500	415	2.1	330	2.1
12,501-15,000	268	0.3	287	0.3
15,001-17,500	119	—	118	—
17,501-20,000	71	—	51	—
20,001-over	35	—	18	—
Total	**1,699**	**6.6**	**1,374**	**5.8**
INLAND	41		35	
LAND	1,593		1,293	
OFFSHORE	65		46	

*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]10-13-06	[2]10-14-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	759	839
California	701	697
Colorado	58	57
Florida	7	7
Illinois	29	29
Kansas	93	92
Louisiana	1,367	592
Michigan	15	17
Mississippi	51	45
Montana	92	96
New Mexico	164	163
North Dakota	103	101
Oklahoma	173	171
Texas	1,354	1,172
Utah	45	47
Wyoming	140	143
All others	68	75
Total	**5,237**	**4,364**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	10-6-06
Alaska-North Slope 27°	66.06
South Louisiana Sweet	54.25
California-Kern River 13°	46.75
Lost Hills 30°	54.20
Southwest Wyoming Sweet	58.82
East Texas Sweet	57.15
West Texas Sour 34°	46.50
West Texas Intermediate	55.25
Oklahoma Sweet	55.25
Texas Upper Gulf Coast	52.00
Michigan Sour	48.25
Kansas Common	54.25
North Dakota Sweet	45.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	10-6-06
United Kingdom-Brent 38°	57.89
Russia-Urals 32°	57.22
Saudi Light 34°	54.71
Dubai Fateh 32°	57.13
Algeria Saharan 44°	59.55
Nigeria-Bonny Light 37°	60.42
Indonesia-Minas 34°	58.40
Venezuela-Tia Juana Light 31°	54.00
Mexico-Isthmus 33°	53.89
OPEC basket	56.87
Total OPEC[2]	55.73
Total non-OPEC[2]	54.36
Total world[2]	54.92
US imports[3]	52.75

[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]

	10-6-06	9-29-06	Change
	Bcf		
Producing region	979	965	14
Consuming region east	1,951	1,914	37
Consuming region west	459	448	11
Total US	**3,389**	**3,327**	**62**
	July 06	**July 05**	**Change, %**
Total US[2]	**2,779**	**2,450**	**13.4**

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

Statistics

World oil balance

	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.	2005 2nd qtr.	2005 1st qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	20.88	20.76	21.07	21.09	20.88	20.98
Canada	2.16	2.18	2.23	2.24	2.24	2.36
Mexico	2.01	2.08	2.10	2.06	2.11	2.04
Japan	4.78	5.96	5.46	5.03	4.94	6.00
South Korea	2.03	2.28	2.23	2.01	2.07	2.40
France	1.89	2.10	1.96	2.00	1.93	2.11
Italy	1.63	1.86	1.78	1.68	1.69	1.77
United Kingdom	1.83	1.85	1.81	1.81	1.77	1.83
Germany	2.55	2.56	2.63	2.75	2.55	2.54
Other OECD Europe	7.14	7.35	7.45	7.31	7.21	7.33
Australia & New Zealand	1.06	1.07	1.10	1.04	1.06	1.04
Total OECD	**47.96**	**50.05**	**49.82**	**49.02**	**48.45**	**50.40**
NON-OECD						
China	7.34	7.15	7.14	6.93	6.89	6.62
FSU	3.90	4.40	4.60	4.04	3.81	4.30
Non-OECD Europe	0.69	0.74	0.69	0.64	0.69	0.74
Other Asia	8.81	8.43	9.06	8.43	8.71	8.34
Other non-OECD	14.47	14.41	14.14	14.14	13.91	13.84
Total non-OECD	**35.21**	**35.13**	**35.63**	**34.18**	**34.01**	**33.84**
TOTAL DEMAND	**83.17**	**85.18**	**85.45**	**83.20**	**82.48**	**84.24**
SUPPLY						
OECD						
US	8.35	8.18	7.56	7.93	8.80	8.72
Canada	3.13	3.22	3.28	3.02	3.06	3.01
Mexico	3.79	3.80	3.75	3.72	3.89	3.77
North Sea	4.71	5.13	5.05	4.95	5.22	5.46
Other OECD	1.44	1.44	1.51	1.55	1.57	1.49
Total OECD	**21.42**	**21.77**	**21.15**	**21.17**	**22.54**	**22.45**
NON-OECD						
FSU	11.98	11.76	11.97	11.72	11.62	11.53
China	3.85	3.83	3.75	3.80	3.76	3.73
Other non-OECD	12.98	12.98	13.26	13.03	12.59	12.41
Total non-OECD, non-OPEC	**28.81**	**28.57**	**28.98**	**28.55**	**27.97**	**27.67**
OPEC	**33.76**	**33.84**	**34.23**	**34.48**	**34.18**	**33.99**
TOTAL SUPPLY	**83.99**	**84.18**	**84.36**	**84.20**	**84.69**	**84.11**
Stock change	**0.82**	**–1.00**	**–1.09**	**1.00**	**2.23**	**–0.13**

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

US petroleum imports from source country

	July 2006	June 2006	Average YTD 2006	Average YTD 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	743	740	606	467	139	29.8
Kuwait	155	201	165	206	–41	–19.9
Nigeria	1,073	1,094	1,171	1,131	40	3.5
Saudi Arabia	1,313	1,522	1,442	1,597	–155	–9.7
Venezuela	1,467	1,306	1,455	1,590	–135	–8.5
Other OPEC	754	786	664	629	35	5.6
Total OPEC	**5,505**	**5,649**	**5,503**	**5,620**	**–117**	**–2.1**
Angola	695	565	501	406	95	23.4
Canada	2,114	2,258	2,250	2,121	129	6.1
Mexico	1,709	1,855	1,784	1,648	136	8.3
Norway	236	140	199	242	–43	–17.8
United Kingdom	340	355	294	376	–82	–21.8
Virgin Islands	353	273	305	326	–21	–6.4
Other non-OPEC	2,885	3,050	2,788	2,680	108	4.0
Total non-OPEC	**8,332**	**8,496**	**8,121**	**7,799**	**322**	**4.1**
TOTAL IMPORTS	**13,887**	**14,145**	**13,624**	**13,419**	**205**	**1.5**

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

OECD total net oil imports

	June 2006	May 2006	Apr. 2005	June 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–978	–1,196	–1,157	–927	–51	5.5
US	12,801	12,862	11,951	12,785	16	0.1
Mexico	–1,677	–1,761	–1,682	–1,704	27	–1.6
France	1,746	1,762	1,772	1,383	363	26.2
Germany	2,465	2,358	2,349	2,245	220	9.8
Italy	1,536	1,379	1,436	1,568	–32	–2.0
Netherlands	1,152	868	934	942	210	22.3
Spain	1,521	1,457	1,558	1,550	–29	–1.9
Other importers	3,860	3,883	3,638	3,708	152	4.1
Norway	–2,836	–2,326	–2,511	–2,450	–386	15.8
United Kingdom	44	240	122	–194	238	–122.7
Total OECD Europe	**9,488**	**9,621**	**9,298**	**8,752**	**736**	**8.4**
Japan	4,443	4,970	5,123	5,183	–740	–14.3
South Korea	2,128	2,374	2,271	1,848	280	15.2
Other OECD	1,065	1,117	938	911	154	16.9
Total OECD	**27,270**	**27,987**	**26,742**	**26,848**	**422**	**1.6**

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

OECD* total gross imports from OPEC

	June 2006	May 2006	Apr. 2005	June 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	435	245	391	369	66	17.9
US	5,649	5,782	5,477	5,798	–149	–2.6
Mexico	5	10	—	—	5	—
France	916	779	782	633	283	44.7
Germany	522	494	504	435	87	20.0
Italy	1,246	985	1,071	1,109	137	12.4
Netherlands	652	517	540	663	–11	–1.7
Spain	807	674	783	625	182	29.1
Other importers	1,391	1,093	1,269	1,115	276	24.8
United Kingdom	253	267	188	235	18	7.7
Total OECD Europe	**5,787**	**4,809**	**5,137**	**4,815**	**972**	**20.2**
Japan	4,007	4,277	4,799	4,286	–279	–6.5
South Korea	2,273	2,469	2,294	1,829	444	24.3
Other OECD	678	745	544	681	–3	–0.4
Total OECD	**18,834**	**18,337**	**18,642**	**17,778**	**1,056**	**5.9**

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

Oil stocks in OECD countries*

	June 2006	May 2005	Apr. 2005	June 2005	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	189	194	196	186	3	1.6
Germany	281	280	282	279	2	0.7
Italy	126	130	132	132	–6	–4.5
United Kingdom	101	105	103	102	–1	–1.0
Other OECD Europe	654	655	649	631	23	3.6
Total OECD Europe	**1,351**	**1,364**	**1,362**	**1,330**	**21**	**1.6**
Canada	166	168	169	165	1	0.6
US	1,730	1,724	1,701	1,738	–8	–0.5
Japan	627	634	618	629	–2	–0.3
South Korea	155	152	144	142	13	9.2
Other OECD	106	106	107	108	–2	–1.9
Total OECD	**4,135**	**4,148**	**4,101**	**4,112**	**23**	**0.6**

*End of period.
Source: DOE International Petroleum Monthly Report.
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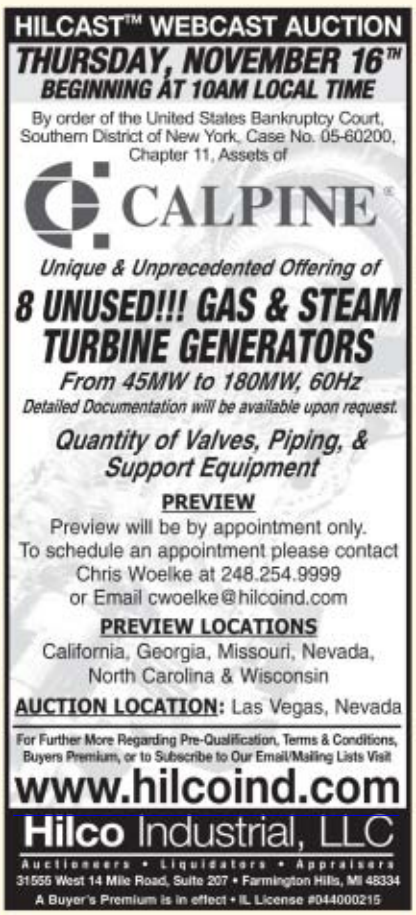

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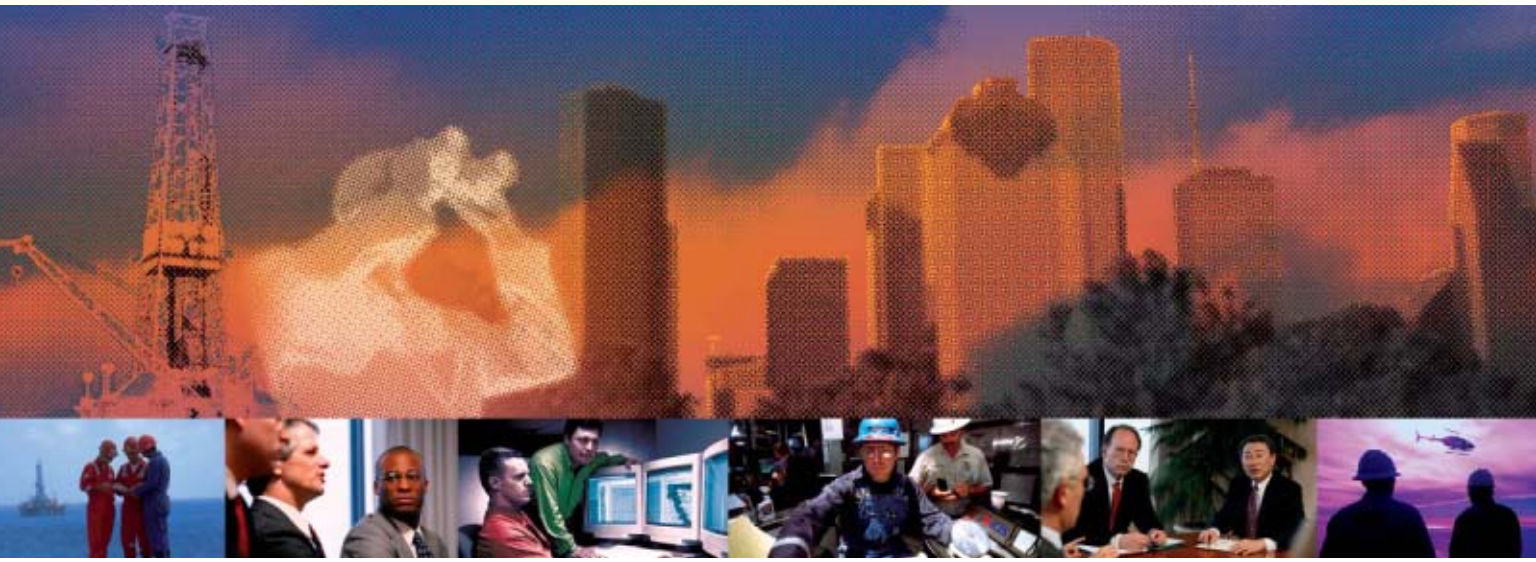

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Shtokman surprise a reminder of BTC pipeline rebuke

Russia's Oct. 9 turnabout on development of Shtokman gas and condensate field in the Barents Sea shows that the sword of pipeline politics has two edges.

Instead of taking aboard international partners for the world-class project, OAO Gazprom said it would work solo.

The decision fell hard on the five short-listed companies that had competed for what were to have been two minority

The Editor's Perspective

by Bob Tippee, Editor

interests in the project (OGJ Online, Oct. 10, 2006).

It also diverted Shtokman gas away from the US. Gazprom said it would base development on a pipeline to Germany instead of an US-oriented LNG scheme.

Gazprom attributed this new Russian elbow into the ribs of international investment to economics, not least the uncertainty of LNG sales in comparison with pipeline deliveries secured by long-term contract. The move surely will help Russia reestablish its supply-security credentials after scaring European customers last winter by cutting deliveries to Ukraine.

It also may represent exasperation over Washington's resistance to Moscow's entry into the World Trade Organization.

Long forgotten in the eminently forgetful US is the rebuke to Russia embodied in the Batumi-Tibilisi-Ceyhan crude oil line between Azerbaijan and Turkey by way of Georgia.

That 1,040-mile, $4 billion marvel, operated by a BP group, started up last May. It is supposed to transport 500,000 b/d by the end of the year and can carry twice that much.

There were shorter and cheaper routes for Azeri output. But they would have transited Armenia, with which Azerbaijan lives in perpetual hostility, or Iran, with which the US has longstanding quarrels.

Another pipeline through Russia might also have been an option. But it would have increased tanker traffic through the Bosporus Strait over the objection of Turkey, which anyway stood to profit from the BTC project.

So the US strongly supported—some might say pushed—the BTC pipeline. And the justification's short version always had little to do with Turkey and much to do with avoiding Iran and Russia.

It's probably too much to read BTC comeuppance into the Shtokman stunner. But it's useful to remember that nobody's above playing politics with pipelines.

(Online Oct. 13, 2006; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

OPEC calls emergency meeting

After weeks of falling crude prices, the Organization of Petroleum Exporting Countries finally agreed to an emergency meeting Oct. 19 in Qatar to discuss a possible production cut of 1 million b/d.

Analysts in the Houston office of Raymond James & Associates Inc. said the group would try to work out details of what would be its first official production cut since April 2004. Ministers had been debating whether the cut would be from actual output of about 27.5 million b/d for members other than Iraq or from the "notional" group quota of 28 million b/d. "The results of the meeting should help shrug off the uncertainties related to the cut that have been hanging over the market in the last couple of weeks," the Raymond James analysts said.

The US Energy Information Administration (EIA) estimates the 10 OPEC members subject to quota are producing 27.6 million b/d of crude.

However, Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va., said, "OPEC (including Iraq) produced 29.8 million b/d of crude oil in September and needs to produce 29.5 million b/d in the fourth quarter of 2006 and 29 million b/d in the first quarter of 2007 to balance global supply-demand." He said, "OPEC really does not need to remove supply from the market until the first quarter. However, we think it will occur before that due to the recent crude oil price decline."

Because of the gap between OPEC's official quota and its actual production, the "only practical solution" would be a uniform 3.5% reduction for each member based on September production levels, said analysts with the Société Générale (SG) group.

"We do not think this [reduction] will have much impact on the market. At best, OPEC can expect the market to give it some short-term credit by trading in a narrow range (say $57-62/bbl) until it gets the first indications on compliance," they said.

"The oil market is indeed oversupplied (by only 500,000 b/d)," said SG analysts. But that oversupply "would have disappeared mechanically" in the fourth quarter, "even with OPEC still producing at the current level," they said. "The market has been oversupplied on average for the last 3 years without having any downward impact on the price. Therefore, strictly speaking, the market is not looking for a rebalancing of supply as it knows the bearish trend is not fueled by any physical issue but rather for the degree of OPEC's commitment to floor the price at a certain level."

Other market factors

After a steep fall earlier in the week, crude futures prices rallied Oct. 12-13 from a 10-month low, buoyed by reports of the first decline in US distillate inventories since early August. The November contract for benchmark US light, sweet crudes hit a 2006 low of $57.22/bbl in overnight electronic trading Oct. 12 on the New York Mercantile Exchange but rallied to close at $57.86/bbl. It finished the week at $58.57/bbl Oct. 13.

In the interim, safety authorities in Norway ordered production shut down at two offshore platforms operated by Statoil ASA and Royal Dutch Shell PLC, reportedly over concerns about lifeboat standards. That has reduced Norwegian production by 280,000 b/d from 2.7 million b/d of crude oil and natural gas liquids.

Crude markets also were buoyed by unseasonably cold weather in the northeastern US (OGJ Online, Oct. 12, 2006). Nonetheless, crude futures prices ended the week 2% lower Oct. 13.

Energy supplies

US distillate fuel inventories dropped 1.6 million bbl to 149.9 million bbl during the week ended Oct. 6. Ultralow-sulfur diesel dipped by 200,000 bbl in its first decline since the week ended July 14. Heating oil fell by 1.8 million bbl, the largest decline since the week ended Mar. 24, said EIA officials.

The November natural gas contract fell 36.8¢ to $5.78/MMbtu Oct. 12 and was down to $5.66/MMbtu Oct. 13 on NYMEX as US winter gas storage increased to the highest level ever. EIA reported the injection of 62 bcf of gas during the week ended Oct. 6, boosting US storage to nearly 3.4 tcf, up by 410 bcf from year-ago levels and 358 bcf above the 5-year average.

Natural gas futures prices were higher in early trading Oct. 16 after Northeast US weather turned colder than expected. A state of emergency was declared in Buffalo, NY, where 2 ft of snow triggered power outages. The November natural gas contract fell Oct. 11-13, ending an 8-day rally and finishing the week at $5.66/MMbtu on NYMEX.

(Online Oct. 16, 2006; author's e-mail: samf@ogjonline.com)

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