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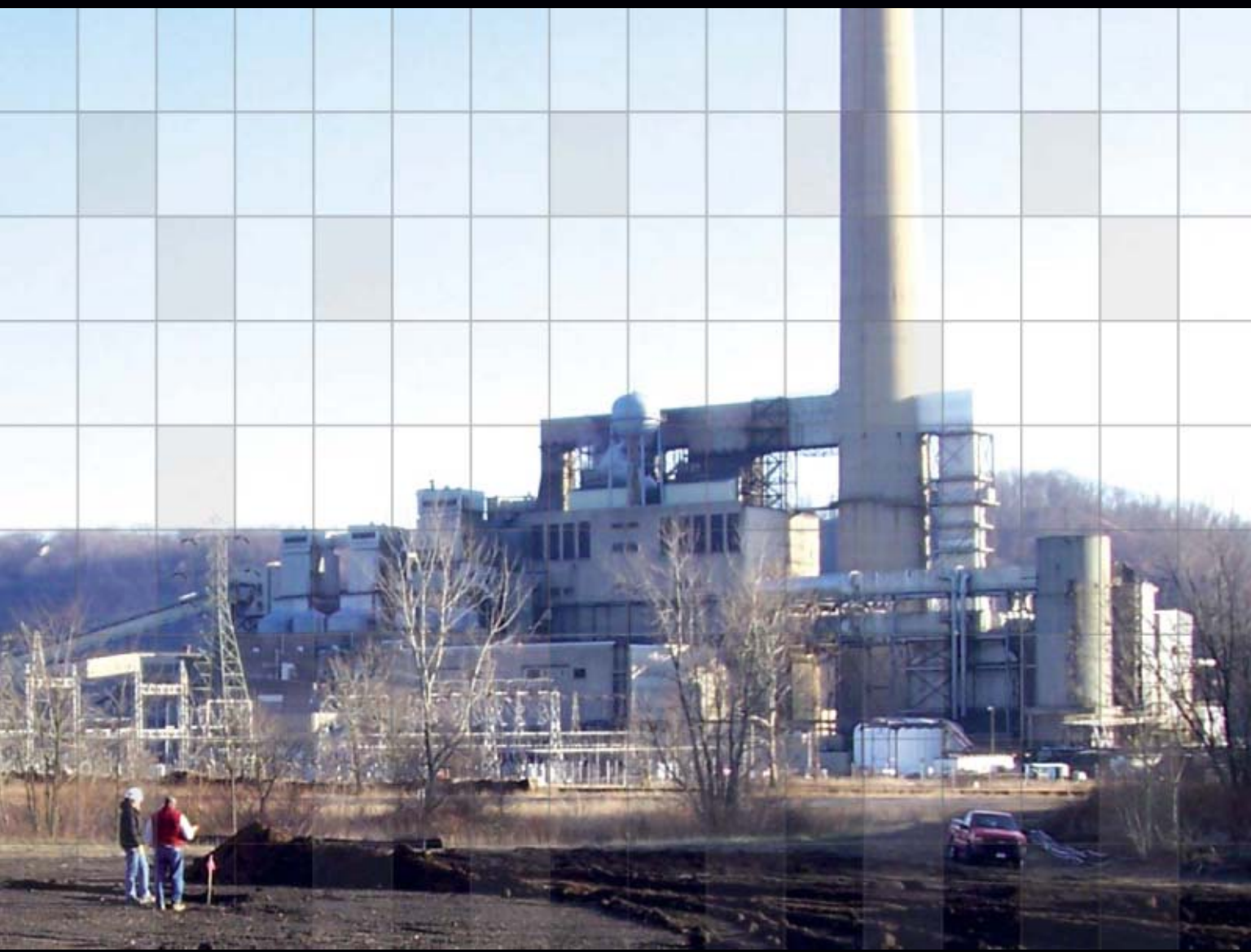

Managing CO_2

Insurance statistical analysis provided for marine E&D
Floating production expanding rapidly
Study outlines European refinery demand to 2015
Model studies thermal effects of liquid pipeline colocation

OIL&GAS JOURNAL®

May 14, 2007
Volume 105.18

MANAGING CO_2

REGULAR FEATURES

COVER

Scientists from industry, government, and universities are studying the potential for geologic sequestration of CO_2 emitted by industrial plants. A special report article, starting on p. 20, discusses some of the research being done under a US Department of Energy program. The cover photo shows Battelle scientists preparing to drill an 8,000 ft test well at FirstEnergy's R.E. Burger plant to evaluate CO_2 storage potential in the Appalachian basin. Drilling was completed in February. Battelle is the lead organization for the Midwest Regional Carbon Sequestration Partnership. The drilling rig shown on the top of this page is AEP's Mountaineer Plant in West Virginia. Under a separate DOE-funded initiative, Battelle scientists also drilled the first test well at a coal-fired plant to determine CO_2 storage potential in the Camrian rocks in the Appalachian basin. Photos from Battelle.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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May 14, 2007

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General Interest — Quick Takes

Improve UK North Sea safety standards, BP told

The UK Health and Safety Executive (HSE) has ordered BP PLC to carry out a major audit of its safety practices for operations at its platforms in the UK North Sea, raising fresh fears about the company's safety culture.

HSE in March served BP with an improvement notice that required it to improve its operations and show that it is meeting health and safety regulations after a series of safety concerns on the Schiehallion floating production and storage facility, 150 miles west of Shetland. Within the past year, BP received 14 safety standards notices, and it has complied with 10 of them.

UK unions for oil and gas workers were unsurprised at the news, stressing that they have been campaigning for an improved safety culture in the UK North Sea for some time and that investment is needed to maintain oil and gas infrastructure, particularly as energy prices currently are so high.

HSE said over the past year it has served 51 improvement notices and nine prohibition notices on various platforms and other companies in the UK sector of the North Sea.

The HSE notices for BP, however, come amid a company-wide review of its operations following harsh criticisms of its safety practices in the Baker report published earlier this year, which examined the Texas City, Tex., refinery fire that killed 15 people in March 2005. Last year BP also was forced to close in oil production from its Alaska Prudhoe Bay field because of pipeline corrosion.

BP has appointed independent expert Duane Wilson, a retired ConocoPhillips vice-president for refining and marketing, to lead its safety improvements in wake of the Baker report.

Tony Hayward, BP's new chief executive, who took over the company earlier this month, is expected to make safety an important part of his agenda in the early part of his tenure.

MMS Director Johnnie Burton to retire

US Minerals Management Service Director Johnnie Burton announced that she will retire at the end of May.

Burton, who became MMS director in March 2002, told Department of the Interior Sec. Dirk A. Kempthorne in her May 7 resignation letter that the job "has been the most rewarding, and often the most challenging, of my career."

Her successor has not been named. Burton will be the second US DOI agency chief involved with federal oil and gas resource management to leave in the last year.

US Bureau of Land Management Director Kathleen Clarke resigned on Dec. 28, 2006, to rejoin her family in Utah.

Burton's primary accomplishment as MMS director was completion of a 5-year federal Outer Continental Shelf leasing plan from July 1, 2007, through June 30, 2012, that includes new acreage in the eastern Gulf of Mexico, in the Bristol Bay area off Alaska's coast, and in the Atlantic Ocean off southeastern Virginia.

She also presided over 16 OCS sales and initiated royalty compliance program reforms to make it more effective and eliminate delays.

Burton was criticized when it was discovered that federal Gulf of Mexico deepwater leases issued by MMS in 1998 and 1999 did not contain price thresholds on their royalty exemptions.

Pointing out to angry members of Congress that the omissions took place during the Clinton administration, Burton ordered MMS to approach leaseholders and ask them to voluntarily negotiate new terms. Several leaseholders have done this, and talks with others are continuing.

Attacks on Nigeria oil workers continue

Some 12 foreign oil workers have been abducted in Nigeria in several separate overnight attacks, according to local government and company officials. The latest attacks followed one on May 1 in which armed militants killed one man and took six others hostage.

The most recent attacks, for which no group has claimed responsibility, include an unemployed Dutch oil worker kidnapped from a bar in the southern town of Warri, three South Korean executives and eight Filipino workers seized from a Daewoo construction site in Rivers state after a gunfight, and five people taken from Eni's Mystras floating production, storage, and offloading vessel.

On May 2, Chevron Corp. shut down 15,000 b/d of oil production in Nigeria after a Nigerian sailor was killed and six foreign oil workers kidnapped by members of the militant group Movement for the Emancipation of the Niger Delta. The militants attacked Chevron's Oloibiri FPSO off southern Bayelsa State on May 1 (OGJ Online, May 2, 2007).

Japan to greatly increase products exports

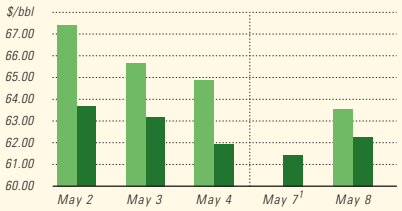
Japan will increase exports of petroleum products by as much as 50% this year due to a decline—for the fourth year running—in domestic demand for fuel oil. The demand drop was caused by the increased use of natural gas by industry, as well as sales of hybrid-electric cars and other low-consumption products.

Nippon Oil Corp. will try to double its petroleum exports to 2.35 million kl, as well as increase contract production for a major Chinese oil firm by 20% to 2.2 million kl. That will give Nippon overall exports of 4.55 million kl, a 50% increase. Cosmo Oil Co. plans to raise its exports by 40% to 1.44 million kl/year, largely by selling jet fuel and diesel in the US market.

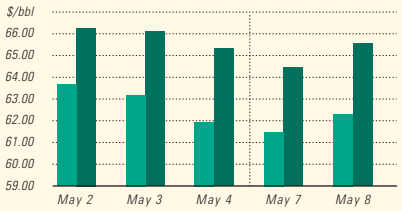
Meanwhile, Taiyo Oil Co. and other midsize oil distributors reportedly will upgrade or create export facilities to step up their overseas shipments. Taiyo will upgrade the ship-loading pumps at

Industry Scoreboard

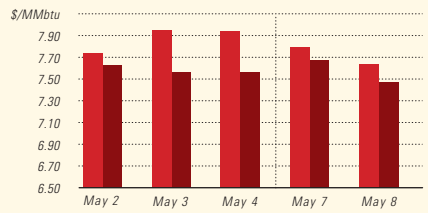
IPE BRENT / NYMEX LIGHT SWEET CRUDE



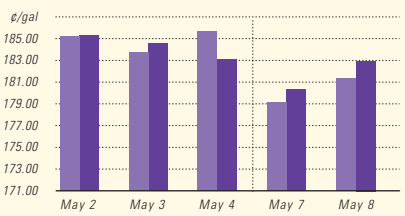
WTI CUSHING / BRENT SPOT



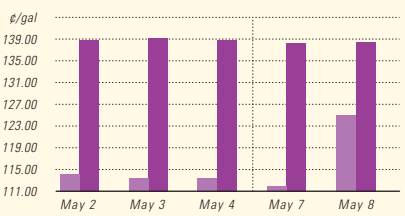
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



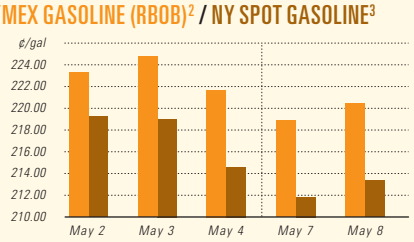
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

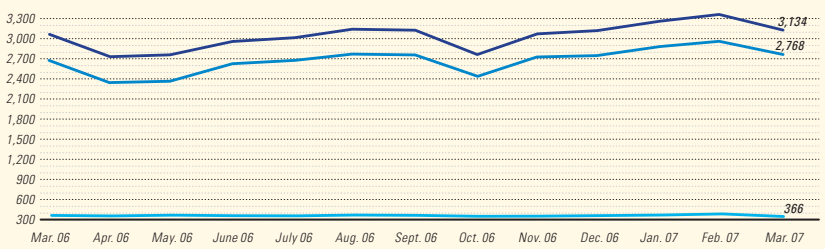
US INDUSTRY SCOREBOARD — 5/14

Latest week 5/4	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,164	9,164	—	9,120	9,029	1.0
Distillate	4,286	4,068	5.4	4,393	4,218	4.1
Jet fuel	1,588	1,646	–3.5	1,608	1,585	1.5
Residual	776	670	15.8	761	749	1.5
Other products	4,867	4,674	4.1	4,973	4,772	4.2
TOTAL DEMAND	20,681	20,222	2.3	20,855	20,353	2.5
Supply, 1,000 b/d						
Crude production	5,139	5,072	1.3	5,254	5,056	3.9
NGL production[2]	2,379	2,285	4.1	2,414	2,168	11.3
Crude imports	10,191	9,859	3.4	9,778	9,890	–1.1
Product imports	3,358	3,592	–6.5	3,180	3,573	–11.0
Other supply[3]	1,077	1,154	–6.7	959	1,102	–13.0
TOTAL SUPPLY	22,144	21,963	0.8	21,585	21,788	–0.9
Refining, 1,000 b/d						
Crude runs to stills	14,853	15,020	–1.1	14,665	14,890	–1.5
Input to crude stills	15,289	15,394	–0.7	15,103	15,231	–0.8
% utilization	88.2	88.5	—	87.1	87.7	—

Latest week 5/4	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	344,778	343,807	971	347,962	–3,184	–0.9
Motor gasoline	199,230	198,293	937	207,449	–8,219	–4.0
Distillate	119,052	119,678	–626	116,459	2,593	2.2
Jet fuel	39,685	39,644	41	41,605	–1,920	–4.6
Residual	38,779	39,466	–687	41,325	–2,546	–6.2
Stock cover (days)[4] **4/27**			**Change, %**		**Change, %**	
Crude	22.1	22.1	—	23.3	–5.2	
Motor gasoline	20.8	20.8	—	22.2	–6.3	
Distillate	27.1	27.2	–0.4	28.0	–3.2	
Propane	27.1	23.0	17.8	35.0	–22.6	
Futures prices[5] **5/4**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	63.30	65.49	–2.19	72.14	–8.84	–12.3
Natural gas, $/MMbtu	7.84	7.64	0.20	6.75	1.09	16.1

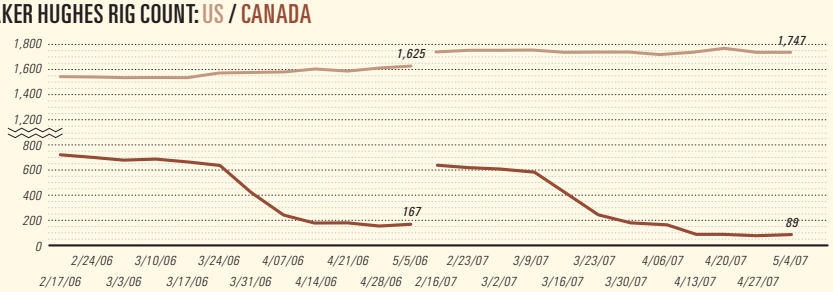
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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its port facilities, while Mitsui Oil & Gas Co. will set up facilities to begin shipping jet fuel by June.

Last December, Taiyo, which refines petroleum products from light crude, announced plans to spend ¥50 billion to install cracking equipment for heavy oil at its Ehime Prefecture refinery (OGJ Online, Dec. 4, 2006).

In January Nippon and South Korean refiner SK Corp. said they would form a 10-year capital and business alliance under which each firm will spend ¥12 billion to purchase an initial 1% stake in the other (OGJ Online, Jan. 23, 2007). ✦

Exploration & Development — *Quick Takes*

Premier rig to work over, drill Anoa field wells

Premier Oil PLC, after plugging and abandoning its Gajah Sumatera-1 exploration well on Natuna Sea Block A in Indonesia, is moving the Seadrill-5 rig to Anoa field to carry out a workover on an existing well. It will then drill a development well to exploit oil discovered last year in Anoa's Central Lobe.

Last September, the company drilled an appraisal well into a new fault block on Anoa field and found a 67 ft column with an overlying 80 ft gas column that it said could greatly increase oil production.

Premier Chief Executive Simon Lockett said, "The Seadrill-5 now moves on to development activity to support existing gas sales contracts into Singapore and to exploit the oil discovered in 2006 in the Central Lobe of Anoa."

The abandoned Gajah Sumatera-1 exploration well drilled a structure adjacent to Gajah Puteri field, reaching a TD of 2,387 m. It had "some gas shows," Premier said, but no significant hydrocarbons.

OGDC finds gas, condensate in Pakistan

Oil & Gas Development Co. Ltd. (OGDC) has found gas and condensate in its exploratory well Kunnar West No. 1A in the Kunnar mining lease area in Pakistan.

The well reached a TD of 4,065 m targeting two zones of Massive Sands of the Cretaceous Lower Goru formation. The first tested 11.02 MMcfd of gas and 170 b/d of 44° gravity condensate through a $^{32}/_{64}$-in. choke.

The well is 577 m west of Kunnar West Well No. 1.

"The potential of additional Zone-2 (Massive Sand) of Lower Goru formation in the well will be tested shortly," OGDC said.

Putumayo well gauges natural oil flows

Gran Tierra Energy Inc., Calgary, gauged natural oil flows on tests of the Cretaceous Lower and Middle Caballos formations at its Juanambu-1 exploration well on the Guayuyaco Block in the Putumayo basin of southern Colombia.

Four more zones were to be tested, including shallower Cretaceous Villeta T sand, the well's primary objective.

The Caballos tests yielded stabilized flows of 32° gravity oil with constant wellhead flowing pressure. Further details were to be released on completion of the remaining tests. Most wells in the basin require pumping.

Working interests are Gran Tierra 50% and Solana Resources Ltd. 50%. State Ecopetrol has a 30% back-in right, which would reduce the companies' respective interests to 35% each.

BowLeven respuds D-1 wildcat off Cameroon

BowLeven PLC, Edinburgh, has respudded its D-1 exploration well on Block MLHP 5 off Cameroon because of mechanical and well-control problems at the first location.

The well is to reach 10,000 ft TD in 8 weeks to target Upper Miocene channelized turbidite sands that could be similar to hydrocarbon-bearing formations found by Noble Energy 10 km downdip in the 0-1 Belinda discovery in Equatorial Guinea (OGJ Online, July 7, 2006).

The original D-1 location was 37 km from a power plant at Limbe, which is proposed as a hub for gas exports to Equatorial Guinea and its LNG plant under construction on Bioko Island (OGJ Online, Feb. 19, 2007).

BowLeven has a 100% interest in Cameroon's Etinde permit area, which holds three shallow-water blocks: MLHP 5, MLHP 6, and MLHP 7. They cover 2,300 sq km in the Rio del Rey and Douala basins.

Centrica awarded stake in Block 2AB off Trinidad

Centrica PLC, parent of British Gas, said the Trinidad and Tobago Energy Ministry has awarded it a share of an offshore license as part of its bid in the Trinidad and Tobago onshore and shallow water bid rounds.

Centrica will have a 32.5% interest in offshore Block 2AB near the Trinidad and Tobago coast and existing LNG export facilities.

Centrica will partner with Tullow Oil PLC, operator and holder of a 32.5% stake in the license, and with state-owned Petrotrin 35%.

Trinidad and Tobago is one of the largest exporters of LNG in the Atlantic Basin, currently accounting for about 80% of LNG imported into the US, said Centrica.

PNG offshore licensing round draws one bid

Just one application has been received for the much-heralded offshore Papua New Guinea licensing round (OGJ Online, Sept. 22, 2006).

The apparent interest from 15 groups that bought bid packages last year for blocks in the Gulf of Papua, Papuan Plateau, Moresby Trough, and parts of the Coral Sea seems to have evaporated.

PNG authorities said they will process the lone application and reserve the other blocks for competitive application and appropriate work program bids at any time. ✦

Drilling & Production — *Quick Takes*

Talisman appraisal well off Vietnam successful

Talisman (Vietnam 15-2/01) Ltd. has drilled a sidetrack appraisal well into its Hai Su Trang (HST) discovery made earlier this year on Block 15-2/01 in the Cuu Long basin off eastern Vietnam.

The sidetrack penetrated the HST structure about 1.1 km northeast of the original discovery location. It was drilled to a TMD of 3,342 m and encountered 51 m of net oil pay at a structural elevation similar to that of the discovery well.

Downhole well logging and sampling confirmed the presence and quality of the same oil-bearing zones tested in the original HST discovery well. As a result, Talisman and its partner, PetroVietnam Exploration & Production Co., anticipate moving quickly to full field development.

Talisman Pres. and Chief Executive Jim Buckee said the HST appraisal well also encountered new zones structurally higher in the section.

Thang Long Joint Operating Co. (TLJOC), a special purpose company established for conducting all operations on Block 15-2/01, plans to begin drilling three new exploration wells in third quarter to evaluate a very exciting basement structure. The company also expects to drill on two more of the many Miocene-Oligocene clastic prospects that are on trend with the HST discovery. Additional exploration drilling is anticipated beyond 2007, Talisman said.

TLJOC is preparing a reserves assessment report for a joint area project development plan. Talisman said discussions will be ongoing with the operators of the Te Giac Trang (TGT) discovery on adjacent Block 16-1. Talisman recently completed a successful sidetrack into the TGT Block 16-1 structure to determine how much it extends into Block 15-2/01 (OGJ Online, Jan. 18, 2007).

Statoil shuts in Kvitebjørn gas, condensate

Statoil ASA is shutting in gas and condensate production from Kvitebjørn field in the Norwegian North Sea because of low pressure in the reservoir during the company's complex drilling program.

A Statoil spokesman told OGJ the company had produced the field at about 50% of its 190,000 boe/d capacity since late December.

"The operation's complexity and adaptation of necessary new technology has led to an extension of the drilling program and resulted in further pressure fall in the reservoir," Statoil said.

Statoil plans to restart production during the fourth quarter.

Statoil is operator of the license with 43.55% interest; other partners are Petoro AS 30%, Norsk Hydro AS 15%, Royal Dutch Shell PLC 6.45%, and Total SA 5%.

Umuroa FPSO on site off New Zealand

The floating production, storage, and offloading vessel for the $245 million Tui oil development has arrived on location on the PMP 38158 permit 50 km off Taranaki on New Zealand's North Island.

The Umuroa FPSO, owned by Prosafe of Norway, is being leased for an initial 5 years to the Tui joint venture, operated by Australian Worldwide Exploration Ltd. of Sydney. The group has an option to retain the vessel for a further 5 years.

Umuroa is capable of handling up to 120,000 b/d of fluids, including 50,000 b/d of oil from the Tui project. It has a storage capacity of 730,000 bbl.

Oil is expected on stream at the end of June from Tui, Amokura, and Pateke accumulations. Flow will be via four subsea wellheads and flowlines connected to the FPSO.

Permit interest holders are AWE 42.5%, New Zealand Oil & Gas Ltd. 12.5%, Mitsui E&P New Zealand 35%, and Pan Pacific Petroleum Ltd. of Sydney 10%. ✦

Processing — *Quick Takes*

Husky to buy Valero's Lima, Ohio, refinery

Husky Energy Inc. has agreed to buy a 165,000 b/d refinery in Lima, Ohio, from Valero Energy Corp.

Husky Pres. and Chief Executive Officer John C. S. Lau said the company would integrate the refinery with "future growth of heavy crude oil and oil sands production."

The company produces more than 100,000 b/d of heavy oil in the Lloydminster region of Alberta and Saskatchewan and last year started production from the Tucker oil sands project in the Cold Lake area. Tucker output is to reach 30,000 b/d.

Husky operates a 28,000-b/d asphalt refinery in the Lloydminster area that also produces distillate used in a heavy-oil upgrader and condensate blended with heavy oil production. It also operates a 12,000-b/d light oil refinery in Prince George, BC, and ethanol plants in Minnedosa, Man., and Lloydminster.

For the Lima refinery it will pay $1.9 billion plus net working capital estimated at $200 million.

According to Oil & Gas Journal's latest Worldwide Report, the refinery's processing capacities include delayed coking 20,700 b/cd, fluid catalytic cracking 36,000 b/d, catalytic reforming 49,500 b/d, and catalytic hydrocracking 23,400 b/cd (OGJ, Dec. 18, 2006, p. 56).

GS Caltex sees 2010 start for Oman refinery

GS Caltex Corp. in 2010 will begin operating the 120,000 b/d refinery it has completed for state-owned Sohar Refinery Co. (SRC) in Oman.

GS Caltex—a 50-50 joint venture of South Korea's GS Holdings and Chevron Corp.—will operate the plant and transfer technical knowledge on refining for a royalty of $50 million from SRC.

Located in Sohar, a port city 240 km northwest of Muscat, the refinery has a 75,000 b/d residual fluid catalytic cracker. It will supply naphtha and propylene to a large petrochemical complex under construction nearby (OGJ, June 6, 2005, Newsletter).

Indian Oil to participate in Iraq oil projects

Iraq has invited India's largest refiner, Indian Oil Corp. (IOC), to establish refineries in war-torn Iraq and to participate in other downstream projects.

Indian Petroleum Minister Murli Deora and Iraqi Oil Minister Hussain Al-Shahristani met recently to exchange views on a host of such mutually beneficial projects.

Discussions revolved around the participation of two Indian state-owned enterprises in Iraq's oil and gas sector—refiner IOC in downstream projects, and explorer-producer ONGC Videsh Ltd. (OVL) in Iraq's upstream sector. OVL and Reliance Industries both have expressed interest in entering Iraq's oil exploration sector.

OVL, Reliance, and Algeria's Sonatrach had been in talks with the Saddam Hussein regime before United Nations' forces assumed control over Iraq in 2000. The talks were interrupted by UN sanctions after 2000.

Iraq has proved oil reserves of 112 billion bbl, which makes it the world's second largest oil nation behind Saudi Arabia. ✦

Transportation — *Quick Takes*

Sinotrans to store, ship oil for Sinochem

China's Sinotrans Group Corp. said it will begin providing global oil shipping and logistics services to Sinochem Corp.

Under an agreement signed Apr. 18, Sinotrans said it will provide Sinochem with oil transportation by sea, air, rail, and road as well as storage services, all aimed at increasing efficiency and lowering costs.

The Sinotrans statement, which did not stipulate the amounts the firm will transport, follows an Apr. 17 oil products shipping contract between China National Petroleum Corp. and Nanjing Oil Shipping Group, a subsidiary of China Chang Jiang National Shipping Group.

Under that contract, Nanjing will transport 600,000 tonnes of oil products in 2007, using 30,000-40,000 dwt tankers. Nanjing currently has nine product tankers and will increase its capacity through a further 24 vessels to be constructed by 2010.

The transport agreements are consistent with Chinese government policy, which promotes use of domestic shipping firms to curb foreign currency outlays and to assume a tighter grip of the country's energy supply chain.

CNOOC-ConocoPhillips FPSO hull complete

China National Offshore Oil Co. Ltd. (CNOOC) has completed the hull of the country's largest floating production, storage, and offloading unit.

The FPSO, called Offshore Oil 117, is a joint venture of CNOOC and ConocoPhillips China Inc. It can store 2 million bbl of crude and can process more than 190,000 b/d.

The finished hull will be shipped to Singapore from Shanghai for completion of the unit's topsides before being deployed by the end of 2008 to the Penglai 19-3 project in China's Bohai Sea.

The second phase of Penglai 19-3 is expected to go into production at yearend 2008 and produce 180,000 boe/d of oil.

JBIC loan enables ADNOC oil expansions

A $1 billion loan offered by the Japan Bank for International Cooperation to Abu Dhabi National Oil Co. is designed to secure stable supplies of crude oil to Japan while enabling ADNOC to expand existing fields, develop new ones, and improve production and oil transportation capabilities.

The loan—70% from JBIC and 30% from Japanese commercial banks—is being offered on condition that Abu Dhabi ensures steady exports of its crude oil to Japan.

ADNOC, along with repaying the loan, is expected to sign a long-term deal to export crude oil to Japanese oil companies over a 10-year period.

Four Japanese companies, including Japan Oil Development Co., are currently operating off Abu Dhabi, and the UAE is home to nearly half of the oil fields that Japanese companies are developing independently.

To ensure the security of its oil exports, Abu Dhabi is planning a 360-km pipeline that will bypass the Strait of Hormuz by carrying more than 1 million b/d of crude oil from production areas inside the Persian Gulf to the East coast port of Fujairah.

The UAE accounts for about 25% of Japan's total crude oil imports, about 95% of that coming from Abu Dhabi. The UAE also exports about 90% of its LNG production to Japan, according to the US Energy Information Administration.

Kalimantan-Java pipelay must start by July

The Indonesian government, reiterating an earlier warning, said it will revoke the special right granted to PT Bakrie & Brothers to build a 1,200-km natural gas pipeline from East Kalimantan to Central Java unless the company starts construction in July.

Energy and Mineral Resources Minister Purnomo Yusgiantoro said Bakrie, after winning the tender in July 2006, had been given 1 year to start work on the 15-trillion-rupiah ($1.65 million) project. He said Bakrie must have signed contracts with gas producers in East Kalimantan and consumers in Java by July 2007.

In March Tubagus Haryono, head of upstream oil and gas regulatory body BP Migas, also had warned that the right, which Bakrie won in last year's tender, would be reviewed if the company fails to start construction by July.

At the time, however, Bakrie Finance Director Yuanita Rohali said the company was awaiting publication of a government report on the country's gas balance, and the company had decided not to go ahead with the venture without a guaranteed supply of gas. Many industry officials earlier had cast doubts about the feasibility of the project due to declining gas reserves in East Kalimantan. ✦

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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.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 15-17.

INTERGAS IV International Oil & Gas Conference & Exhibition, Cairo, +44 20 7978 0081, +44 20 7978 0099, e-mail: erenshaw@thecwcgroup.com, website: www.intergasegypt.com. 15-17.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 15-17.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 17.

ERTC Asset Maximization Computing and Reliability Conference, Rome, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

Libya Oil & Gas Conference and Exhibition, Tripoli, +44 20 7978 0083, +44 20 7978 0099 (fax), e-mail: sshelton@thecwcgroup.com, website: www.cwclog.com. 21-24.

Asia Bottom of the Barrel Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: conferences@europetro.com, website: www.EuroPetro.com. 22-23.

NPRA Reliability & Maintenance Conference & Exhibition, Houston, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-25.

Africa Oil & Gas Trade & Finance Conference & Exhibition, Nairobi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 23-25.

Asia Petrochemicals and Gas Technology Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: conferences@europetro.com, website: www.EuroPetro.com. 24-25.

Contract Risk Management for the Oil & Gas Industry Conference, Jakarta, +00 603 2723 6745, +00 603

2723 6699 (fax), e-mail: CindyC@marcusevanskl.com, website: www.marcusevans.com/events/CFEventinfo.asp?EventID=12204. 28-29.

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

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

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

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Offshore Newfoundland Petroleum Show, St. John's,

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Newf., (403) 209 3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 19-20.

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

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

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

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

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

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

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

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

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

JULY

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

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

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

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

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

AUGUST

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

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

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

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

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

SEPTEMBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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Journally Speaking

Subsea advances in prospect

Guntis Moritis
Production Editor

An array of new technologies either commercial or nearly commercial is set to improve recovery from fields with subsea-completed wells.

The recent Offshore Technology Conference highlighted several technologies, including those for lowering subsea drilling and operations costs as well as those for subsea processing, multiphase boosting, and wet-gas compression.

Statoil

Statoil ASA has several initiatives for improving oil recovery from subsea-completed fields. Statoil's average recovery from these fields is 45.1%, but presentations at OTC said the company aims to increase this by 10% to move closer to the 60% recovery factor for its fields completed with dry-tree wells off platforms.

One of its nearly complete projects is the deployment of a subsea processing station at Tordis field off Norway (OGJ, May 7, 2007, p. 20). Developed by Kongsberg FMC and scheduled for installation in August, the station includes a separation vessel, desander, and injection pump for removing and disposing of most of the water and sand into an injection well as well as a multiphase booster pump for moving the oil, gas, and remaining bs&w to topsides processing.

With this subsea installation, Statoil expects the field's recovery factor to increase to 55% from the current 49%, which equates to an additional 35 million bbl of oil during the next 15-17 years.

Statoil is also lowering the costs of drilling and completing subsea wells. Its R&D efforts have developed a riserless light-well intervention vessel for reducing by one-third the costs of wireline service previously done from a semisubmersible. The vessel will be ready for work in 2008 and will operate at a cost of $150,000/day.

Another technology Statoil expects will reduce subsea well costs is through-tubing rotary drilling equipment placed on a dynamically positioned rig. The technology will allow sidetracks to be drilled in subsea wells for additional drainage. Statoil expects the system to be operational in 2007 and estimates that each sidetrack will cost $10 million.

Statoil plans to install a subsea raw seawater injection pump to support the reservoir pressure in Tyrihans oil field from Day 1. It expects Tyrihans to start producing in 2009, depending on processing capacity on the Kristin field semisubmersible production unit.

The company also is involved in developing subsea wet-gas compression and may start deploying the technology in 2011-12.

Last year Norsk Hydro, which now is part of Statoil, awarded Aker Kvaerner a contract for a subsea compression pilot for Ormen Lange gas and condensate field in the Norwegian Sea. Aker Kvaerner expects a final decision on the deployment in 2011.

Total

Later this year, Total E&P Nederland BV will install the world's first all-electric subsea production trees on two gas wells in 121 ft of water off the Netherlands in K5F field. Total expects the installation to improve production. Cameron Drilling & Production Systems manufactured the trees.

All-electric trees also can be a part of Cameron's CAMFORCE subsea processing system, which includes a Curtiss-Wright Flow Control Corp. and Leistriz AG subsea twin-screw multiphase pump, an all-electric separation unit, and a multiple application reinjection system (MARS). BP will install the first MARS on King oil field in the Gulf of Mexico.

Cameron describes MARS as a USB (Universal Serial Bus) port for subsea completions that allows installation of multiple processing technologies directly onto the subsea completion without disturbance to existing equipment. These technologies include such components as boosting, metering, and well stimulation.

Petrobras

Petrobras is another company with plans to deploy more subsea technology in several fields off Brazil, especially in those with limited deck space for additional processing equipment. As with Statoil in Tordis field, Petrobras has needs for separating out water from the oil subsea and reinjecting the water into disposal wells as well as for subsea boosting of the produced oil.

One problem it faces is the breaking of oil-water emulsions from fields producing heavy oil, such as the 20° gravity oil from Marlim field.

Presentations at OTC said Petrobras expects to implement subsea processing off Brazil in the next 5 years, with such mature fields as Marlim and Pampo having immediate potential for such equipment. Future needs are in fields such as Marlim Sul, Albacora, Marlim Leste, and Jubarte.

Petrobras will install subsea multiphase boosting in its Jubarte Phase II development. The company recently awarded Aker Kvaerner a contract for eight subsea boosting pumps as part of the artificial lift required to produce the heavy oil found in the field. ✦

Editorial

The energy rip-off

The senators are new to their jobs, and their bone-headed energy bill won't go far. But mischief isn't harmless just because it comes from inexperience.

"It is long overdue for the United State Congress to summon up the courage to stand up to the oil industry, one of the most powerful lobbies in Washington, DC, and to say very clearly, 'Stop ripping off the American people,'" said Sen. Bernie Sanders (I-Vt.) while explaining why he joined seven first-term Democrats supporting a bill for a "windfall profit" tax on oil companies. Another of the senators, Amy Klobuchar of Minnesota, said, "Oil companies have been ripping us off over and over and over again, and this is going to stop."

The bill's sponsor, Bob Casey of Pennsylvania, observed: "The Bush administration has let the oil companies run the pump for too long without any real investment in renewable fuels." Complaining that Pennsylvanian gasoline prices have increased "while oil companies continue to make billions in profits," Casey said his bill would "increase our energy independence while providing relief at the pump and taking away taxpayer subsidies for big oil."

What's overdue

If anything is "overdue," it's mature energy discussion free of repeatedly discredited accusations and ideas. Uninformed energy pronouncements, full of invective falsehood, are too common in Washington. They lead to too many mistakes, which are heaping too many unwarranted costs onto Americans.

Casey's bill, embracing concepts espoused by Sen. Hillary Clinton (D-NY) last year, would do just that (OGJ, June 12, 2006, p. 19). In elegant conflict with its purported aims, the proposal would lower energy independence and elevate oil prices. Its "windfall profit" tax would discourage development of US oil and gas supply. And its closing of "tax loopholes"—in the description of which Casey mistakes deductions for credits—would aggravate the effect. That damage would be minor, though, because the so-called loopholes aren't the lavish subsidies Casey portrays them to be. In further subversion of the proposal's stated goals, channeling proceeds of the tax measures to renewable energy and poor people would rush overpriced energy into the market and stimulate consumption.

This riot of contradiction should collapse under serious analysis. But it threatens to evade serious analysis by connecting with the enduring hatred many Americans feel toward oil companies. When junior senators who seem to know nothing about energy speak of oil companies "ripping off" consumers, they and their bad ideas capture attention they don't deserve. Oil companies therefore need to take accusations like this seriously and address them whenever and from whatever sources they arise.

Americans believe the rip-off myth because they hear it repeatedly. So the response bears repeating: Markets determine oil prices; companies don't. The market is too big and has too many buyers and sellers, all of them in competition with one another, to allow manipulation by any single company or group. Even the Organization of Petroleum Exporting Countries, with its strong influence over oil supply, can't manipulate prices to the extent Americans seem to believe. If OPEC, oil companies, or any other source of supply held that kind of market control, oil prices wouldn't have languished at levels that crimped suppliers' profits throughout the latter 1980s and 1990s.

Suppliers' profits

Prices are not now elevated because of sinister manipulation that has somehow come into force. They're elevated because expanding demand has encountered physical limits to supply. It's no rip-off that suppliers of a supply-constrained market profit from the inevitably increased prices. Are farmers ripping off anyone by profiting from corn prices newly elevated by ethanol mandates? Where were Sanders, Klobuchar, and Casey's other partners in demagogy when oil prices were abysmal and oil companies had to shed work and workers to make any money at all?

There is an energy rip-off in the US. It takes the form of wasteful energy initiatives undertaken in pursuit of chimeras such as energy independence and price relief engineered by governments. And it will continue until politicians begin seriously discussing energy and quit exploiting popular misunderstanding for political gain. ✦

Energy industry examining CO_2 sequestration options

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Global climate change presents challenges associated with balancing potential environmental impacts with a wide variety of economic, technical, and lifestyle changes that may be necessary to address the issue. Carbon dioxide emissions from the use of fossil fuels such as coal, oil, and natural gas are the largest anthropogenic contributor to greenhouse gases, which are believed to contribute to climate change. The overall objective of carbon management is to develop a strategy and portfolio of technologies for stabilizing CO_2 concentrations in the atmosphere and, thus, slow climate change.

Carbon sequestration is one class of carbon management technologies. It involves permanently sequestering and storing CO_2 in the earth. There are two broad classes of sequestration: terrestrial and geologic.

Terrestrial sequestration involves absorbing CO_2 from the air using biologic materials such as crops, trees, and grasses. Ultimately, the carbon is transferred to the soil in which the biologic materials grow. By optimizing the way we manage our land, we can do much to optimize the effectiveness of terrestrial sequestration around the globe. In geologic sequestration, the primary focus of this article, CO_2 is captured, compressed, transported by pipeline, and injected into deep reservoirs, such as saline formations, oil and gas reservoirs, and coal seams. This option is amenable to reduction of CO_2 emissions from point sources such as power plants and refineries. Such point sources contribute about half of the CO_2 emissions.

Before the CO_2 can be injected into a deep geologic reservoir, it first must be captured in a concentrated form from a fossil fuel-fired process such as those used for power generation or petroleum refining. Capturing CO_2 in a nearly pure form is necessary to minimize the volume needed for storage and so that the CO_2 can be compressed to a supercritical state. A number of pathways are currently available or under development for CO_2 capture. For example, in post-combustion capture, CO_2 can be scrubbed or otherwise removed from the flue gas after combustion of fossil fuels. However, this flue gas stream is relatively dilute, usually less than 15% by volume, making capture difficult and expensive. Commercial processes exist today for doing this based on absorption of CO_2 from the flue gas with monoethanolamine (MEA). However, the cost of capture due to the steam and energy requirements for the process makes it too expensive to be feasible for retrofit to existing plants in an efficient

manner. A number of improved processes are under development, including advanced MEA processes and more recently the ammonia-based capture, but these will require time to develop and commercialize.

Another option is to separate the CO_2 before combustion, precombustion capture. By first using a process called gasification, such as in integrated gasification combined cycle (IGCC) processes for power generation, fossil fuels such as coal and biomass can be converted into hydrogen and other components that can be used directly as a fuel or converted into other fuels such as those used for transportation today. Gasification can facilitate CO_2 capture by creating a relatively pure and concentrated CO_2 stream. The FutureGen project, funded jointly by government and industry, will utilize IGCC technology with the goal to build a near zero-emission coal-based power plant, including geologic sequestration of CO_2. The site for FutureGen has been narrowed to either Illinois or Texas. Final site selection is expected to be announced this year.

Another combustion type is oxy-combustion, which uses oxygen instead of air for combustion of fossil fuels in boilers, furnaces, and other processes and produces flue gas with a high concentration of CO_2 with the intent of facilitating its capture.

With the ongoing research and development, it is anticipated that there will be continuing improvements in the costs, integration of capture with power plant operations, and reduction in energy penalties for the capture technologies. In addition, there is a need to evaluate the CO_2 composition from various capture processes for permitting and injection purposes.

Geologic storage

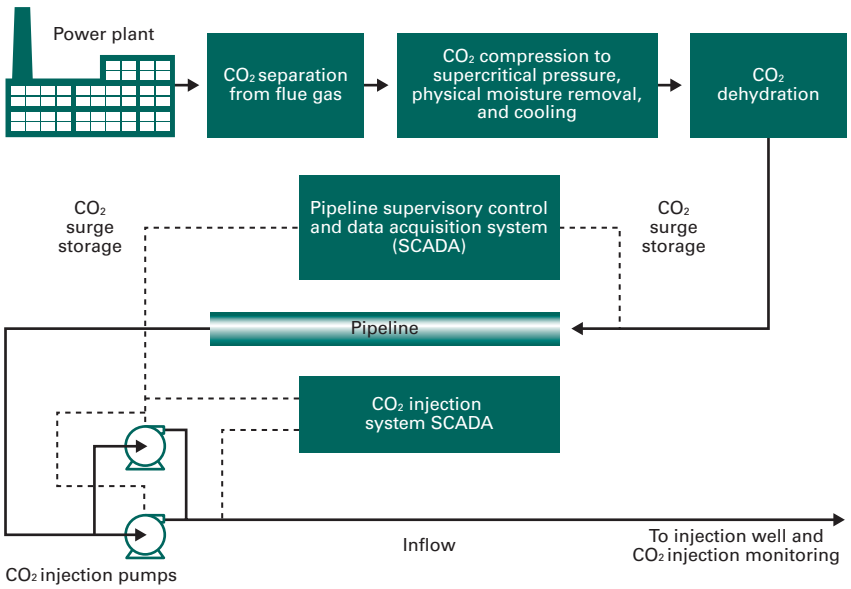
Sequestration in geologic formations builds on strong experience in the oil and gas industry. The primary types of geologic reservoirs for storing CO_2 underground are depleted oil and gas reservoirs, unmineable coal seams, and deep saline formations. The target reservoirs are typically, but not always, over 2,500 ft deep and consist of layers of sandstone or other porous rocks where CO_2 can be stored. The target reservoirs would also be capped by layers of nonporous rocks that act as seals to prevent the CO_2 from leaking out. Deep reservoirs are targeted because they are well away from drinking water supplies and because they are naturally at a pressure above about 1,100 psi. At this pressure or above, the CO_2 is in a supercritical state where its density is near that of a liquid, thus greatly reducing its volume compared to a gas. Also at these pressures, the CO_2 is less mobile than as a gas and, thus, more easily contained in deep geologic reservoirs for long periods. Recently the US Department of Energy (DOE) completed the first edition of a National Atlas describing these reservoirs and their capacities as estimated by DOE's Regional Carbon Sequestration Partnership Program. The atlas discusses the partnerships' estimated storage potential and implementation aspects in various reservoir types, such as:

- *Depleted oil and gas reservoirs.* Oil and gas fields are considered a natural choice for storing CO_2 for several reasons. They make attractive CO_2 sequestration targets since they have already proven their ability to contain oil, gas, and water for millions of years and their geologic character is well defined by previous exploration efforts. According to the atlas, these types of reservoirs in the US are estimated to contain about 90 gigatons of storage capacity. Currently, CO_2 is injected in depleted oil fields to enhance oil recovery because under suitable reservoir conditions CO_2 mobilizes the oil trapped in fine pore spaces through miscible or immiscible displacement processes. The US is a world leader in enhanced oil recovery (EOR) technology, using about 30 million tonnes/year of CO_2 for this purpose, mostly from natural CO_2 sources. However, these are primarily operated as EOR projects with an effort to maximize economic returns through CO_2 recycling rather than maximizing CO_2 storage in the reservoirs. CO_2 injection also may be used to maintain reservoir pressure in depleted oil and gas zones. Enhanced oil and gas recovery offers

Through the Midwest Regional Carbon Sequestration Partnership, Battelle scientists drilled an 8,000 ft test well at First Energy's R.E. Burger Plant near Shadyside, Ohio, to evaluate CO_2 storage potential in Appalachian basin. Drilling was completed in February. Photo from Battelle.

GEOLOGIC SEQUESTRATION SYSTEM*

Fig. 1



Source: Battelle
*Not to scale

a near-term potential for geologically storing CO_2, as well as an opportunity to sequester carbon at low cost, due to the revenues from recovered oil or gas. Of course, for anthropogenic CO_2 to be useable, an appropriate match between sources and sinks is needed, and that might not be possible in many locations.

• *Unmineable coalbeds.* CO_2 can be injected onto coal seams that are considered unmineable—the seam is too thin, too deep, or otherwise does not allow for the coal to be economically recovered. There is much debate about how to define what coal seams fall into this category since technology for recovering coal continues to evolve making coal that is unmineable today potentially is mineable tomorrow. It is estimated that in the US unmineable coal seams represent a potential storage target of over 170 gigatons of CO_2. The primary economic benefit of this option is that it can be used for enhanced coalbed methane production (ECBM), because the coal seams have a greater affinity for CO_2 adsorption than for methane. Typically, the amount of CO_2 adsorbed or sequestered on the coal surface is much greater than the amount of carbon produced as methane. Because the CO_2 for ECBM can be injected in gas phase, this technology can be deployed at shallower depth compared to other options. A key limitation is the potential environmental issues and cost associated with an increase in produced water from the gas production.

• *Deep saline reservoirs.* Deep saline reservoirs are sedimentary formations such as sandstones and carbonate rocks that have pore spaces filled with saline water or brine. In the shallower sedimentary layers, the pore spaces have fresh water, but with increasing depth the water salinity increases to high levels such that it is no longer useable for drinking or industrial uses. The presence of highly saline brine in these formations also indicates that these have been isolated from leakage from freshwater zones for a very long time. Further, these layers must be overlain by low-permeability and unfaulted caprock such as shale or dense limestone so that the injected fluids do not leak into the freshwater zones or the atmosphere. Typically, depths greater than 2,500 ft are suitable because at these depth the injected CO_2 is likely to remain in a dense and less mobile supercritical phase. They have two important benefits as CO_2 storage targets. First, the estimated carbon storage capacity of saline formations in the US is very large, estimated to be several thousand gigatons, making them a viable long-term target for storage of CO_2 from large point sources. And second, many existing large CO_2 point sources in the US are within relatively close proximity to a potential future saline reservoir injection point, making it feasible to consider transporting CO_2 from the source to the reservoir or even injecting CO_2 onto a reservoir at the source site itself.

Theoretically, geologic reservoirs have the capacity to store all the CO_2 produced by the large point sources of CO_2 in the US and globally for hundreds of years. However, in practical terms, each major CO_2 source has to be evaluated individually relative to its proximity to potentially suitable reservoirs, the economics of implementing CO_2 capture, and the feasibility of transporting the CO_2 to the injection site. The large volumes of CO_2 involved, over 5 million tonnes/year from a single major US coal-fired power plant, make pipeline delivery of supercritical CO_2 the only practical means of transport.

Sequestration projects

Geological sequestration of CO_2 has been seen as a prominent option only during the last 10 years or so. However, in this time, significant progress has been made in evaluating this option through paper studies, computer and laboratory tests, pilot demonstrations, and commercial projects. Examples of large-scale projects include the Weyburn project in Canada, where EnCana Corp. uses CO_2 that comes via a 200-mile pipeline from a coal gasification plant near Beulah, ND. Similarly, large-scale injection of about 1 million tonnes/year of CO_2 from gas purification into deep saline reservoirs is under way at Sliepner field in North Sea and at the In Salah project in central Algeria. Another large-scale project under planning is the FutureGen project, which will use coal gasification to produce power and

DOE partnerships testing sequestration

Paula Dittrick
Senior Staff Writer

A government-industry task force is working to develop technologies and infrastructure for carbon capture and sequestration with the goal of reducing greenhouse gas (GHG) emissions that can contribute to global climate change. The goal is safe, cost-effective, and long-term carbon mitigation, management, and storage.

The US Department of Energy in 2003 organized seven Regional Carbon Sequestration Partnerships. The RCSPs currently are field-testing sequestration as part of the validation phase, which ends in 2009. The validation phase is the second in the three-phase program. More than 30 validation projects are planned by the RCSPs—a network of more than 300 state agencies, universities, and private companies spanning 40 states, three Indian nations, and four Canadian provinces.

A deployment phase, slated for 2008-17, involves several large-volume sequestration tests to demonstrate that sequestration sites have the potential to store hundreds of years of regional CO_2 emissions.

The National Energy Technology Laboratory oversees the RCSPs. The DOE sequestration research program supports other US and United Nations GHG mitigation efforts. In addition, DOE belongs to the Carbon Sequestration Leadership Forum, an international collaboration on climate change. Six forum member nations are participating in RCSP's validation projects.

Partnership activities

The Big Sky Carbon Sequestration Partnership (BSCSP) plans field tests in basalt formations and sedimentary rock hosted saline formations to assess mineral, chemical, and hydrologic effects of injected CO_2.

Researchers will test how well volcanic rocks abundant below the Columbia and Snake River plains store CO_2. They plan to inject the gas into subterranean volcanic basalt rock and monitor whether the rock can hold it.

BSCSP also is conducting a reactive carbonate reservoir assessment examining long-term CO_2 mineralization rates in carbonate rocks. This involves enhanced oil recovery (EOR) operations at Lost Soldier and Wertz oil fields in south-central Wyoming. The consequences of long-term exposure of carbonate rocks to CO_2-rich fluids are being studied through pre- and postinjection core comparisons.

Big Sky partnership's area includes Idaho, Montana, Wyoming, and South Dakota as well as eastern Washington, and Oregon.

The Midwest Geological Sequestration Consortium is investigating options for CO_2 storage in oil reservoirs, coal seams, and deep saline water-bearing formations in the Illinois basin, where all three potential geologic storage opportunities exist in proximity to substantial CO_2 sources.

The Illinois State Geological Survey is the lead technical contractor for the consortium. The MGSC covers all of Illinois, southern Indiana, and western Kentucky.

The Midwestern Regional Carbon Sequestration Partnership (MRCSP), led by Battelle, Columbus, Ohio, is conducting three deep saline reservoir tests in Appalachian basin, Michigan basin, and Cincinnati Arch geologic regions. MRCSP completed drilling of an injection and a monitoring well at the Michigan basin site hosted by DTE Energy and Core Energy. An injection well permit has been submitted, and an injection phase is planned for late 2007.

MRCSP has also completed seismic surveys at the Duke Energy's East Bend Station, a coal-fired plant in Boone County, Ky., near Cincinnati and at FirstEnergy's R.E. Burger Plant near

hydrogen in a near-zero emission plant with CO_2 sequestration.

While a small number of current large-scale projects provide valuable experience, there is a strong need to build a foundation for the technology through evaluating storage potential in various regions of the US and the world—a purpose served in the US by the regional carbon sequestration partnerships. As part of an effort to further develop carbon sequestration technologies and develop ways to reduce CO_2 emissions while protecting the industrial economy of the Midwest, Battelle is leading the Midwest Regional Carbon Sequestration Partnership (MRCSP) for the DOE and 30 other partners. The MRCSP covers eight states (Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia). The MRCSP is one of seven partnerships in the DOE Regional Carbon Sequestration Partnership Program.

In Phase I, the MRCSP focused on defining the region's existing sources of CO_2, geological and terrestrial reservoirs, potential options for transporting CO_2, regulatory framework, and economics of implementing sequestration opportunities in the region, as well as reaching out to public stakeholders to educate them about sequestration and receive their feedback on key issues.

In Phase II, which began in 2005 and is scheduled to end in 2009, the MRCSP's research is building on the Phase I results by using a series of field validation tests to determine how the region's large, well-distributed, and competitively priced sequestration potential can be used to simultaneously advance economic growth and environmental protection. Three of the field tests involve implementation of geologic sequestration by injecting CO_2 into deep saline formations in Ohio, Michigan, and Kentucky. A noteworthy

Shadyside, Ohio. Drilling of an 8,000-ft test well was completed at the Burger Plant, and a permit application will be submitted after evaluation of the well data with injection planned during 2008. The Burger power plant is also the planned site for a CO_2 capture test, a potential source of CO_2 for geologic testing. Test drilling at the East Bend Station is planned for late 2007.

The Plains CO_2 Reduction Partnership (PCOR) is investigating sequestration technologies across the central US and into Alberta. The region includes the Weyburn geologic sequestration project. The partnership represents Iowa, Missouri, Minnesota, North Dakota, Nebraska, Montana, South Dakota, Wisconsin, and Wyoming.

Validation projects

PCOR is developing three geologic field-validation projects. Acid gas (70% CO_2 and 30% hydrogen sulfide) from gas processing plants in northern Alberta will be injected into an oil-producing zone in an underground pinnacle reef structure. Results will help expand understanding of the effects of H_2S on tertiary oil recovery and CO_2 sequestration.

CO_2 will be injected into an oil-bearing zone at great depth in Beaver Lodge field in northwestern North Dakota to determine the efficacy of sequestration and EOR using CO_2 there. Unmineable lignite seams in northwestern North Dakota will be injected with CO_2, which researchers say will be trapped by naturally bonding to the surfaces of the fractured lignite. This validation test is expected to increase knowledge about lignites for both CO_2 sequestration and enhanced coalbed methane production.

Southeast Regional Carbon Sequestration Partnership, led by the Southern States Energy Board, Norcross, Ga., plans a stacked storage project along the Gulf of Mexico coast. Researchers, led by the Gulf Coast Carbon Center at the University of Texas, will investigate a stacked sequence of hydrocarbon and brine reservoir intervals.

A separate test at Mississippi Power Co.'s Victor J. Daniel coal-fired power plant near Escatawpa, Miss., will focus on validating CO_2 storage in a deep saline reservoir near large coal-fired power plants along the Mississippi Gulf Coast. A project team, led by Electric Power Research Institute and Southern Co., has identified the Lower Tuscaloosa formation as a high-capacity CO_2 storage option.

Other field tests involve two coal seam projects in the Black Warrior basin and the Appalachian basin. States represented in the partnership are Arkansas, Louisiana, Mississippi, Tennessee, Georgia, Florida, North Carolina, and South Carolina.

Southwest Regional Partnership on Carbon Sequestration, led by the New Mexico Institute of Mining and Technology, plans field tests in the San Juan basin in New Mexico, Paradox basin in Utah, and the Permian basin in Texas. This includes the SACROC Unit in Texas and Aneth oil field in Utah.

The tests involve various carbon-sink targets, including deep saline sequestration, EOR and sequestration, and enhanced coalbed methane production. In some cases, geologic sequestration tests are being combined with terrestrial tests.

West Coast Regional Carbon Sequestration Partnership (WESTCARB) is a coalition of more than 70 agencies and companies from Arizona to British Columbia. The California Energy Commission is leading the partnership's pilot test.

WESTCARB plans to inject CO_2 3,000 ft underground near Thornton, Calif., into deposits of porous sandstone and salt water capped by a layer of shale. Commercial-grade CO_2 will be trucked in and injected. Ultimately in commercial applications, emissions from industrial sources could be sequestered in this manner.

feature of these tests is that they are hosted or sponsored by major regional utilities, which increases the probability of commercial implementation in the future. Similar tests are being implemented by other partnerships, and DOE recently announced plans for larger-scale demonstrations.

Another noteworthy project has been under way at American Electric Power's Mountaineer Plant in New Haven, W.Va., to evaluate geologic storage potential in the Appalachian basin, a key area for coal-fired power generation. This project funded by DOE, AEP, and others and operated by Battelle has completed a detailed site characterization through seismic survey, test well drilling, and modeling. AEP recently announced plans to proceed with an extensive injection and monitoring phase with CO_2 to be provided from an experimental capture technology demonstration. It will be the first use of carbon capture technology on a commercial scale at a coal-fired power plant and will provide a test case for retrofitting of existing plants. These projects represent an example of an expedited pace in development and deployment of carbon sequestration technologies.

Accounting framework

The US currently has no national regulations governing CO_2 emissions. There are a number of voluntary trading markets, including the Chicago Climate Exchange.

There are state initiatives such as that implemented by California and a number of northeastern states through the Regional Greenhouse Gas Initiative. It is possible that, at some point in the not-too-distant future, national regulations will be implemented that will regulate emissions of CO_2 from various sources.

The imposition of such regulations creates a range of uncertainties for

CO_2-RELATED WEB SITES

Carbon Sequestration Leadership Forum:
http://www.cslforum.org

Intergovernmental Panel on Climate Change:
http://ipcc-wg1.ucar.edu/index.html

DOE Atlas for regional partnerships:
http://www.netl.doe.gov/publications/carbon_seq/atlas/index.html

FutureGen: www.FutureGenAlliance.org

Petroleum Industry Guidelines for Reporting GHG Emissions:
www.ipieca.org/downloads/climate_change/GHG_Reporting_Guidelines.pdf

Battelle-developed SANGEA Emissions Estimation Software:
http://ghg.api.org

DOE Carbon Sequestration Regional Partnerships

Overview by National Energy Technology Laboratory:
http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html

Big Sky Carbon Sequestration Partnership:
http://www.bigskyco2.org

Midwest Geological Sequestration Consortium:
http://www.sequestration.org

Midwest Regional Carbon Sequestration Partnership:
http://198.87.0.58/Default.aspx

The Plains CO_2 Reduction Partnership:
http://www.undeerc.org/pcor/default.asp

Southeast Regional Carbon Sequestration Partnership:
http://www.secarbon.org

Southwest Regional Partnership on Carbon Sequestration:
http://www.southwestcarbonpartnership.org

West Coast Regional Carbon Sequestration Partnership:
http://www.westcarb.org

those affected. While companies know the amount of emission reductions they need, figuring out the most cost-effective way to achieve these reductions is not an easy task. Companies may change their operations to reduce their emissions, or they may acquire emission allowances from other companies that do not need them. They also may acquire approved emission-reduction credits created under two project-based mechanisms under the Kyoto Protocol: the Joint Implementation (JI) or Clean Development Mechanism (CDM) programs.

JI allows industrialized countries to fulfill part of their required greenhouse-gas emission reductions by paying for emission-reducing projects in other industrialized countries. CDM allows industrialized countries to invest in emission-reducing projects in developing countries.

In addition to the voluntary or state initiatives in the US, experiences in carbon control and trading in other countries provide valuable lessons. Major capital investments that may reduce greenhouse-gas emissions will often have lifetimes that extend far past 2012, when the Kyoto Protocol and the first phase of the European Emissions Trading Scheme expire. The exact mechanism, scope, and participation levels that will emerge after 2012 remain uncertain. During the first year, the market price of European Union emission allowances has been volatile, reaching over $30/tonne of CO_2 equivalent in the summer of 2005 but decreasing substantially after that. JI and CDM emission reduction credits can be acquired for a fifth of this amount. However, until these credits are actually created and approved, uncertainty exists as to whether they will be delivered and useable in the EU program.

Businesses—faced with uncertainties in mechanisms combined with an anticipation of US carbon controls—find themselves taking a more comprehensive stock of their climate control-related risks and options. Battelle has quantified the emission reductions and cost-effectiveness of greenhouse-gas emission-reduction technologies and has assisted international companies (steel, petroleum, utilities) with understanding their emissions and options for reducing them. Specific projects include working with the International Petroleum Industry Environmental Conservation Association, International Association of Oil & Gas Producers, and the American Petroleum Institute to

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develop guidelines for reporting emissions and supporting individual companies in conducting corporate emission inventories using the Battelle-developed SANGEA Emissions Estimation Software.

Building experience

A number of modeling studies and forecasts demonstrate that no single measure will stabilize atmospheric concentrations of CO_2 at a safe level—there is no silver bullet.

These studies, including those done as part of the Global Technology Strategy Program by the Joint Global Change Research Institute, show that a suite of technologies will be required and that sequestration of CO_2 from fossil fuel processes will be an important factor if we are to continue taking advantage of economical fossil fuels.

If carbon sequestration is not undertaken, the use of fossil fuels may have to be severely diminished, with significant consequences for the world's economy. The current pilot-scale field projects funded by the government and industry provide a unique opportunity to build expertise and experience in this technology so that a broader deployment can be undertaken in the future with greater public confidence and in compliance with national and international greenhouse gas mitigation regulations. ✦

Senate panel adds price gouging provision to CAFE bill

Nick Snow
Washington Correspondent

A US Senate committee added an amendment that would make gasoline price gouging a federal crime, and then the committee approved a bill to improve automotive fuel efficiency requirements.

The Commerce, Science, and Transportation Committee on May 8 approved by voice vote S. 357, which would raise Corporate Average Fuel Economy standards and add the requirements to medium and heavy-duty trucks, after adopting the price gouging amendment offered by committee member Maria Cantwell (D-Wash.).

"Regular gas prices in Washington state are averaging $3.40 right now. That's higher than last year or in the aftermath of Hurricane Katrina. We need better consumer protections on the books," Cantwell said after the hearing. "Gas prices and oil company profits are both at record levels, and consumers are left with no way of knowing whether they're being taken for a ride."

Her amendment, which she introduced last week as a separate bill, would give the US Federal Trade Commission power to investigate allegations of fuel price manipulation. The US Department of Justice would enforce criminal penalties for gasoline price gouging during national emergencies, such as the oil market disruptions following Hurricane Katrina in 2005, she said.

The amendment's adoption prompted Charles T. Drevna, executive vice-president of the National Petrochemical & Refiners Association, to express concern over its potential consequences.

"Legislation that attempts to curtail the activity of free markets will inevitably harm consumers," Drevna said. "During times of emergency and supply disruption, rising prices play an important role in limiting economic harm. They signal suppliers to increase production and bring fuel to affected areas while at the same time encouraging consumers to conserve.

His comments came in a letter to Daniel K. Inouye (D-Ha.), the committee's chairman, and Ted Stevens (R-Ark.), its vice-chairman.

Rumblings in House

Meanwhile, two House subcommittee chairman separately announced that they would hold hearings to investigate causes of higher gasoline prices.

Rep. Bart Stupak (D-Mich.), who chairs the Energy and Commerce Committee's Oversight and Investigations Subcommittee, said on May 8 that the subcommittee will examine causes of fluctuating fuel prices in a hearing expected in the next 4 weeks.

"When there is little transparency in how a product like gasoline is priced, there is room for gouging," said Stupak, who introduced a bill in February to give the FTC the power to investigate fuel price manipulation allegations.

His announcement followed one on May 3 by Rep. Dennis J. Kucinich (D-Ohio), chairman of the Oversight and Government Reform Committee's Public Policy Subcommittee, of a hearing on June 7 to address high gasoline prices.

Kucinich said he sent a letter to chief executives of seven major oil companies on Apr. 10 demanding explanations for record gasoline prices. He is reviewing their responses.

"I have long been concerned about the activities of oil companies," Kucinich said. "I will be asking them pointed questions to determine if manipulation is a factor in raising prices." ✦

House panel postpones BP oil leak hearing

Nick Snow
Washington Correspondent

A US House Energy and Commerce Committee's subcommittee postponed its May 3 hearing on BP America Inc.'s management of Alaska North Slope crude oil gathering operations until May 16.

The Oversight and Investigations Subcommittee said it took the action

after discovering that BP withheld key documents related to anticorrosion cost-cutting at the field, which was partially shut down in August 2006 due to corrosion.

BP American Chairman Robert A. Malone requested the postponement in an Apr. 30 letter to subcommittee chairman Bart Stupak (D-Mich.) and chief minority member Ed Whitfield (R-Ky.). Malone stated that he had not received the documents, nor had the president of BP Alaska or the subcommittee.

"Second, some of the documents recently produced to the subcommittee raise concerns about previous spending decisions that cause me concern. We need time to determine how the concerns and frustrations expressed by workers were ultimately resolved," Malone continued.

He said he was troubled by the extent to which the workforce apparently was frustrated during 2004-05 and that he wants to eliminate such frustration "by creating a culture in which workers are confident their concerns will be heard and addressed."

He said this will take time, but BP is changing the way it manages its business and is creating a positive safety culture.

In an Apr. 2 response, John D. Dingell (D-Mich.), who chairs the full committee, and Stupak told Malone that BP supplied information Apr. 17 after numerous requests for such material "going back nearly a year" and that the documents "reveal important internal decisions suggesting a severe cost-cutting atmosphere existed in [BP's] crude oil production operations at Prudhoe Bay."

Some documents discuss stopping the injection of a corrosion inhibiter to meet budget targets, while others suggest that other corrosion mitigation activities were reduced or postponed due to spending constraints, they told Malone.

"We now know that BP proceeded with cost-cutting measures that may have compromised pipeline safety while earning $22 billion in profits. What we don't know is why," Dingell said as he and Stupak announced the hearing's postponement. ✦

Preliminary final 5-year OCS plan draws fire, support

Nick Snow
Washington Correspondent

US Outer Continental Shelf oil and gas development opponents complained that the Department of the Interior and Minerals Management Service's preliminary final 5-year OCS plan goes too far, while proponents declared that it doesn't go far enough.

They reacted soon after the Apr. 30 joint announcement that 21 OCS oil and gas lease sales are scheduled in eight planning areas from July 1, 2007, through June 30, 2012 (OGJ Online, Apr. 30, 2007). The proposed leasing includes new acreage in the eastern Gulf of Mexico, in the Bristol Bay area off Alaska, and off southeastern Virginia.

Rep. Maurice Hinchey (D-NY) pledged to use his seats on the Interior Appropriations Subcommittee and Natural Resources Committee to block as much of the leasing as possible.

"The plan is short-sighted and will have dramatic repercussions for many years to come. In exchange for making small profits off oil and gas drilling leases while providing its friends in Big Oil with new sources of income, the Bush administration is giving the green light to permanently scarring the environment and ecosystems of these areas, especially Bristol Bay," he declared on Apr. 30.

But Rep. John E. Peterson (R-Pa.), who also sits on the Interior Appropriations Subcommittee, said the preliminary final plan (PFP) "paradoxically extols the benefits of OCS energy production, while at the same time recognizing the president must lift his moratorium for this to become a reality."

He criticized President George W. Bush for not immediately removing the OCS withdrawals enacted by President George H.W. Bush and extended by President Bill Clinton. Peterson said he would work to lift congressional OCS leasing bans, which must be renewed annually.

Association reactions

The American Petroleum Institute said in an Apr. 30 statement that it was encouraged by the inclusion of new OCS areas off Alaska and Virginia in the PFP, but added that some 80% of the federal OCS containing an estimated 18.9 billion bbl of oil and 85.9 tcf of gas remain off-limits.

API said, "This is enough oil to heat 9 million homes and power 20 million cars for 30 years and enough gas to heat 37 million homes for 30 years. Despite anticipated 'robust growth' in renewables between 2007 and 2030, the US Energy Information Administration projects an increase in oil consumption of nearly 30% and of natural gas consumption of nearly 19% over the same period. The rich energy resources now locked up off our coasts will clearly be needed."

Independent Petroleum Association of America Pres. Barry Russell said the PFP is a positive step as he also called for removals of the presidential withdrawals and congressional moratoria.

"The fact that 75% of the comments MMS received from the public supported some level of increased access to the American energy resources in the OCS should serve as a wake-up call for Congress to discontinue its antiquated policies toward energy development and support the administration's effort to make American natural resources

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available to American consumers," he said on Apr. 30.

National Association of Manufacturers Pres. John Engler also called for increased access to the OCS, as well as more investment and research in energy efficiency, on Apr. 30 in response to the PFP.

"Manufacturing requires adequate and affordable energy prices—to fuel factories, ship products, and manufacture consumer goods. Historically high energy rates and rising consumer demands are crippling manufacturers, large and small, facing fierce global competition. It's in the best interest of our nation, our manufacturers and our consumers to lay a sound foundation of energy sustainability," he said. ✦

Barnett to spar Hugoton for top US natural gas field

Newark East field in North Texas, center of the Mississippian Barnett shale play, was Texas's largest gas-producing field in 2006 and could become the largest in terms of ultimate recovery in the Lower 48.

The field ranked third in the nation in reserves, after the entire San Juan basin in New Mexico and Colorado and Pinedale field in the Green River basin in Wyoming, and second in the nation in terms of production after San Juan.

Eleven articles totaling more than 220 pages describe numerous aspects of the Barnett shale formation in the April 2007 issue of the American Association of Petroleum Geologists Bulletin.

One article states, "Several individuals who have worked the Barnett play believe that the greater Newark East field will eventually surpass the Hugoton field of Kansas, Oklahoma, and Texas as the largest onshore gas field in the conterminous US."

The Kansas and Oklahoma portions of Hugoton have produced 35 tcf of gas from two conventional formations and could have another 20 tcf recoverable, a recent study said (OGJ Online, Apr. 27, 2007). The US Geological Survey in 2004 estimated the Barnett's potential at 26.2 tcf of undiscovered recoverable gas, excluding possible increased recovery as a result of horizontal drilling.

The 26.2 tcf applies to an area of more than 4 million acres. The play is considered to have 3-4 tcf of proved reserves, leading to a total resource of more than 30 tcf as most recently envisioned.

How the play grew

Discovered by the former Mitchell Energy Corp. in 1981 in Wise County, Newark East field attracted the drilling of only 100 wells between 1981 and 1990, wrote David F. Martineau, Pitts Oil Co. LLC, Dallas, in the AAPG lead article.

The field has been divided into the original core area where the Barnett overlies the Ordovician Viola limestone and the expansion area where it sets atop the Ordovician Ellenburger Group. The early drilling was in Wise and Denton counties, and development has now spread to more than 30 counties underlain by the Fort Worth basin and Bend arch.

Federal tax credits that expired in 1993 for gas produced from tight sands and state severance tax relief that continues today helped spur Barnett shale gas development.

Numerous other Barnett shale field names include JMG Mag field in Jack County, Cleburne field in Johnson County, and St. Joe Ridge field in Montague County.

The field(s) had produced 2.3 tcf and

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

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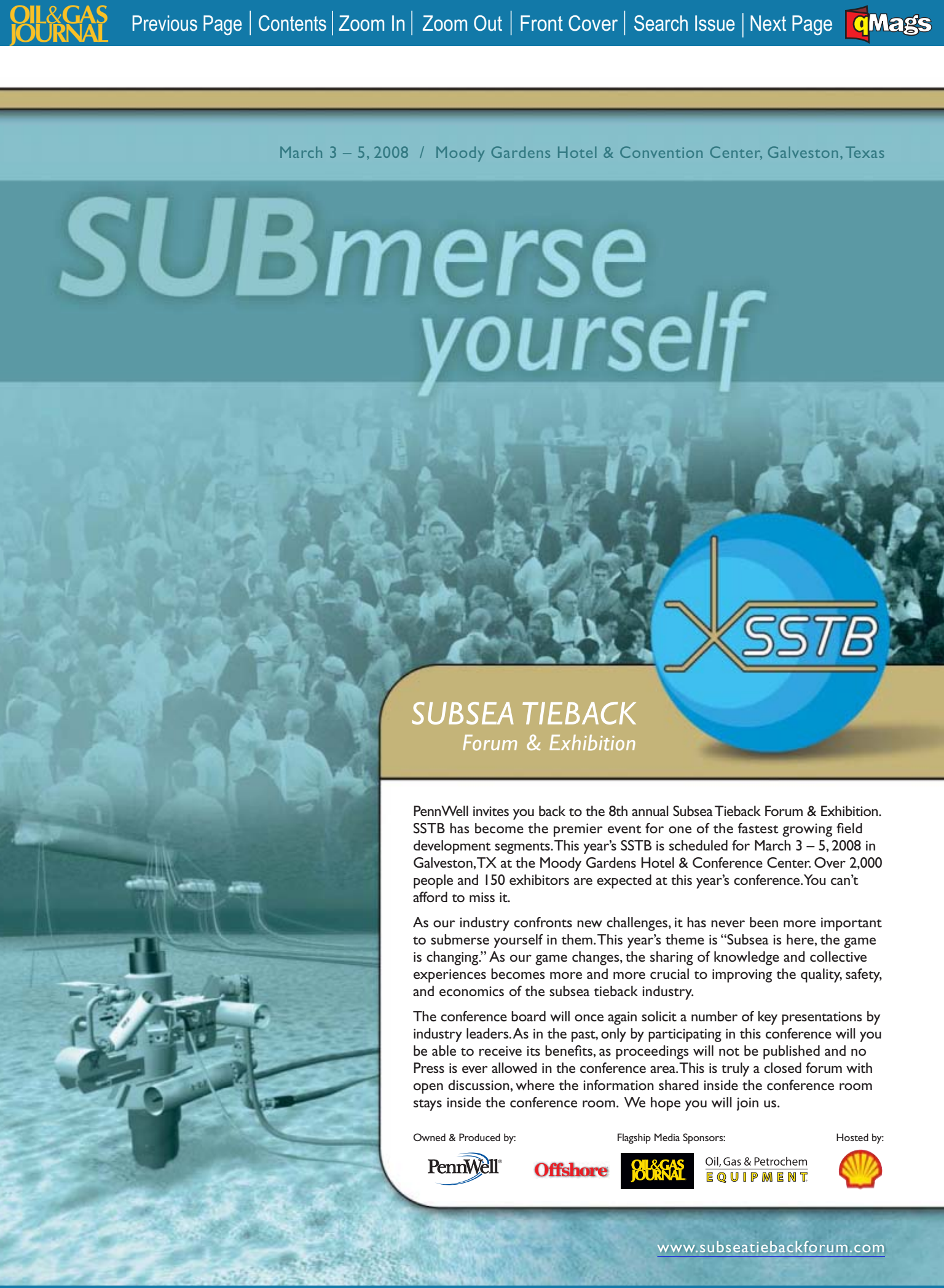

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As our industry confronts new challenges, it has never been more important to submerse yourself in them. This year's theme is "Subsea is here, the game is changing." As our game changes, the sharing of knowledge and collective experiences becomes more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

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

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WATCHING THE WORLD

Eric Watkins, Senior Correspondent

China touts Nanpu find

The Chinese can hardly contain their glee over the recent discovery of Nanpu oil field in Bohai Bay. The find, they say—when slowing down long enough to talk—is the country's largest in decades.

"Discovery of such a major oil field offers great flexibility and initiative for the country to plan and adjust its energy strategy," said Hu Wenrui, vice-president of CNPC subsidiary PetroChina, which announced on May 3 a 1.02 billion-tonne reserve of oil equivalent on the Nanpu Block.

"The Bohai Bay is a relatively mature area and this new discovery is encouraging," Mark McCafferty, the lead analyst for Southeast Asia at energy consultant Wood Mackenzie, told Reuters. "I'm sure it is a big find but exactly how big is uncertain as they tend to have a different methodology for reporting reserves in China."

Don't they indeed! One wonders if this find was orchestrated by the ministry of information instead of sober oil executives.

Just in time

According to reports in the official Shanghai Securities News, China's newest "discovery" will boost the country's crude oil reserves by 55% and its gas reserves by 9%. Most important, officials insist, the field will reduce China's reliance on imports.

Well, for a while, anyway. If all 1.02 billion tonnes of oil equivalent in the field really do prove to be recoverable, that will cover about 3 years of national requirements since China consumed around 320 million tonnes of oil last year.

The discovery comes just in time, too, as the aging Daqing oil field in northeastern Heilongjiang province, China's main domestic source of supply for 30 years, saw annual output drop below 50 million tonnes in 2003.

Things are really going to change as a result of the new find, officials trumpet. CNPC said it will start to develop the Nanpu oil field as soon as possible, with the first-phase project, to be finished by 2012, yielding 10 million tonnes/year.

More to come

PetroChina's Hu said, "This year's production target for the Jidong Nanpu oil field is 2.2 million tonnes, with substantial annual increase scheduled from this year on. By 2012, we expect the oil field to roll out 10 million tonnes of crude every year."

After that, officials declared, output is expected to rise progressively to 25 million tonnes/year, making the new field China's third largest after Daqing and Shengli.

And the party's hardly over yet, according to other experts. "It's possible for PetroChina to discover more oil at Bohai Bay, with new exploring technologies and theories to be adopted," said Han Xuegong, a senior consultant with CNPC.

Not waiting to be left off the bandwagon, China's top offshore oil and gas company, CNOOC Ltd., also is expecting "a cluster of quality oil and gas fields" to be discovered at Bohai Bay, which will become a "major driving force" for the firm's future output.

Uh huh. Sure. Tell us another one. ✦

was making 2 bcfd of gas as of July 2006, Montague wrote.

Operators completed more than 6,200 wells through September 2006, more than 5,800 wells were on production, and hundreds of others were drilled, completed, or awaiting a pipeline.

Technology advances

The main technology improvements have been shale gas-in-place evaluation, geologic relationships, wellbore designs, and completion techniques, Martineau wrote.

Canister desorption tests in the late 1990s-early 2000s on wells with nearly identical total organic carbon values indicated that gas recovery from the Barnett shale would be more than double what was previously thought. Also, the formation has an above-normal pressure gradient in the core area that reaches 0.54 psi/ft.

Operators have used 3D seismic surveys since 2001 mostly outside the core area where the size and strike of the faults and number and size of karsts are more random.

Mitchell Energy began pursuing the Barnett shale in the early 1980s. The company had a large acreage position in Boonsville (Bend Conglomerate) field, which had produced 1.67 tcf of gas in 30 years. The field's decline left infrastructure that needed a new play to remain economic.

Mitchell produced 1.35 bcf in 24 years from its first 1981 Barnett shale completion, which Martineau described as a "supposedly original noncommercial well."

Vertical drilling was the primary drilling method until 2002. More than 1,900 horizontal wells have been drilled. Hydraulic fracturing advanced through several generations until the onset in 2006 of the "simo-frac," in which an operator simultaneously fracs two parallel horizontal well bores 500-1,000 ft apart.

It remains to be seen whether the Barnett will be economic in areas where it thins to 100-150 ft. ✦

OFFSHORE ENERGY LOSS—2

Insurance statistical analysis provided for marine E&D

Mark J. Kaiser
Allan G. Pulsipher
Louisiana State University
Baton Rouge

This is the second of three parts on insurance loss statistics and their role in risk management in offshore exploration and development operations.

Part 2 is a summary of the scale of insured loss in the offshore energy industry by cause, category, and region using the Willis Energy Loss database.

Energy loss statistics play an important role in calibrating and verifying risk management software and are useful to gauge the state of the insurance market.

Risk events associated with offshore energy exploration and production occur infrequently but have the potential of generating large losses. Blowouts, design/workmanship, heavy weather, and fire/lightning/explosion represent the largest loss categories for offshore basins across the world.

Introduction

Offshore oil and gas production takes place in a confined space in a hostile and uncertain environment under the constant danger of catastrophe and loss.

Drilling, processing, construction, installation, and transportation activities involve significant financial and safety risks. It is possible to engineer some risks to a low threshold of probability, but losses and unforeseen events cannot be eliminated because of cost considerations, the human factor, and environmental forces.

Design standards have improved over the years with stricter regulatory requirements and improvements in technology, but with the increased value at risk, loss statistics have also grown.

Data source

The Willis Energy Loss database is a compilation of offshore loss claims across each segment of the energy supply chain.

The database contains records beginning from the early 1970s covering nine regions of the world for insured losses greater than $1 million/occurrence. The manner in which data are aggregated and classified is determined in part by the manner in which claims reports are collected and user preference.

Categories reflect a limited number of causal choices but can also be

TOTAL OFFSHORE LOSSES BY REGION THROUGH 2004

Table 1

Region	First record	Incidents	Total loss (Million $)	Average loss (Million $)
Africa	1972	251	2,482	9.9
Australasia	1973	77	972	12.6
Caribbean	1973	25	235	9.4
Eastern Europe	1976	19	155	8.1
Europe	1972	997	11,169	11.2
Far East	1970	349	3,622	10.4
Middle East	1972	132	1,594	12.1
North America	1972	1,014	11,915	11.8
South America	1974	135	1,805	13.4
Total		**2,999**	**33,949**	**11.3**

NUMBER OF INCIDENTS AND TOTAL LOSSES BY REGION AND LOSS CATEGORY THROUGH 2004

Table 2

Region	FPSO*	FSU	Pipeline	Platform	Rig	SBM	SC	Vessel	Well	Total
Africa	10	3	68	51	42	10	18	12	37	251
Australasia	7	1	20	29	8	2	1	2	6	77
Caribbean	0	0	3	6	4	0	1	8	3	25
Eastern Europe	0	0	3	2	8	0	0	0	6	19
Europe	46	10	259	353	79	38	127	14	68	997
Far East	14	4	76	77	69	21	7	16	65	349
Middle East	1	1	30	35	29	4	2	14	15	132
North America	11	0	143	243	183	3	7	58	365	1,014
South America	11	0	31	24	46	2	1	6	13	135
Total	**100**	**19**	**633**	**820**	**469**	**80**	**164**	**130**	**578**	**2,999**
Total loss, billion $	1.1	0.3	3.9	13.4	7.1	0.5	0.8	1.2	5.7	33.9
Average loss, million $	11.3	14.2	6.1	16.3	15.1	6.5	4.9	9.4	9.9	11.3

*FPSO = floating production, storage, and off-loading unit; FSU = floating storage unit; SBM = single-point buoy mooring; SC= subsea completion.

NUMBER OF INCIDENTS AND TOTAL LOSSES BY REGION AND CAUSE THROUGH 2004

Table 3

Cause	Africa	Australasia	Caribbean	Eastern Europe	Europe	Far East	Middle East	North America	South America	Total
Anchor/jacking/trawl	32	7	2	0	56	18	12	46	6	179
Blowout	31	6	5	6	34	73	18	354	13	540
Capsize	0	0	0	0	0	0	0	3	3	6
Collision	11	3	2	0	21	9	17	31	1	95
Corrosion	0	2	0	0	13	0	2	5	2	24
Design/workmanship	29	17	1	2	354	48	15	63	12	541
Fire/lightning/explosion	17	1	3	3	46	12	8	55	11	156
Grounding	1	0	2	1	5	2	2	4	0	17
Heavy weather	13	3	1	1	66	34	12	58	14	202
Ice/snow/freeze	1	0	0	0	3	0	1	3	0	8
Impact	14	3	0	0	52	7	4	24	6	110
Leg punch through	4	1	0	0	2	9	4	18	2	40
Mechanical failure	25	6	1	3	54	25	5	46	21	186
Piling operations	4	4	1	0	10	12	2	8	3	44
Pipelaying/trenching	8	0	1	1	43	14	3	21	6	97
Stuck drillstem	5	1	0	0	10	2	0	12	3	33
Subsidence/landslide	0	0	0	0	4	2	0	4	0	10
Windstorm	1	5	0	0	0	18	0	174	0	198
Unknown	51	18	6	2	220	63	24	83	28	595
Total	**251**	**77**	**25**	**19**	**997**	**349**	**132**	**1,014**	**135**	**2,999**
Total loss, billion $	2.5	1.0	0.2	0.2	11.2	3.6	1.6	12.0	1.8	33.9
Average loss, million $	9.9	12.6	9.4	8.1	11.2	10.4	12.1	11.8	13.4	11.3

TOTAL LOSSES BY REGION AND LOSS CATEGORY THROUGH 2004

Table 4

Region	FPSO*	FSU	Pipeline	Platform	Rig	SBM	SC	Vessel	Well
					Million $				
Africa	37.2	13.3	348.1	880.1	668.6	50.7	68.4	141.5	273.5
Australasia	50.5	2.2	126.7	589.2	128.0	9.4	1.4	32.3	29.2
Caribbean	0	0	41.0	25.1	37.9	0	12.7	111.5	6.5
Eastern Europe	0	0	22.7	23.8	58.5	0	0	0	49.6
Europe	376.2	219.3	1,902.2	5,726.0	865.6	352.0	657.3	56.4	1,008.1
Far East	69.7	30.1	432.4	694.0	1,414.7	93.0	18.7	146.9	722.8
Middle East	1..1	4.6	110.9	379.8	680.0	6.6	5.4	66.1	337.5
North America	32.4	0	714.4	4,353.3	2,923.5	4.1	28.7	637.7	3,217.9
South America	558.7	0	165.7	678.4	315.5	5.5	3.1	28.8	49.0
Total	**1,126**	**270**	**3,864**	**13,350**	**7,092**	**521**	**796**	**1,221**	**5,694**

*FPSO = floating production, storage, and off-loading unit; FSU = floating storage unit; SBM = single-point buoy mooring, SC = subsea completion.

AVERAGE LOSSES BY REGION AND LOSS CATEGORY THROUGH 2004

Table 5

Region	FPSO*	FSU	Pipeline	Platform	Rig	SBM	SC	Vessel	Well
					Million $				
Africa	3.7	4.4	5.1	17.3	15.9	5.1	3.8	11.8	7.4
Australasia	7.2	2.2	6.3	20.3	16.0	4.7	1.4	16.1	4.9
Caribbean	0	0	13.7	4.2	9.5	0	12.7	13.9	2.2
Eastern Europe	0	0	7.6	11.9	7.3	0	0	0	8.3
Europe	8.2	21.9	7.3	16.2	11.0	9.3	5.2	4.0	14.7
Far East	5.0	7.5	5.7	9.0	20.5	4.4	2.7	9.2	11.1
Middle East	1.1	4.6	3.7	10.9	23.4	1.7	2.7	4.7	22.5
North America	2.9	0	5.0	17.9	16.0	1.4	4.1	11.0	8.8
South America	50.8	0	5.3	28.3	6.7	2.8	3.1	4.8	3.8
Average	**11.3**	**14.2**	**6.1**	**16.3**	**15.1**	**6.5**	**4.9**	**9.4**	**9.9**

*FPSO = floating production, storage, and off-loading unit; FSU = floating storage unit; SBM = single-point buoy mooring, SC = subsea completion.

misleading, since damage can occur in many forms and failures are often due to a combination of conditions.

Total offshore losses

For each offshore region of the world, overall losses are tabulated in terms of their inflation-adjusted total loss and average indexed loss (Table 1).

North America, Europe, and the Far East have the greatest number of incidents and offshore losses in the world, contributing roughly 80% of the total $34 billion reported loss.

The number of incidents is a useful measure to gauge the frequency of events and the relative size of each data category. On an aggregate basis, the average loss across all cause and loss categories are roughly comparable, ranging from $8.1 million (Eastern Europe) to $13.4 million (South America).

OFFSHORE LOSSES BY CAUSE—NORTH AMERICA, 1974-2000

Table 6

Cause	Frequency, %	Total loss, Million $	Average loss, Million $
Blowout	35	4,337	12.3
Windstorm	17	3,162	17.0
Design/workmanship	6	379	6.1
Heavy weather	6	759	13.3
Fire/lightning/explosion	6	1,144	20.8
Mechanical failure	5	460	10.2
Anchor/jacking/trawl	4	238	5.5
Collision	3	185	6.3

OFFSHORE LOSSES BY CAUSE—EUROPE, 1974-2000

Table 7

Cause	Frequency, %	Total loss, Million $	Average loss, Million $
Design/workmanship	35	3,778	10.7
Heavy weather	7	817	12.0
Mechanical failure	6	449	8.0
Anchor/jacking/trawl	6	304	5.4
Impact	5	242	4.7
Fire/lightning/explosion	5	2,286	46.7
Pipelaying/trenching	4	283	6.4
Blowout	4	826	20.7

Incidents by loss category

Platforms ($13.4 billion), rigs ($7.1 billion), wells ($5.7 billion), and pipelines ($3.9 billion) dominate the total loss category and contribute more than 80% of the total loss (Table 2).

Average platform ($16.3 million) and rig ($15.1 million) loss are more significant than the average well ($9.9 million) and pipeline ($6.1 million) damage.

Incidents by cause

With respect to the number of incidents and total losses by region and cause, categories with less than five total events are omitted here (Table 3).

The number of losses due to unknown causes is relatively small for North America (83 incidents, $413 million total loss, $5 million average loss) and the Far East (61 incidents, $261 million total loss, $4.3 million average loss), but significantly larger for Europe (222 incidents, $1.743 billion total loss, $7.9 million average loss).

Losses by loss category

The magnitude of losses provides an indication of the absolute losses, but for comparative analysis, the average loss is a more useful statistic (Tables 4 and 5).

South America, for example, exhibits the greatest average platform loss ($28.3 million), followed by Australasia ($20.3 million), North America ($17.9 million), Africa ($17.3 million), and Europe ($16.2 million). Regions such as the Caribbean and the Far East have low average platform losses.

Losses by cause

Offshore losses by cause for North America, Europe, and the Far East represent 80% of the total number of events for each region (Tables 6-8).

In North America, blowouts are the most frequent cause of loss, followed by windstorm, design/workmanship problems, heavy

OFFSHORE LOSSES BY CAUSE—FAR EAST, 1974-2000

Table 8

Cause	Frequency, %	Total loss, Million $	Average loss, Million $
Blowout	21	1,263	17.3
Design/workmanship	13	294	6.4
Heavy weather	10	287	8.4
Mechanical failure	7	109	4.5
Windstorm	5	456	25.3
Anchor/jacking/trawl	5	50	2.8

NUMBER OF OFFSHORE BLOWOUT EVENTS BY REGION AND LOSS CATEGORY

Table 9

Region	Platform	Rig	Well	OEE*	Total loss, Million $	Avg. loss
Africa	1	7	23	423	596	19.2
Australasia	1	1	4	57	63	10.5
Caribbean	0	2	3	6	21	4.1
Eastern Europe	0	0	6	37	50	8.3
Europe	0	3	31	729	826	31.1
Far East	3	16	54	927	1,263	17.3
Middle East	0	5	12	566	689	38.3
North America	8	21	324	3,212	4,346	12.3
South America	1	3	9	438	474	36.5
Total loss, million $	917	2,503	4,845	6,595	8,277	15.3
Average loss, million $	65.5	43.2	10.4	–	–	–

*Operators extra expense (OEE) includes the cost to control a blowout and the costs to redrill the well.

AVERAGE BLOWOUT LOSS BY REGION AND LOSS CATEGORY

Table 10

Region	Platform, Avg. loss, million $	Rig, Avg. loss, million $	Well, Avg. loss, million $
Africa	1.2	54.8	9.2
Australasia	28.2	15.1	5.0
Caribbean	0	7.1	2.2
Eastern Europe	0	0	8.3
Europe	0	53.4	19.9
Far East	23.3	36.8	11.2
Middle East	0	70.6	27.7
North America	51.7	45.4	9.2
South America	404.5	11.8	3.8
Average	**65.5**	**43.2**	**10.4**

NUMBER OF ONSHORE BLOWOUT EVENTS BY REGION AND LOSS CATEGORY

Table 11

Region	Rig	Well	Total loss, Million $	Average loss, Million $
Africa	0	14	180	12.8
Australasia	0	3	33	11.1
Caribbean	1	1	17	8.3
Eastern Europe	0	1	3	2.9
Europe	0	7	205	29.2
Far East	3	22	178	7.1
Middle East	5	4	106	11.8
North America	22	575	2,984	5.0
South America	5	51	386	6.9
Total loss	**440**	**3,653**	**4,093**	**5.7**
Average loss	12.2	5.4	—	—

BLOWOUT EVENTS BY TOTAL DEPTH—NORTH AMERICA, FAR EAST, EUROPE

Table 12

Region	North America			Far East			Europe		
Depth, ft	Incidents	Total loss Million $	Avg. loss Million $	Incidents	Total loss Million $	Avg. loss Million $	Incidents	Total loss Million $	Avg. loss Million $
0-4,999	19	168	8.8	9	130	14.4	12	156	13.0
5,000-7,499	20	198	9.9	12	258	21.5	1	2	2.0
7,500-9,999	44	200	4.5	6	102	17.0	1	4	4.0
10,000-14,999	114	780	6.8	5	87	17.4	8	69	8.6
15,000-19,999	40	586	14.7	1	59	59.0	6	411	68.5
20,000	5	160	32.0	0	0	0	0	0	0
TBA	112	1,120	10.0	40	291	7.3	12	88	7.3
Total	**354**	**3,211**	**9.1**	**73**	**927**	**12.7**	**40**	**729**	**18.2**

NUMBER OF INCIDENTS OF FIRE EVENTS BY REGION AND LOSS CATEGORY THROUGH 2004

Table 13

Region	FPSO*	FSU	Pipeline	Platform	Rig	SBM	Vessel	Total loss Million $	Avg. loss Million $
Africa	0	0	0	13	2	1	1	174.7	10.3
Australasia	0	0	0	1	0	0	0	6.5	6.5
Caribbean	0	0	0	2	1	0	0	15.7	5.2
Eastern Europe	0	0	0	0	3	0	0	28.1	9.3
Europe	1	1	0	36	6	1	1	2,257.9	49.1
Far East	1	0	0	9	2	0	0	163.2	13.6
Middle East	0	0	0	4	2	0	2	66.8	8.3
North America	1	0	1	26	18	0	9	1,143.6	20.8
South America	1	0	0	4	4	0	2	744.7	66.7
Total	**4**	**1**	**1**	**95**	**38**	**2**	**15**	**4,590.2**	**29.4**
Total loss, million $	553	1,091	1,547	3,450	359	45	80	—	—
Average loss, million $	138	1,091	1,547	36.3	9.5	22.4	12.0	—	—

*FPSO = floating production, storage, and off-loading unit; FSU = floating storage unit; SBM = single-point buoy mooring.

NUMBER OF INCIDENTS OF DESIGN/WORKMANSHIP EVENTS BY REGION AND LOSS CATEGORY THROUGH 2004

Table 14

Region	FPSO*	FSU	Pipeline	Platform	Rig	SBM	SC	Vessel	Well	Total loss Million $	Avg. loss Million $
Africa	4	1	6	6	4	2	3	1	2	150.0	7.2
Australasia	3	1	7	5	1	0	0	0	0	167.3	9.8
Caribbean	0	0	0	1	0	0	0	0	0	12.1	12.1
Eastern Europe	0	0	0	1	1	0	0	0	0	25.3	12.7
Europe	22	4	83	143	2	12	70	2	5	3,764.7	10.6
Far East	7	1	13	15	4	3	1	1	3	297.1	6.2
Middle East	0	0	2	6	2	1	1	1	2	53.1	3.5
North America	6	0	11	25	12	0	2	3	4	389.1	6.2
South America	4	0	2	4	1	1	0	0	0	41.1	3.4
Total	**46**	**7**	**124**	**206**	**37**	**19**	**77**	**8**	**16**	**4,899.8**	**9.1**
Total loss, million $	343	57	1,022	2,455	229	140	400	57	195	—	—
Average loss, million $	7.4	8.2	8.2	11.9	6.2	7.4	5.2	7.1	12.2	—	—

*FPSO = floating production, storage, and off-loading unit; FSU = floating storage unit; SBM = single-point buoy mooring; SC = subsea completion.

weather, fire/lightning/explosion, and mechanical failure (Table 6). The relative frequency indicates the number of events relative to the total that occurred over the time period in which loss reports were available.

On average, the most expensive incidents are fires ($20.8 million), followed by windstorms ($17 million), heavy weather ($13.3 million), blowouts ($12.3 million), and mechanical failure ($10.2 million).

Fire and windstorms often represent the largest loss by cause because of the total destructive nature. Fire and windstorms require topsides and structural replacement. Blowouts, windstorms, and fire represent 75% of the total indexed losses reported.

In Europe, design/workmanship incidents occur most frequently, followed by heavy weather, mechanical failure, anchor/jacket/trawl, and pipelaying/trenching problems (Table 7).

Similar to North America, fire events represent the largest average loss ($46.7 million) but at a substantially higher average level. Following fire events are blowouts ($20.7 million), heavy weather ($12.0 million), and design/workmanship ($10.7 million).

Because the average value of a platform in the North Sea is many times greater than an average Gulf of Mexico platform, when a fire occurs it is expected to be more destructive. Design/workmanship, fire, blowouts, and heavy weather contribute about three-fourths of the total indexed losses.

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European blowouts are more costly than North American blowouts, but the impact of heavy weather losses are roughly comparable. North America and European losses reflect differences in the environmental conditions and the design requirements for offshore production.

In the Far East, blowouts are the most frequent loss occurrence, similar to North America, followed by design/workmanship, heavy weather, and mechanical failure (Table 8). Windstorms lead to the largest average loss ($25.3 million), followed by blowouts ($17.3 million) and heavy weather ($8.4 million). It is interesting to note that fire/lightning/explosion events in the Far East are not a major contributor to losses.

Blowout events

Total losses from blowouts include the direct physical loss or damage to platforms, rigs, and equipment (Table 9).

Operators extra expense (OEE) includes the cost to control a blowout and the cost to redrill the well. North America is responsible for more than half of the total losses reported. The Middle East and South America exhibit average losses nearly $38 million/blowout, while the Caribbean, Eastern Europe, and Australasia exhibit average aggregate losses in the range $4-10 million.

Average and total loss

North America exhibits an average $9 million/blowout, while the Far East has a $37 million average rig blowout cost (Table 10).

Note that in several regions a small sample size may prevent the average statistic from being representative of the region. Most blowouts occur in exploratory drilling, but platform blowouts, which primarily represent development wells, are also common. Loss reports do not allow well blowouts to be assigned to drilling, production, or workover activity, and the occurrence of drilling vessel blowouts is small.

The average loss due to a platform blowout is significantly larger than a rig blowout, probably reflecting the higher valuation and potential damage associated with the platform. The average well blowout loss claim is $10.4 million.

Onshore blowouts

Sample sizes for most regions are relatively small, but for North America, South America, and the Far East, the data are sufficiently large to conclude that onshore blowouts are typically two to five times less costly than their offshore counterparts (Table 11).

Blowouts by TD

There is no apparent trend in average loss with total drilling depth in North America, the Far East, and Europe, although North American losses tend to be lower on average than other regions (Table 12).

Fire/lightning/explosion

Europe and North America dominate offshore fire losses, but relative to the total onshore loss ($38.762 billion), the offshore total is relatively small (Table 13).

Platforms ($3.450 billion), FPSOs ($553 million), and rigs ($359 million) comprise the major elements. Floating storage units and pipelines statistics are skewed probably because of the sample size.

Design/workmanship events

Europe dominates design/workmanship problems ($3.765 billion), far exceeding North America ($389 million) and the Far East ($297 million) (Table 14).

This is partly explained by the hostile operating environment in the North Sea, where platforms need to be built to withstand the harsh conditions. Platforms and pipelines contribute the greatest amount to the loss categories, and on average, the loss statistics are roughly comparable across each category.

Next: How weather affects offshore energy losses. ✦

Spain

Sherritt International Corp., Toronto, is awaiting final regulatory approval to begin work on four blocks in the Alboran Sea off southern Spain.

The company was awarded permits in March 2007 to explore the blocks, which total 818,261 acres. Planned work includes a 3D seismic survey and contingent wells.

Oregon

Torrent Energy Corp., Portland, Ore., determined that 580 bcf of coalbed methane should be commercially producible from its Coos Bay basin CBM project using a 4,000-ft depth cutoff.

This volume is 50% of the identifiable CBM resource. The company, which owns an 83.5% net revenue interest in the project, expects to receive a gas price in excess of the posted New York Mercantile Exchange gas price index.

The determination came after permeability at the Westport pilot program was found to average 8 md and range from 4 to 15 md. This is similar to values in the Raton, Appalachian, and Uinta basins, Torrent said.

Work will resume at the Radio Hill and Beaver Hill pilots after pipeline infrastructure reaches the areas, the company said.

Wyoming

Response to carbon dioxide flooding is strong in giant Salt Creek field, where the part of the field under an enhanced oil recovery project set a production record of 5,200 b/d of oil equivalent in the quarter ended Mar. 31, said Anadarko Petroleum Corp., Houston.

The field surpassed 3 million bbl of cumulative production due to EOR in the quarter. A 200 MMcfd CO_2 recycling compression station was to start up in the ensuing quarter.

Elsewhere, the Monell field CO_2 project hit record output of 3,500 boed, and a 20 MMcfd natural gas liquids extraction plant was nearly completed.

Floating production expanding rapidly

James R. McCaul
International Maritime Associates Inc.
Washington, DC

During the last year, the world has seen a 10% increase in the number of operating floating production systems.

Currently 197 floating production systems are operating worldwide. Another 62 systems are on order for delivery within the next 3 years.

Also and most importantly, underlying market fundamentals have never been stronger because floating production is a development option being studied in more than 100 projects in the planning stages.

As a result, International Maritime Associates Inc. (IMA) has raised by 15% its 5-year forecast of production floater orders.

Production floaters

The current production floater inventory in operation has 118 floating production, storage, and offloading vessels (FPSOs); 40 production semi-submersibles; 20 tension-leg platforms (TLPs); 15 production spars; and 4 production barges (Fig. 1). These units produce fields primarily off West Africa, Northern Europe, US Gulf Coast, Brazil, Southeast Asia, China, Australia, and New Zealand.

Another 76 floating storage and offloading vessels (FSOs) are in service, primarily in Southeast Asia, West Africa, and the North Sea.

Leasing companies that charter the units to field operators and generally, but not always, provide operational services own about 40% of production and storage units in use. Field operators that either operate units with their own personnel or engage an operating-management company own the remaining 60%.

The mix of leased and owned units among different types of floating production systems varies considerably. About 50% of FPSOs and 60% of FSOs are leased, while only 15% of other production units are leased.

Strong market

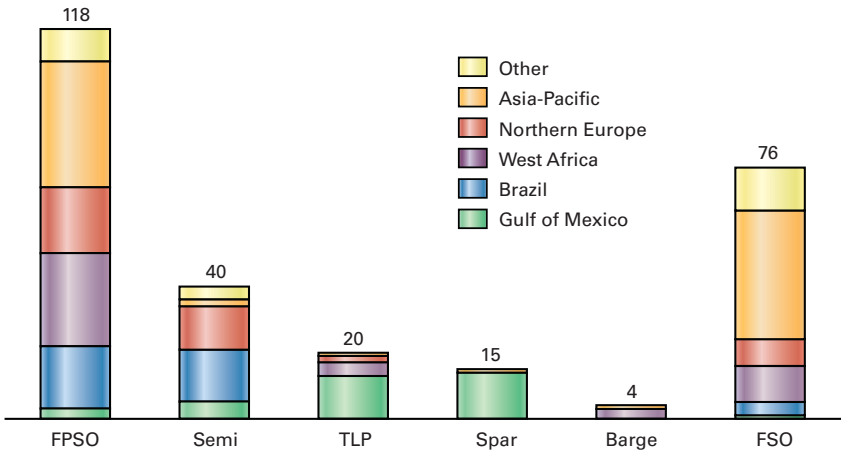
Fundamentals driving the floating production sector have never been stronger. Crude futures prices 6 years out are in the mid-$60/bbl range, and crude prices of $50/bbl or more have gained increased acceptance as the measure for project hurdles.

The lure of $60/bbl crude is drawing capital into the floating production sector. Industry has made speculative investment of more than $3 billion in a dozen production floaters now on order without field contracts.

Future offshore exploration and production activity is extremely positive. IMA expects capital budgets for exploration and production spending to increase 10-15% in 2007, with many companies earmarking deepwater as their spending priority.

Deepwater drilling rig demand is bursting at the seams, with rates for high specification floaters passing $500,000/day. These high rates have made building new rigs attractive; and therefore, drilling contractors will have available a surge of new deepwater drilling vessels during the next few

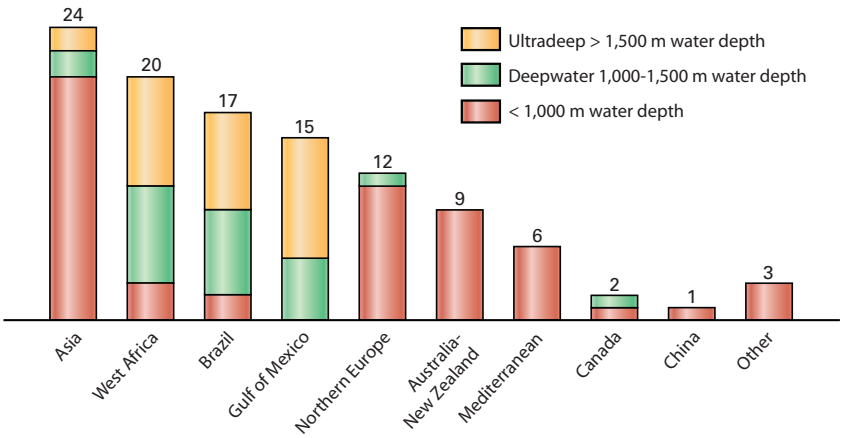
CURRENTLY OPERATING PRODUCTION, STORAGE FLOATERS Fig. 1



Source: IMA, Floating Production Systems, March 2007

PLANNED, UNDER STUDY FLOATER PROJECTS

Fig. 2



Source: IMA, Floating Production Systems, March 2007

years, eliminating some constraints on exploration and development that have slowed deepwater projects in recent years.

These indicators suggest that growth of floating production clearly has room to expand.

Planned projects

IMA's recently published study has identified 109 offshore projects in the planning pipeline that potentially require floating production systems (Fig. 2).

Asia has the largest concentration of new projects, with 24 known floater projects. Of these 14 are at bidding or final design stage.

West Africa has the second largest concentration of new projects, with 20 known projects in the planning pipeline, 8 of which are in bidding or final design stage.

In third place is Brazil with 17 projects, followed by the Gulf of Mexico with 15, Northern Europe with 12, and Australia-New Zealand with 9.

Redeployments

Redeploying existing units will satisfy an increasing portion of new floating production projects involving FPSOs.

During the past 5 years, 16 FPSO redeployments accounted for 17% of FPSO contracts. But as lease contracts expire and fields reach depletion, more units will become available and the percentage of FPSO contracts that use redeployed units will increase.

Of 60 leased FPSOs in service, 31 have contracts in which the firm lease period or known option period expires within the next 5 years. Some of these units will become available as current leases expire, although some will receive lease extensions.

More importantly, of 122 FPSOs (leased and owned) currently in operation, 58 have been on a field for more than 5 years and 20 for more than 10 years. Among the units that have operated for more than 5 years, 18 are high-end, well maintained, harsh environment FPSOs now in use in the North Sea.

The ability to redeploy existing units depends on numerous technical issues, such as compatibility of the old and new fields in terms of reservoir fluids, producing GOR, water depth, operating environment, and storage requirement.

Another complication is the extent to which single-hull FPSOs will be accepted for use on future fields. Less than 20% of the 58 units on fields more than 5 years have double hulls. The other 80% may find resistance to redeployment on fields in environmentally sensitive areas.

Also influencing redeployment is the economics of removing a unit from an existing field, even one that is handling small production volumes. Oil prices in the $60/bbl range have extended the economic limit of these fields and allow operators to keep producing them even at a very small percentage of the unit's processing capacity.

For example, the Jabiru Venture and Challis Venture FPSOs off Australia recently averaged 2,200 bo/d production, which is 4% of the installed processing capacity. Yet the units apparently remain profitable and will continue operating. In these cases, not only does the field continue to produce a positive cash flow but the operator defers abandonment costs.

IMA expects that redeployments will provide about 25% of the FPSOs needed for new projects during the next 5 years. ✦

The author

James R. McCaul (imaassoc @msn.com) is president of International Maritime Associates Inc. He established IMA in 1973. Before forming IMA, he was member of the faculty of Webb Institute of Naval Architecture. McCaul holds a PhD in economics from the University of Maryland, an MS in business administration from Pennsylvania State University, and a BS in marine science from the State University of New York.

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XTO Energy extends life of Arkansas wells

Al Hood
XTO Energy Inc.
Oklahoma City

Stephen Ingram
Joe Blakey
Halliburton Corp.
Oklahoma City

Philip Nguyen
Halliburton Corp.
Duncan, Okla.

In its production operations in northwest Arkansas, XTO Energy Inc. has extended the productive life of five gas wells by controlling proppant flowback. The flowback was plugging rod pump systems and eroding tubular goods.

XTO Energy is the largest natural gas producer in Arkansas, with more than 500,000 acres under lease. The company is following two trends in the Arkoma basin: Fairway trend and Overthrust trend, as well as the Fayetteville Shale. XTO is focusing on well recompletions and new stimulation techniques, as well as drilling additional development wells.

There were three rigs drilling in fourth-quarter 2006 and the company expects to drill 90-100 wells in the Arkoma basin in 2007. About 86% of Arkoma basin production is from Arkansas wells and about 14% from Oklahoma wells (www.xtoenergy.com).

In addition to the five gas wells discussed in this article, XTO has identified many more wells that would likely benefit from flowback control. Projected value added, in the form of reduced workover-cleanout expense and increased production from the five wells treated ranges from $210,000 to 440,000/well/year. Figs. 1 and 2 illustrate the economic impact of conducting cleanout operations to remove produced proppant from the near-wellbore area, tubulars, and production equipment at the surface.

Although flowback-control treatment may have minor effect on production rate in most cases, it helps greatly to keep the wells in continuous production, without requiring shutdown for workover and cleanout processes. In some wells, treatments have increased production substantially.

History

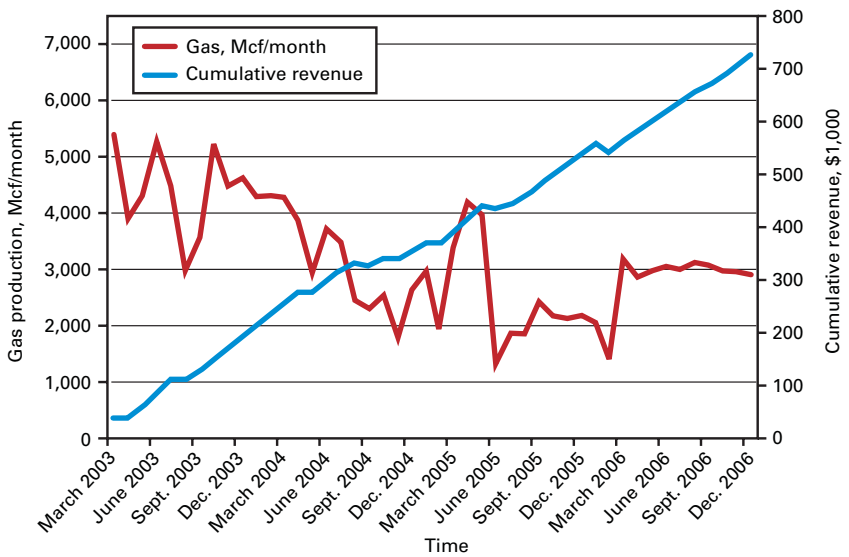
XTO wells in northwest Arkansas were typically drilled and completed in the late 1980s. Completion methods included: (1) perforation and (2) production without fracture stimulation or other production-enhancement measures. The pay zones in these vertical wells are at about 5,000 ft, and they have produced at commercially favorable levels.

In early 2003, XTO accelerated a fracture stimulation program that substantially increased natural gas production. XTO fractured existing producing zones, typically using a nitrified borate gel system to place 20/40-mesh sand. Production spiked up and then began to decline. In addition, proppant flowback accompanying the hydrocarbons fouled the rod-pump system.

In 2006, XTO treated five wells with a proppant-flowback arresting system (Fig. 3) that has (1) halted proppant

MONTHLY GAS PRODUCTION*

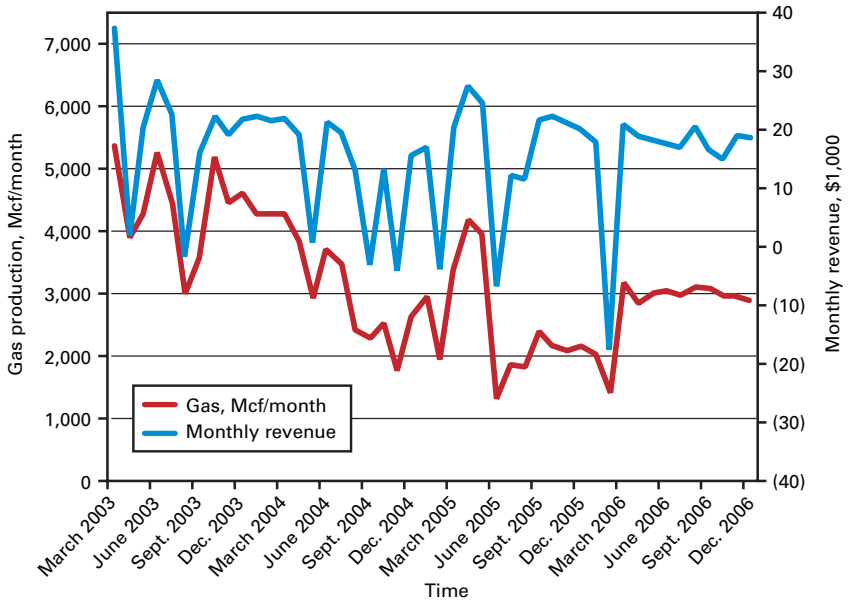
Fig. 1



*Note the several points of decline in monthly well production (red) when well cleanouts were performed. The cleanouts cost about $15,000 each. In February 2006, a combined cleanout and PFA treatment was performed at a cost of $28,000. No subsequent cleanouts have been necessary.

Monthly production, revenue*

Fig. 2



*Since the February 2006 cleanout and PFA treatment, production and revenue have been steady and without undue expense.

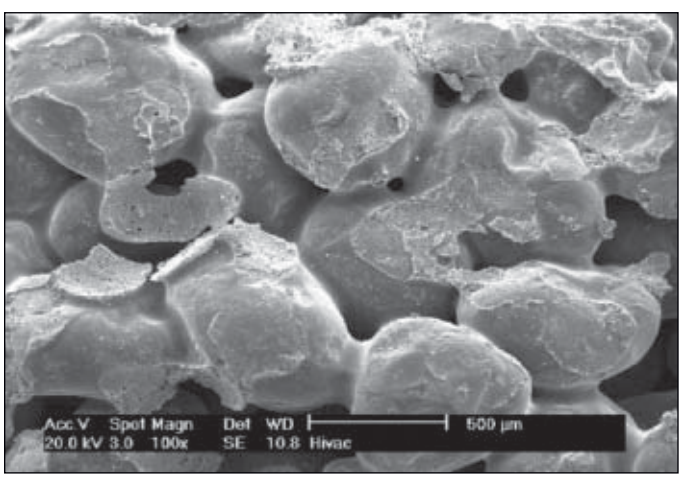
flowback, (2) prevented damage to the rod-pump systems, and (3) increased productivity. Conventional resin applied to the proppant pack, because of its high viscosity and ineffective displacement, can plug porosity of proppant pack, reducing the flow area available to produce hydrocarbons (Fig. 4).

Arresting flowback

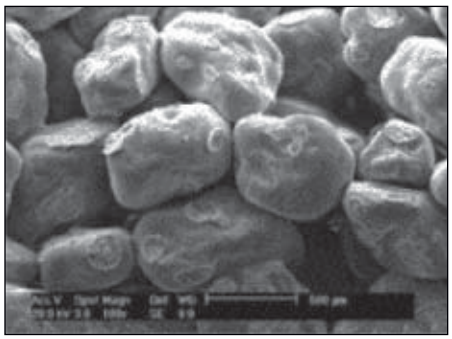
A proppant-flowback arrester (PFA) helps control proppant flowback and fines production and helps maintain highly conductive fractures and long-term productivity. The process is a proven remedy for the fundamental causes of a pervasive industry problem that escalates as production assets mature.

PFA is designed to help slow production decline often seen in fractured wells in mature assets. Proppant flowback and formation fines production cost operators millions of dollars annually in lost production and equipment damage. Wells experiencing these problems require remediation, ranging from routine wellbore cleanouts to complete workovers to expensive artificial-lift equipment repairs. Use of a PFA service addresses the problem with these features:

- Provides cohesion between proppant grains without damaging permeability or conductivity of proppant pack.
- Helps maintain highly conductive fractures and long-term productivity.
- Treats proppant pack with low-viscosity curable resin.
- Applied with pulsing action to enhance uniform placement of treatment fluids into propped intervals.



Conventional resin applied to the proppant pack can plug porosity, reducing the flow area available to produce hydrocarbons, as shown in this photomicrograph (Fig. 4).



The proppant in this photomicrograph is coated with PFA fluid, which is applied by pulsing or pressure-wave action. The process provides cohesion between the grains without damaging permeability or conductivity of the proppant pack (Fig. 3).

How PFA is used

PFA service combines new technologies that enable treatment of proppant after it has been placed in the fracture. The service uses coiled tubing coupled with either pressure-pulsing or fluid-wave technology, based on well requirements. PFA service is a coiled-tubing deployed, single-trip, rigless intervention service that requires no isolation packers, thus reducing time, cost, and risk of a conventional workover. This approach treats the existing proppant in the near-wellbore region of propped fractures to reduce or eliminate current and future proppant production and its related problems.

- *Consolidating systems.* The coating used in PFA service does not produce the high consolidation strength commonly required of a coating in an initial fracturing treatment but is adequate to lock the proppant into place. In addition, the treatment process clears fines and debris from the proppant pack placed near the perforations to help restore and maintain conductivity between fracture and wellbore.

After coating the surfaces of proppant grains, the consolidating agent forms

a tacky, thin film of resin that creates bonds between grains that cure with time and temperature. Unconsolidated proppant grains are consolidated with negligible loss of initial permeability.

The combination of resin with the activator into a single component helps ensure that wherever the proppant pack is treated, the consolidation will take place without the uncertainty that often accompanies other consolidation systems. Instead of an instant cure, as often occurs with acid catalysts, curing of the resin designed in this one-component system takes place slowly to allow complete placement into the proppant pack and complete displacement from the pore space within the proppant pack.

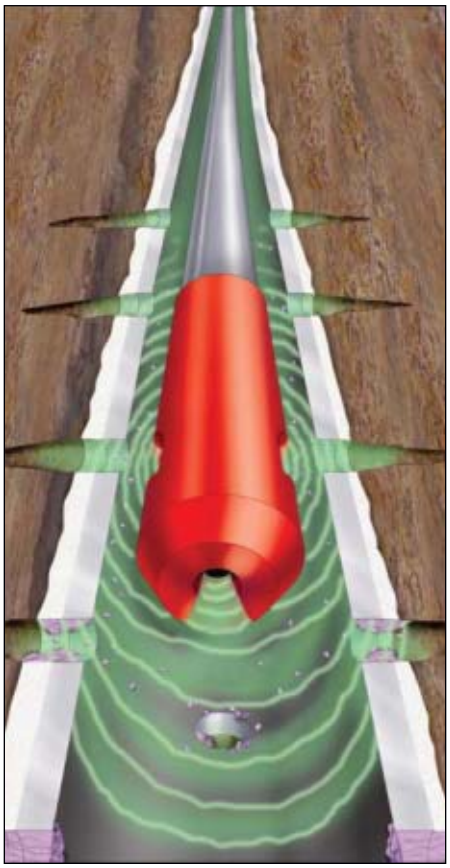
• *Pulsing tools.* PFA treatments can be applied with either fluid-oscillator technology or low-frequency pulsing; both methods enhance fluid flow through porous media (Fig. 5). Fluid oscillation produces emissions of alternating bursts of fluid that create pulsing pressure waves within the wellbore and formation fluids. These pressure waves can break up many types of near-wellbore damage, helping restore and enhance the permeability of the perforations and near-wellbore area.

Wave stimulation is a coiled-tubing deployed placement method for improving chemical treatments such as matrix acidizing, scale inhibition, and remedial sand-proppant control. The wave technology is based on high-amplitude, low-frequency pulsing (LFP) to enhance flow of fluids through porous media.

Its porosity-dilation effect results in fluids being forced into normally unoccupied pore spaces under the influence of pressure waves. The effect is more attributable to fluid-wave propagation and pore dilation than to rock movement.

PFA service provides the following technical and economic benefits:

- Extends production life of the well.
- Reduces proppant production.
- Reduces wear on surface equipment and tubulars.
- Reduces need for workovers and well cleanouts.
- Reduces damage to artificial-lift equipment.
- Can be placed into existing proppant packs.



PFA service is implemented with pulsing technology to help ensure penetration into the proppant pack. Based on well requirements, either fluidic oscillation (FO) or high-amplitude, low-frequency pulsing is used to enhance fluid flow through porous media. The FO pressure waves can break up many types of near-wellbore damage. The LFP effect results in fluids being forced into normally unoccupied pore spaces under the influence of pressure waves (Fig. 5).

PFA service procedure

PFA treatments applied to five wells are described below. Procedures followed on two wells are detailed; similar procedures were followed for all five wells.

Case 1

This well was identified for treatment because it required cleanout to remove proppant every 3 months, requiring a workover rig. The source of the proppant was a fracture treatment performed in 2003 to increase production that had declined to marginal levels. Typical cleanout costs are $3,000/day for the workover rig, with 4 lost-production days associated with the process. Cleanout costs range between $18,000 and $44,000.

The PFA treatment was performed on two zones, both on the same day, in 6 hr of pumping. Between proppant-con-

The authors

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ditioning flushes and chemical spacers, 75-gal batches of resin were pumped down 2⅜-in. jointed tubing with a local workover rig to reciprocate the tubing across each perforated interval.

A pulse-pressure tool was applied across the perforated intervals to enhance fluid flow into the proppant porosity. The pulsing technique eliminated the need for mechanical isolation between intervals. Pumping rate was 1 bbl/min. No proppant flowback has been observed during the year of production since the treatment.

Case 2

This well was completed in 1986 and produced naturally until 2003, when it was fractured with a borate-cross linked gel and 75,000 lb of 20/40 white sand, at 1 to 5 lb/gal. Initial proppant-sand production reduced rod-pump system efficiencies, leading to costly workover completions and nonproductive time.

The PFA treatment was conducted in much the same manner as described in Case 1. Since the treatment, no proppant has been produced and the pumping system continues to run smoothly. Economically viable production levels have been restored. ✦

Study outlines European refinery demand to 2015

A recent study of the European refining industry from Concawe (Conservation of Clean Air and Water in Europe) concludes that the imbalance between demand for gasoline and middle distillates will continue to increase. The study, "Oil refining in the EU in 2015," developed base case, low-demand, and other plausible supply-demand scenarios to evaluate possible consequences in terms of investment requirements, total economic impact, energy consumption, and CO_2 emissions.

From a reference 2015 scenario, Concawe explored different sensitivities, which included such factors as the dieselization rate of EU's car population, improved vehicle efficiency, effects of nontechnical measures to reduce demand, introduction of biofuels, and availability of gasoline export markets and gas oil/diesel import sources.

The study's main conclusions are:

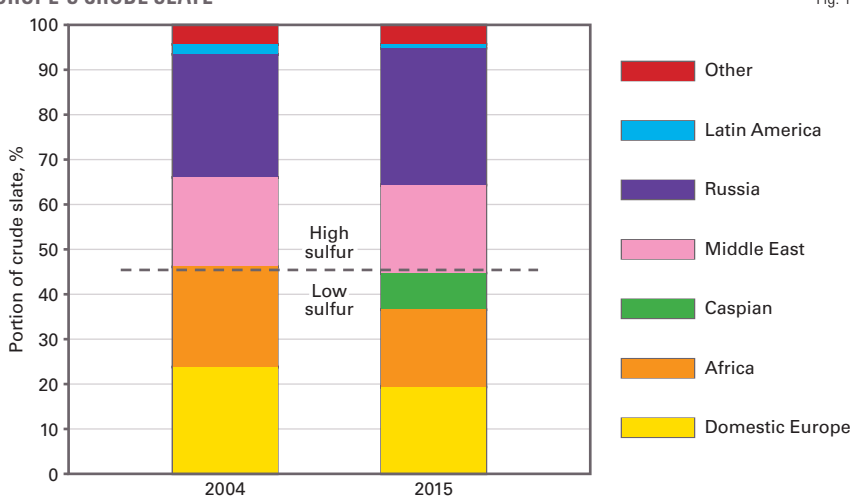
- Adequate crude distillation capacity exists in Europe to meet forecast demand by 2015. Refiners there, however, must add downstream units and operate others differently to cope with changes in the product slate, especially regarding middle distillates and gasoline.
- The gas-oil-to-gasoline (GO/G) ratio is the most important parameter that determines the processing configuration that will be needed. This ratio, according to Concawe, can change due to many factors including dieselization, relative penetration of alternative fuels, and continued availability of gasoline export markets and middle distillate imports.
- Refinery investments are mainly required in hydrocracking and some residue desulfurization or conversion capacity.
- A continued increase in the GO/G ratio would present serious difficulties for EU refiners in terms of adapting their refineries for the right processes and the magnitude of required investments.
- A possible increase in overall CO_2 emissions due to an excessive rate of dieselization and a decrease in the efficiency gas between diesel and gasoline cars.

EU refinery model

The Concawe study used a linear programming technique to simulate the European refining system. The EU, plus Norway and Switzerland, was divided into eight regions: Baltic, Benelux, Germany, Central Europe, UK and Ireland, France, Iberia, and Mediterranean. In

EUROPE'S CRUDE SLATE

Fig. 1



each region, the actual refining capacity was aggregated for each process unit into a single notional refinery.

Six model crudes represented crude feeds to the region's refineries. Specific other feedstocks could also be included in the model.

The model was first calibrated with real data from the 2005 base year. The 2015 scenarios were then run as independent cases.

As a rule, Concawe required the model to produce the stipulated demand from a given crude slate; the main flexibilities were crude allocated to each region, intermediate and finished product exchanges, and mainly investment in new process units. The crude diet was the same in all cases (45% light low sulfur, 55% heavy high sulfur) with only one crude (heavy Middle East) allowed to vary.

Crude supply

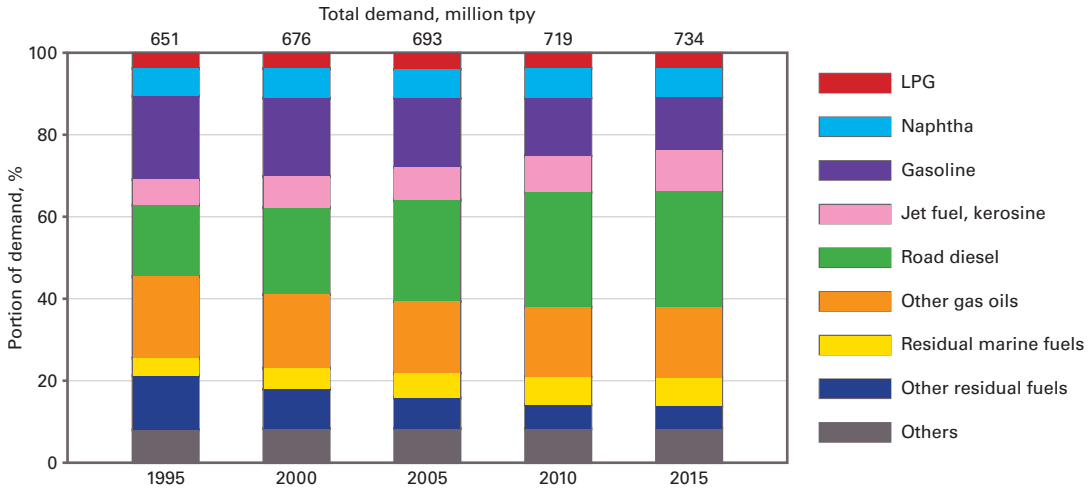
In the past 2-3 decades, the favorable geographic location of Europe in relation to light and sweet crude-producing regions has resulted in a fairly light crude diet, according to the study.

In 2005, the 27 countries included in the study consumed about 735 million tonnes of crude as feedstocks. This will grow to 785 million tonnes by 2015, according to Concawe.

Supplies will be adequate for this demand, but supply sources will change. North Sea production will decline but other regions like West Africa and Caspian basin will take over. This change will not significantly affect overall quality; the study predicts that Europe will be able to maintain its current proportion of 45% sweet crude feed (Fig. 1).

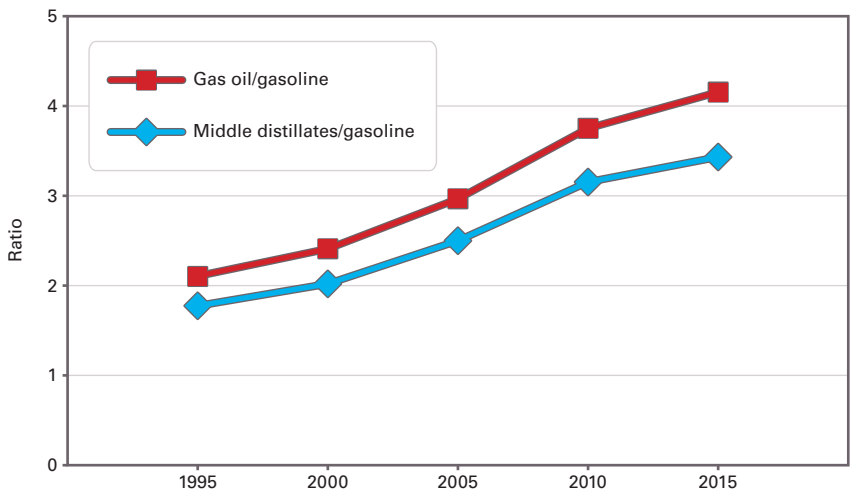
EUROPEAN PRODUCT DEMAND

Fig. 2



PRODUCT RATIOS

Fig. 3



Product demand

Europe, in the past few years, has seen two main trends affecting product demand from its refineries:

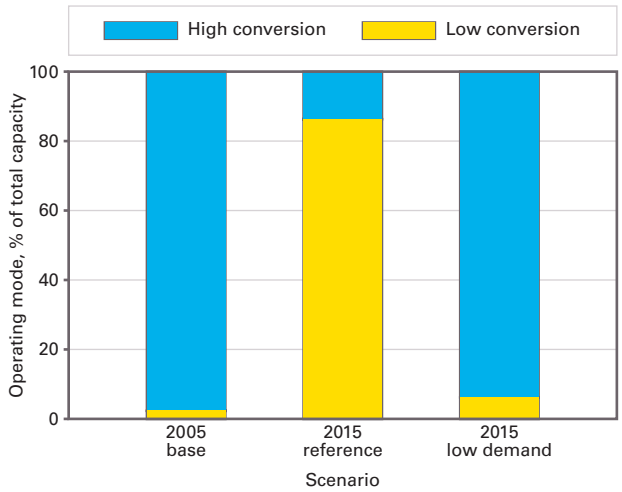
- Lighter products. Europe is demanding more gas oils and lighter products, and less residual fuel oils. This is due to development of land and air transport as well as demand for petrochemical feedstocks.
- Dieselization. Europe has a fast-growing market for diesel and jet fuel, and eroding demand for gasoline. Although present in other regions of the world, this trend is particularly strong in Europe.

Fig. 2 shows historical demand for various refinery products and the forecast to 2015. It shows the further lightening of the demand barrel. The widening imbalance between middle distillates (gas oils, kerosine, jet fuel) and gasoline is also obvious; a marked decrease of gasoline demand and large increases of diesel and jet fuel demands only slightly tempered by a slow decline of other gas oils (mostly heating oil).

Fig. 3 shows imbalances in the GO/G ratio and middle-distillate-to-gasoline ratio. In this study, gas oils include automotive, marine, and off-road diesel,

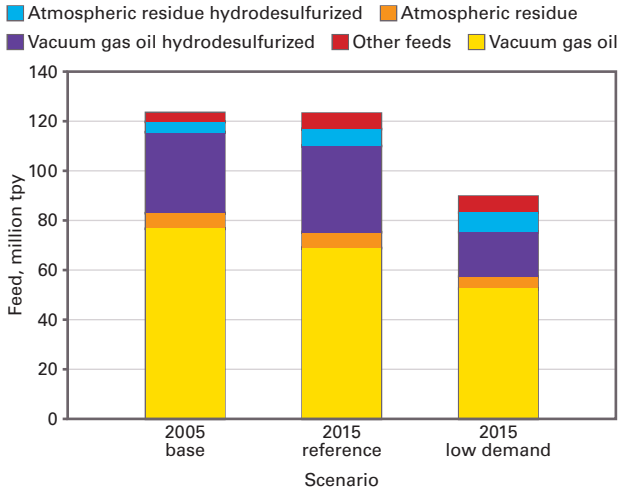
FCC OPERATING MODE

Fig. 4



FCC FEED COMPOSITION

Fig. 5



REFERENCE, LOW-DEMAND SCENARIOS

Table 1

	Gasoline	Road diesel: Total	Road diesel: To cars	Road diesel: To freight	Nonroad diesel	Total diesel	Other gas oils	Gas oil/ gasoline ratio
	Volume, million tpy							
Reference scenario								
Net demand	96.8	206.8	68.8	138.0	30.0	236.8	96.9	3.4
Low demand scenario								
Car efficiency improvements plus dieselization	–13.8	6.2	6.2					
Other policies and measures	–10.0	–23.0	–9.0	–14.0				
Net demand	73.0	190.0						
Impact of biofuels	–11.0	–9.0						
Net demand	**62.0**	**181.0**			**30.0**	**211.0**	**96.9**	**5.0**
External trade								
Exports	21.9							
Imports						–10.3	–10.0	
Net refinery demand								
Reference scenario	**118.7**					**313.4**		**2.6**
Low-demand scenario	**83.9**					**287.6**		**3.4**

heating gas oils, and industrial gas oils. Middle distillates also includes jet fuel and kerosine.

Fig. 3 shows that the GO/G ratio has increased 50% since 1995 and will increase another 50% by 2015.

Refinery requirements

To study refinery requirements, Concawe first forecast total market demand and then made assumptions of the proportion of that demand that EU refineries will have to meet. There are two main sources of discrepancy between demand and refinery requirements.

The first source is trade. The imbalance between middle distillates and gasolines has made it virtually impossible to meet these two demands simultaneously without reverting to trade, according to the study. European refiners have been able to balance demand and supply by exporting surpluses of gasoline (mostly to the US) and importing gas oils and jet fuel (from Russia and the Middle East). European refiners depend heavily on the continued availability of these export markets and import sources.

Based on the most recent International Energy Agency final statistics (2003), Concawe assumed 2005 trade flows were:

- 28 million tonnes/year (tpy) of middle distillate imports (10 million tpy of finished road diesel, 10 million tpy of heating oil, and 8 million tpy of jet fuel).
- 22 million tpy of gasoline exports. The 2003 gasoline export figure was lower, but, in view of the fast reducing gasoline market Concawe assumed the 2005 figures would be higher.

In the reference scenario, the study assumed that these current trade levels are carried forward into the future.

The second source of discrepancy between demand and refinery requirements is the substitution of refined products by alternative fuels. The study's reference scenario does not include any provision of biofuels or other alternatives.

Factors affecting demand

The study found that many factors affect refined product demand:

- Automobile fuel efficiency.
- Dieselization.
- Other technical and nontechnical measures to reduce transportation demand or improve efficiency.

All these factors will likely lead to less, rather than more, demand for refinery investments; therefore, Con-

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cawe developed a low-fuel-demand scenario based on an analysis of plausible evolution of these factors (Table 1).

Currently, every other car sold in the EU has a diesel engine; diesel cars represent about 30% of the total fleet. If diesel vehicle sales remain at their current level, its share will increase to more than 40% in 2015.

The study's reference scenario assumes about 35% diesel cars in the fleet by 2015, which implies a reduction of the fraction of new sales. There is, therefore, considerable scope for scenarios that foresee higher diesel penetration.

For the low-demand scenario, Concawe assumed diesel sales increasing to 60% of all new cars by 2015. This roughly corresponds to a shift of 8 million tpy of refined product demand from gasoline to diesel. For the extreme scenarios, the study considered a maximum of 75% diesel sales in 2020.

It is of course also plausible to envision a reversal of the trend towards diesel cars. Concawe therefore considered an extreme case in which diesel sales would slump to 20% of the total by 2015 and stay constant thereafter.

Technical measures include efficiency improvements of other road vehicles (particularly trucks), low-friction lubricants, low-friction tires, driver feedback systems, and improved traffic-flow management.

EU REFINING IN 2015

Table 2

	2005 base	2015 Reference	2015 Low demand
Total production, million tpy	**645.2**	**699.4**	**638.2**
Fraction of light products, %[1]	83.0	83.2	81.6
Production ratios			
Diesel/gasoline	1.2	1.8	2.3
Gas oil/gasoline	2.0	2.6	3.4
Middle distillates/ gasoline	2.3	3.2	4.2
Existing and new process plant capacity utilization, million tpy			
Crude atmospheric distillation	678	747	679
Vacuum distillation	260	284	264
Visbreaking	71	83	69
FCC	123	123	90
Hydrocracking	77	108	116
Resid desulfurization	11	15	18
Reformate splitting	27	47	38
Aromatics extraction	9	11	8
PP splitting	4	5	5
Middle distillate hydrotreating	214	260	232
Hydrogen, 1,000 tpy	796	1,244	1,169
Steam cracker	66	77	81

Investment in new process plants		**Capacity, million tonnes**			**Capacity, million tonnes**		
Capacity			**% of existing**			**% of existing**	
Crude atmospheric distillation		68.2	10		20.3	3	
Vacuum distillation		23.9	9		8.0	3	
Visbreaking		12.5	18		2.0	3	
Hydrocracking		31.2	40		46.1	60	
Residual desulfurization		4.3	39		7.0	63	
Reformate splitting		20.1	73		12.0	44	
Aromatics extraction		2.5	28		2.3	26	
Propane-propylene splitting		1.7	43		1.4	35	
Kerosine hydrotrating		5.9	14		5.0	12	
Gas oil HDS (revamp)		30.2	21		14.6	10	
Gas oil HDS (new)		10.0	7		3.1	2	
Hydrogen, 1,000 tpy		463	58		463	58	
Steam cracker		10.8	16		15.1	23	
	Total	**Total**	**Refining**	**Petchem**	**Total**	**Refining**	**Petchem**
Capital cost, billion €		15.2	12.9	2.2	16.6	13.2	3.4
Total annual cost,[2] billion €		4.4			3.2		
Energy consumption, 10^{15} J/year	1,965	2,176	1,920	256	1,962	1,699	263
% of total production	7.25	7.41			7.32		
CO_2 emissions, million tpy	136.7	156.4	141.3	15.1	138.0	122.5	15.5
tonne/tonne of total production	0.212	0.224			0.216		

[1]Gas oils and lighter, including petrochemicals. [2]Excluding margin effects.

Nontechnical measures include taxation, eco-driving (with voluntary or mandatory training), energy labeling, speed limits, etc.

Investment requirements

In the study's low-demand scenario, curtailment of the road-fuel market leads to less total product demand by 2015. In this scenario, Europe will not require new crude distillation capacity; any marginal increases will be due to minor revamps of existing units and capacity creep.

Relative demand for refined products will, however, evolve markedly. This study focuses on the possible evolution of transportation fuel demand and, more specifically, to how much EU refineries will have to produce, including the share of biofuels and the scope of external trade.

These changes in the demand barrel will require refiners to adapt their plants to make these products from available crude oil supplies. In practice, this means modified and new plants and, therefore, investments. Within the highly complex and flexible EU refining system, supply-demand constraints can also be alleviated, at a cost, by intra-European trade of either finished products or intermediate streams.

Although Concawe does constrain

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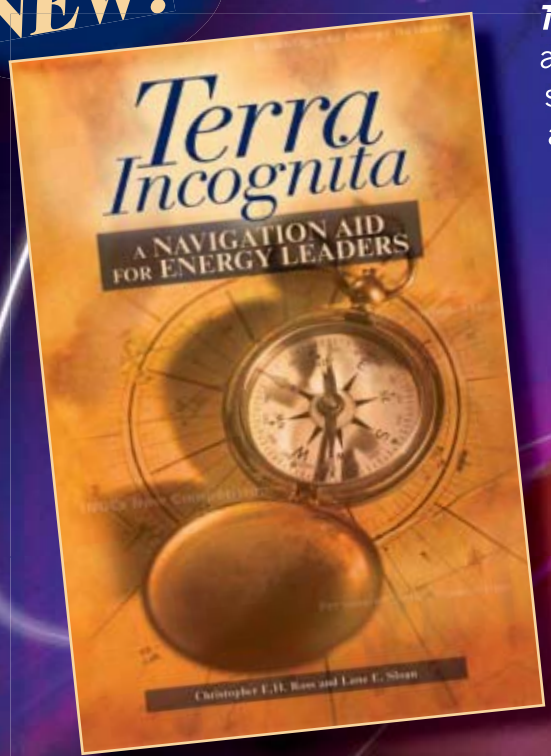

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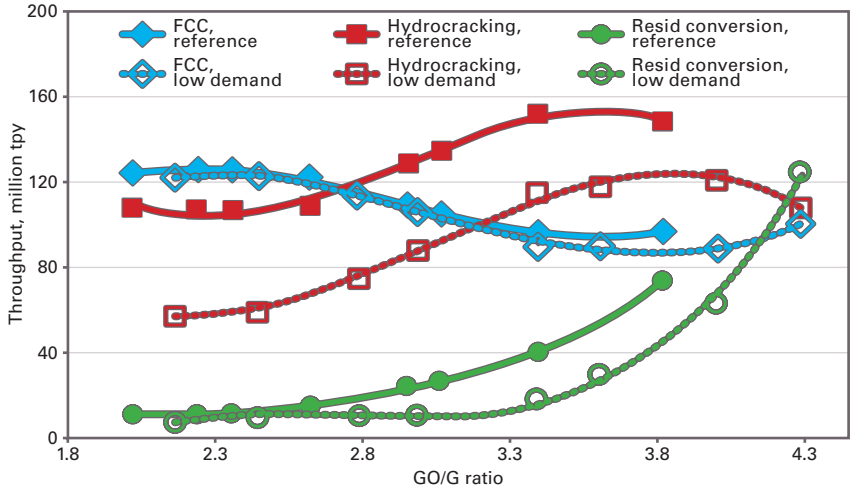
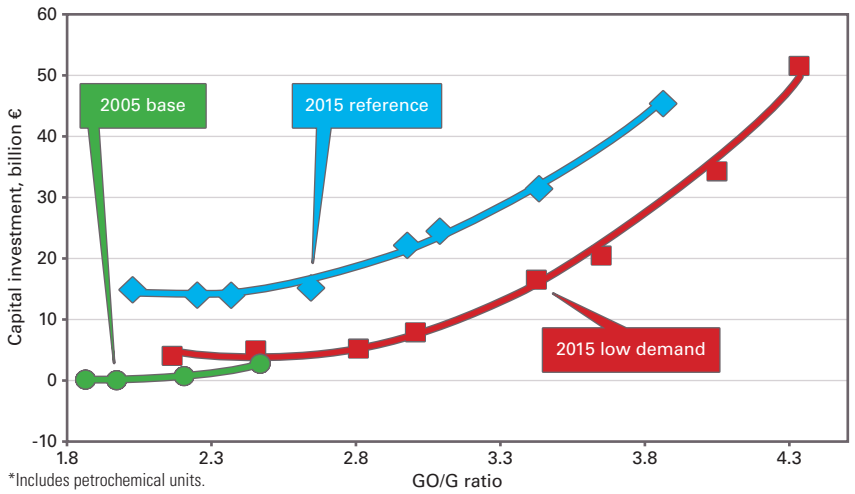
Fig. 6



CAPITAL INVESTMENT IN NEW REFINERY UNITS*

Fig. 7



*Includes petrochemical units.

the internal trade opportunities to what appears feasible logistically, the modeling represents an economic optimization of the system's capabilities.

Table 2 summarizes the changes to the EU refining system required by 2015 for both the reference and low-demand scenarios.

Reference scenario

Total production increases 8.5% in the reference scenario. This will require more distillation capacity, although this level of increase is attainable via capacity creep through minor revamps rather than new units or grassroots refineries.

The fraction of light products in the total product slate (which characterizes conversion intensity) only increases marginally; demand for residual does decrease, but current residual fuel oil imports (around 10 million tpy) are assumed to cease by 2015.

Production of an additional 47 million tpy of distillates requires, however, new conversion capacity. Because the bulk of the increase is in the form of diesel and jet fuel, hydrocracking is the preferred route. The model also seeks to maximize the economic use of existing assets. FCCs are still fully used, but their operating mode changes (Fig. 4).

In the 2005 base case, almost all FCC capacity operates as high-conversion units, thereby maximizing the yield of gasoline components and minimizing the yield of low-quality diesel components. In the 2015 reference scenario, FCCs operate as low-conversion units. Light cycle oil quality improves, partly due to use of hydrotreated feedstocks from dedicated feed hydrotreaters, mild hydrocrackers, and residue desulfurizers (Fig. 5) but also by deep hydrodesulfurization.

Additional deep gas-oil hydrodesulfurization is also required to make sulfur-free road diesel. There is of course a concurrent need for extra hydrogen production.

A significant increase of reformate splitting is required to rebalance the various quality requirements of the gasoline pool.

According to the study, any additional steam cracker capacity is broadly in line with increased ethylene demand. The larger increase in demand for higher olefins and aromatics is partially met in refineries that will invest in propane-propylene splitter and aromatic extraction plants. Steam-cracker feed composition only marginally changes.

The resulting capital investment cost is €15.2 billion (€4.4 billion/year), which includes capital charges, extra fixed and variable costs, and extra fuel and loss. All these additional plants consume energy and energy consumption of the refineries goes up in absolute terms, as do CO_2 emissions.

Energy consumption and CO_2 emissions also increase relative to the total production. Because the depth of conversion does not significantly change, this is clearly the result of a higher GO/G ratio.

Low-demand scenario

Reduced transportation-fuel demand results in a slight contraction of the total refinery output, according to the study's low-demand scenario. Because the study assumes that demand for all other products is constant, the conversion intensity is lowered.

The middle distillate/gasoline ratio is, however, nearly double compared to the 2005 base case. Refiners can only achieve this level of production via a much larger shift from FCC to hydrocracking capacity. Utilization of existing FCCs is much lower (72% of available capacity), whereas investment in new hydrocracking and residue desulfurization capacity is 50% higher than in the reference scenario despite reduced conversion intensity.

The mechanisms used by the model to rebalance the gasoline pool are complex.

In this scenario, FCCs operate in high-conversion mode (Fig. 4) and more desulfurized residue is used as FCC feed (Fig. 5), replacing desulfurized vacuum gas oil used as hydrocracker feed.

The steam-cracker feed diet changes significantly; more heavy naphtha is used because less gasoline, no hydrowax, and less LPG is produced in refineries due to lower FCC runs. The average ethylene yield decreases compared to the base case, which explains the additional increase in steam cracker feed capacity compared to the reference scenario.

For energy consumption and CO_2 emissions, both effects compensate each other so that the figures are similar to the study's 2005 base case.

Sensitivity to GO/G ratio

Fig. 6 shows the changes in the cumulative throughputs of key process plants. Similar to what was observed in the comparison between the reference and low-demand scenarios, FCC utilization decreases with increasing GO/G ratio. Concurrently, new hydrocracking and residue desulfurization capacity becomes important. At very high ratios, hydrocracking cannot be further increased due to a lack of feedstock and massive residue desulfurization capacity is the only solution. FCC throughput recovers somewhat because more desulfurized residue feedstock becomes available.

The large investment cost required to install additional unit capacity correlates remarkably well with the GO/G ratio for a given level of demand (Fig. 7). Both curves follow the same trend. The reference scenario requires €15.2 billion of investment (from the 2005 base case) and increasing the GO/G ratio from 2.6 to 3.4 virtually doubles this cost.

Fig. 7 shows a shallow minimum towards the lower range of GO/G ratios. This suggests there may be an optimum ratio value, as a function of the demand level, where demand can be met at lowest investment cost. ✦

Model studies thermal effects of liquid pipeline colocation

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Beijing

Changes in the vertical relative position of two liquids pipelines laid in the same trench (one crude, one products) produce only small changes in the temperature of the crude oil, allowing this approach to be used as a viable alternative to dual trenching. Small buried delocalization is acceptable and the relative position of the two pipelines can be determined by the small thermal change which occurs.

This article uses a numeric model based on China's West Pipeline to demonstrate the viability of pipeline colocation.

West Pipeline

China saved money and minimized environmental damage during the 2005 construction of the West Pipeline by laying several hundred kilometers of crude and products pipelines in the same ditch. This technique required a specific thermal analysis of the interaction between the two pipelines.

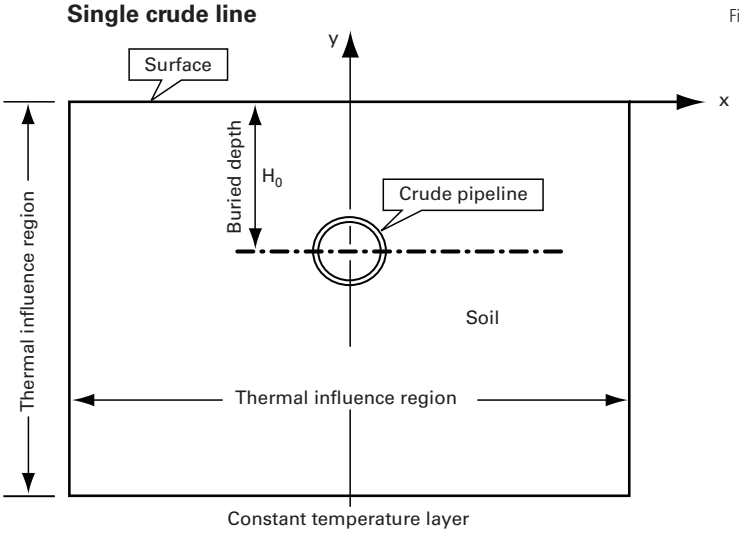
Most crudes China produces are

Buried pipelines

Fig. 1

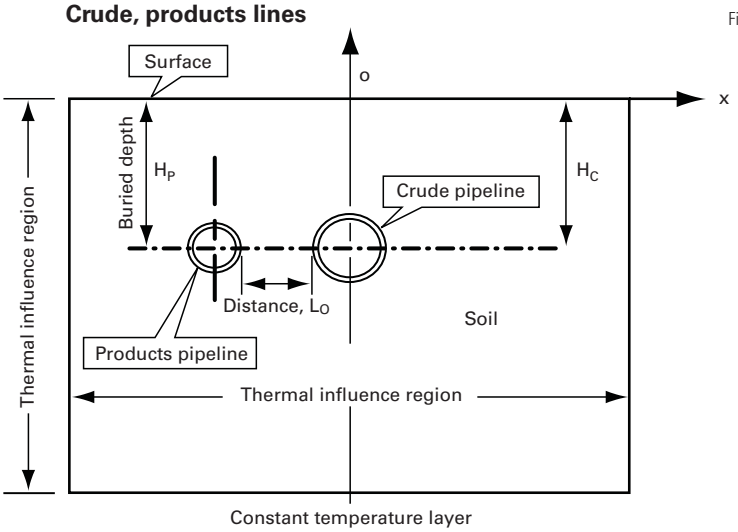
Single crude line

Fig. 1a



Crude, products lines

Fig. 1b

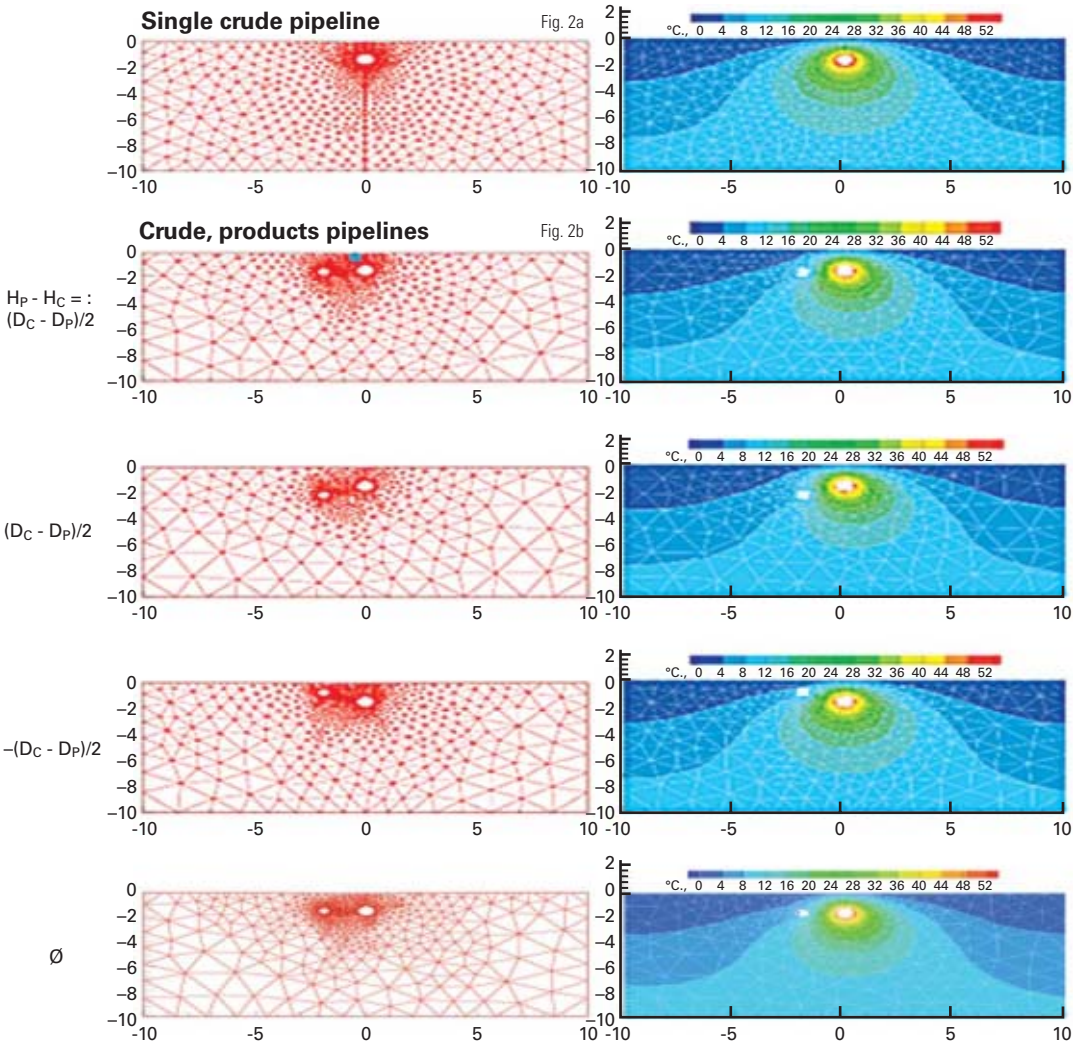


either waxy with high pour points or viscous and heavy. Poor flow properties call for heating the crude oil, and temperature along the pipeline is a key variable.[1-2] The products pipeline may absorb heat from the crude pipeline, thereby lowering the crude's temperature. Avoiding crude oil gel required study of this problem.

The interval between the two pipelines affects the heat transfer between them. Detailed thermal analyses studied the effect of the interval on temperature of the crude oil, finding that when the pipeline interval is larger than 1.2 m, the temperature decrease of the crude oil is acceptable.

STATION OUTLET CALCULATION DOMAINS, SOIL TEMPERATURE FIELDS

Fig. 2



The calculations, however, assumed that the axes of the double pipelines were on the same horizontal plane (Fig. 1). Though this is an ideal condition, construction cannot guarantee it. Changes in the heat transfer with variation of the relative vertical position of the two pipelines stand as another important issue in the thermal analysis.

This article uses a numerical method to study this issue.

The numerical calculation used the same pipe used for the West Pipeline—813 mm OD, 11-mm WT crude oil line, 559 mm OD, 7-mm WT products line—and set the distance between them at 1.2 m. The study also used the physical properties of North Xinjiang crude oil and 90-octane gasoline.

Researchers set the buried depth of the crude oil pipeline at a constant of H_c = 1.6 m and used Equation 1 (see accompanying box) to set the buried depth of the products pipeline and determine relative vertical position, thereby determining the effect of the vertical relative position of the two pipelines (Fig. 1).

D_c and D_p represent the ODs of the crude oil pipeline and the products pipeline, respectively. The last two buried depths of the products pipeline are

PIPELINE PARAMETERS

Table 1

	Length, km	Temperature, buried depth, °	Throughput, 10^4 tonnes/year	Outlet temperature, °	Wax deposition, mm	Corrosion protective covering, mm
Crude oil	240	1.6	1,000	60	8	8
Products	240	–	800	5	–	8

Equations

$$H_p = H_c, H_p = H_c + (D_c - D_p)/2, H_p = H_c + (D_c + D_p)/2 \text{ and } H_p = H_c - (D_c + D_p)/2 \quad (1)$$

$$g \sin\alpha + \frac{1}{\rho}\frac{\partial p}{\partial z} + \frac{f}{D}\frac{V^2}{2} = 0 \quad (2)$$

$$C_p \frac{dT}{d\tau} - \frac{T}{\rho}\beta\frac{dp}{d\tau} - \frac{fV^3}{2D} = -\frac{4q}{\rho D} \quad (3)$$

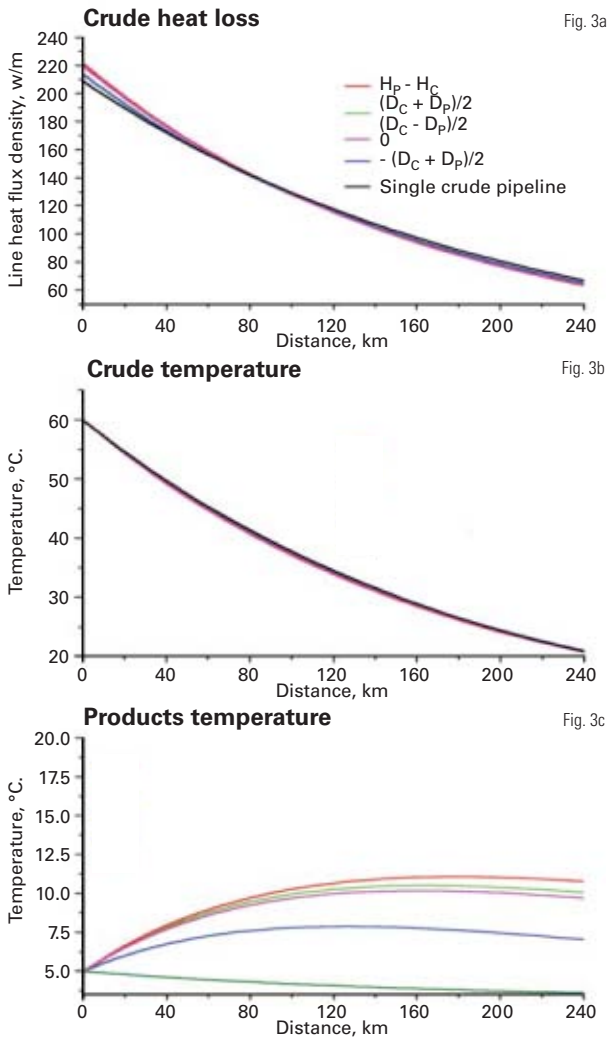
$$\rho C_p \frac{\partial T}{\partial \tau} = \frac{1}{r}\frac{\partial}{\partial r}(\lambda r \frac{\partial T}{\partial r}) + \frac{1}{r^2}\frac{\partial}{\partial \theta}(\lambda \frac{\partial T}{\partial \theta}) \quad (4)$$

$$\rho C_p \frac{\partial T}{\partial \tau} = \frac{\partial}{\partial x}(\lambda \frac{\partial T}{\partial x}) + \frac{\partial}{\partial y}(\lambda \frac{\partial T}{\partial y}) \quad (5)$$

Where:
z, D, τ, α, and β represent the axial position of the pipeline, the inner diameter, time, angle between the axis of the pipeline, and the horizontal line and expansion coefficient of oil, respectively; V and q represent the average velocity of the oil flow and the heat flux density, respectively; and ρ, C_p, T, and λ, respectively, stand for the density, heat capacity, temperature, and thermal conductivity.

Temperature dynamics, relative vertical positions

Fig. 3



not be realistic and were included so that the actual pipeline depth could be intervenient.

Table 1 shows other parameters of the study.

Calculations of a single crude oil pipeline and single products pipeline under the same conditions as the dual line provide a point of comparison (Fig. 1).

Mathematical model

Assumptions made in the mathematical model include:[3]

- Uniformity of temperature of crude oil and products on the same pipeline cross-section; i.e., the temperatures of the crude and the products lines are a function of time and axial location of the pipeline.
- Simplification of the soil anisotropy outside the pipelines as isotropy.
- Simplification of three-dimensional unsteady heat conduction outside the pipes as two-dimensional unsteady heat conduction; neglecting the axial heat conduction.
- Selection of the thermal influence region of the crude oil pipeline as the computational domain, the ranges of which are $-10 \text{ m} \le x \le 10 \text{ m}$ and $-10 \text{ m} \le y \le 10 \text{ m}$ (Fig. 1). The temperature of the soil 10 m down from the ground surface is constant; 10 m away from the crude oil pipeline is the heat-insulating boundary.

The hydraulic gradient and oil heat transfer in steady operation using these assumptions yield Equations 2 and 3.

Equations 4 and 5 show the heat conductive equation of wax deposition, pipe wall, and corrosion protective covering under a polar coordinate system, and the heat conductive equation of the soil under a Cartesian coordinate system.

Maximum temperature difference (T_{DIFF})

Table 2

	$(D_c+D_p)/2$	$(D_c-D_p)/2$	0	$-(D_c+D_p)/2$
Crude, °C.	0.6	0.6	0.6	0.2
Location, km	94	88	84	74
Products, °C.	7.3	6.7	6.3	3.9
Location, km	198	184	180	152

Results, analysis

The left column of Fig. 2 shows the grid generation of the soil's computational domain when the axes of the pipelines are not on the same horizontal plane, while the right column shows the soil temperature field at the pumping station's outlet.

The soil temperature fields on the right side of the crude oil pipeline are basically the same, meaning the effect of the products pipeline on the

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soil temperature field is minor. Similar conclusions emerge at different pipeline distances.

The isothermals on the left side of the crude oil pipeline changed greatly with variation of the vertical relative position of the two pipelines. The heat loss of the hot crude oil pipeline at the pumping station outlet increased due to the heat absorption of the products pipeline. Moreover, as the products pipeline's buried depth increased, the heat loss of the crude oil also experienced a small increase. The vertical relative position of the two pipelines did not significantly affect heat loss on the crude oil.

Analysis showed that when there are two pipelines in one ditch, the heat loss of the crude oil pipeline is greater than that of the crude oil pipeline laid in a ditch on its own at distances less than 80-100 km and is smaller than that of the single crude oil pipeline at distances greater than 80-100 km. Across the first 80-100 km, the significant temperature difference between the hot crude oil and the cold products increases the products temperature and decreases the crude oil temperature. After 80-100 km have been traveled, the heat absorption of the products pipeline diminishes and the products even release heat due to the minor temperature difference between the two pipelines.

Fig. 3c shows that the temperature of the products first increases then decreases. Fig. 3b and Fig. 3c show the temperatures of the crude and products separately. Table 2 details the underlying data.

A new parameter, T_{diff}, describes the thermal effect on the crude oil pipeline clearly. The parameter consists of the temperature difference at the same location of a pipeline coexisting with another and one laid on its own. Fig. 3b, in which the curves have good superposition with each other, shows that T_{diff} of the crude oil is minor when the vertical relative positions of the two pipelines change.

The maximum T_{diff} of the crude oil and products lines both decrease gradually with the shallower buried depth of the products pipeline (Table 2). Table 2 also shows the maximum T_{diff} and its location.

Changing the physical properties of the soil, the outlet temperature, and the throughput rates of crude oil and the products had little effect on the results. The comparison described here varied the depth of the products pipeline while keeping the crude oil pipeline fixed. Reversing these conditions would produce similar results.

Acknowledgment

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Laser system detects gas pipeline leaks

An airborne gas pipeline leak detection system combines a methane sensitive laser with a digital video record of the pipeline.

Test findings revealed by the Rocky Mountain Oilfield Testing Center, Casper, Wyo., from results of a study conducted by the US Department of Energy evaluating the use of Englewood, Colo.-based Aviation Technology Services' proprietary laser leak detection system indicate that ATS's system found 25% more leaks on a blind test than any other system tested and detected 90% of all gas released in the test. Aerial, laser leak detection is a fast method of inspection without losing pipeline production, ATS notes.

During 4 days in September 2006, RMOTC evaluated ATS's Boreal laser system for natural gas leak detection near Casper. Throughout the test, ATS's helicopter-based laser system consistently detected methane leaks, the firm reports. Large and small leaks were successfully detected, measured, and reported, ATS points out.

Source: **Aviation Technology Services**, 7355 S. Peoria St., Suite 112, Hangar 10 South, Englewood, CO 80112.

Two new fishing tools on the market

The Superior hydraulic fishing jar (tool on the left in the photo) and Superior energizer are new to the market.

The jar is a straight pull, up-only tool that utilizes a special valve section to meter oil from one chamber of the piston to the other chamber to allow controlled jarring action during a stuck fish recovery. The operating chambers are sealed and isolated from each other to prevent contamination of the metering section and the well. During downhole jarring operation, jarring blow is infinitely adjustable without any rig floor adjustments necessary prior to the run. The straight pull load applied by the operator controls the intensity of the jarring blow—a light pull load delivers a light blow, while a heavier pull load delivers a heavier blow. Pull load is simply varied to change the jarring blow.

When maximum jarring impact and impulse are needed, particularly in shallow, deviated, or directional holes where acceleration and effectiveness of movement is diminished, a Superior energizer is run in conjunction with a jar of corresponding size. The energizer is essentially a fluid spring that stores energy when strain is applied to the fishing string. It offsets the loss of stretch or drag on the running string and provides a means to store required energy immediately above the drill collars and the fishing jar to increase the amount of impact energy. Use of an energizer allows the use of fewer drill collars than would otherwise be possible, the firm says.

Source: **Logan Oil Tools Inc.**, 11006 Lucerne St., Houston, TX 77016.

Technip

Paris, has named Guy Arlette as president of operations and to the group's executive committee, replacing Daniel Burlin, who has retired.

Arlette, a graduate of Paris' Ecole des Mines, was head of the oil and gas directorate for the French Ministry of Industry, as well as working for several major energy firms, before joining Technip 15 years ago.

Technip is among the top five providers of oil, gas, and petrochemical engineering, construction, and services. In support of its activities, the group manufactures flexible pipes and umbilicals, and builds offshore platforms.

Varel International

Dallas, announced further expansion with the opening of a Rocky Mountain regional office in Denver. Jim Dahlem has been hired as regional sales manager to head up that office. Dahlem, a 30-year oil and gas industry veteran, previously held positions with Security DBS. He earned BA and BS degrees in chemistry and Russian from the University of Colorado, and an MBA from Stephen F. Austin State University in Texas.

Varel International is a large global supplier of oil and gas drill bits. The company employs 1,000 people and has manufacturing facilities in Texas, Mexico, and France.

DNV

Columbus, Ohio, has announced the establishment of the Material and Corrosion Research Center in Columbus, in cooperation with Ohio State University and CC Technologies. The center will develop new technology and methodologies related to material corrosion.

Narasi Sridhar will serve as manager of the center. Sridhar is a recognized expert in corrosion research and development, and comes to the position from the Southwest Research Institute in San Antonio, Tex.

Neil Thompson, founder of CC Technologies and global onshore pipeline director of DNV Energy, has directed the development of the research center.

DNV is an independent foundation, and a leading international provider of risk management services. It has a staff of 7,000 operating from more than 300 offices worldwide.

Baker Hughes Inc.

Houston, has announced the appointment of Stephen K. Ellison as president of Baker Atlas and vice-president of Baker Hughes Inc.

Ellison, who holds a bachelor's degree in physics from Oxford University, joined Baker Atlas in 1979. He most recently served as vice-president, Baker Atlas Middle East and Asia Pacific.

Baker Hughes Inc. is a leading provider of drilling, formation evaluation, completion, and production products and services to the worldwide oil and gas industry.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	5-4 2007	[1]4-27 2007	5-4 2007	[1]4-27 2007	5-4 2007	[1]4-27 2007	5-5 2006
	1,000 b/d						
Total motor gasoline	479	404	7	5	486	409	489
Mo. gas. blending comp.	692	565	122	43	814	608	1,149
Distillate[2]	261	205	102	17	363	222	416
Residual	350	290	34	28	384	318	529
Jet fuel-kerosine	144	56	194	64	338	120	253
LPG	230	254	6	5	236	259	255
Unfinished oils	545	587	5	9	550	596	345
Other	382	324	70	4	452	328	512
Total products	**3,038**	**2,685**	**540**	**175**	**3,623**	**2,860**	**3,948**
Canadian crude	1,462	1,699	103	141	1,565	1,840	1,903
Other foreign	7,868	7,723	1,305	893	9,173	8,616	7,778
Total crude	**9,330**	**9,422**	**1,408**	**1,034**	**10,738**	**10,456**	**9,681**
Total crude	**12,413**	**12,107**	**1,948**	**1,209**	**14,361**	**13,316**	**13,629**

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

PURVIN & GERTZ LNG NETBACKS—MAY 4, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.94	4.82	6.16	4.73	5.39	6.14
Everett	6.46	4.41	6.09	4.51	4.97	6.75
Isle of Grain	1.95	0.12	1.41	0.03	0.61	1.47
Lake Charles	5.37	3.50	5.12	3.66	3.92	5.97
Sodegaura	4.45	6.36	4.66	6.20	5.57	3.97
Zeebrugge	5.58	3.65	5.04	3.57	4.18	5.05

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel Kerosine	Fuel oils		Unfinished oils
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD I	15,212	53,104	26,170	9,213	41,579	14,921	7,054
PADD II	76,161	46,970	16,273	6,901	29,683	1,281	14,909
PADD III	184,534	64,019	25,865	13,975	32,310	16,644	46,693
PADD IV	13,738	5,746	1,623	545	3,158	256	3,134
PADD V	[1]55,133	29,391	19,816	9,051	12,322	5,677	23,744
May 4, 2007	**[1]344,778**	**199,230**	**89,747**	**39,685**	**119,052**	**38,779**	**95,534**
Apr. 27, 2007[3]	**343,807**	**198,293**	**90,966**	**39,644**	**119,678**	**39,466**	**93,213**
May 5, 2006	**347,962**	**207,449**	**90,536**	**41,605**	**116,459**	**41,325**	**94,165**

[1]Included in total motor gasoline. [2]Includes 5.195 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAY 4, 2007

District	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,521	1,483	1,486	1,618	91.8	1,884	80	538	141
App. Dist. 1	73	66	68	95	71.6	85	0	15	0
Dist. 1 total	**3,594**	**1,549**	**1,554**	**1,713**	**90.7**	**1,969**	**80**	**553**	**141**
Ind., Ill., Ky.	2,045	1,918	1,933	2,355	82.1	1,283	107	610	66
Minn., Wis., Dak.	396	391	394	442	89.1	372	22	131	11
Okla., Kan., Mo.	793	630	631	786	80.3	546	20	251	4
Dist. 2 total	**3,234**	**2,939**	**2,958**	**3,583**	**82.6**	**2,201**	**149**	**992**	**81**
Inland Texas	917	625	644	647	99.5	397	43	158	7
Texas Gulf Coast	3,742	3,216	3,316	4,031	82.3	1,377	333	876	142
La. Gulf Coast	3,544	3,190	3,200	3,264	98.0	1,256	386	869	176
N. La. and Ark.	224	185	185	215	86.1	69	13	51	7
New Mexico	151	105	105	113	92.9	121	4	39	1
Dist. 3 total	**8,578**	**7,321**	**7,450**	**8,270**	**90.1**	**3,220**	**779**	**1,993**	**333**
Dist. 4 total	**666**	**512**	**515**	**596**	**86.4**	**165**	**31**	**153**	**13**
Dist. 5 total	**2,785**	**2,502**	**2,750**	**3,173**	**86.7**	**1,539**	**354**	**550**	**121**
May 4, 2007	**18,857**	**14,823**	**15,227**	**17,335**	**87.8**	**9,094**	**1,393**	**4,241**	**689**
Apr. 27, 2007*	**18,780**	**14,953**	**15,332**	**17,335**	**88.5**	**8,814**	**1,365**	**4,195**	**710**
May 5, 2006	**16,682**	**15,040**	**15,301**	**17,115**	**89.4**	**8,188**	**1,414**	**3,867**	**626**

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

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*5-4-07	*5-5-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	87.07	86.58	0.49	0.6
Brent crude	66.50	72.59	–6.09	–8.4
Crack spread	20.57	10.72	9.86	92.0
FUTURES MARKET PRICES				
One month				
Product value	88.70	86.35	2.35	2.7
Light sweet crude	63.78	72.14	–8.36	–11.6
Crack spread	24.91	14.20	10.71	75.4
Six month				
Product value	80.78	84.59	–3.81	–4.5
Light sweet crude	68.55	75.68	–7.13	–9.4
Crack spread	12.23	8.91	3.32	37.2

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

OGJ GASOLINE PRICES

	Price ex tax 5-2-07	Pump price* 5-2-07	Pump price 5-3-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	252.3	292.0	293.6
Baltimore	255.3	297.2	299.5
Boston	245.4	287.3	292.9
Buffalo	243.2	303.3	302.6
Miami	260.0	310.3	306.9
Newark	243.5	276.4	288.9
New York	235.2	295.3	306.0
Norfolk	247.3	284.9	295.9
Philadelphia	247.3	298.0	305.6
Pittsburgh	237.3	288.0	293.3
Wash., DC	263.4	301.8	311.0
PAD I avg.	248.2	294.0	299.7
Chicago	271.0	321.9	316.9
Cleveland	241.5	287.9	283.1
Des Moines	243.5	283.9	271.6
Detroit	241.8	291.0	285.6
Indianapolis	247.9	292.9	280.2
Kansas City	242.0	278.0	268.5
Louisville	257.9	294.8	285.6
Memphis	243.1	282.9	280.6
Milwaukee	250.5	301.8	294.7
Minn.-St. Paul	242.6	283.0	277.3
Oklahoma City	243.5	278.9	267.9
Omaha	242.6	289.0	284.0
St. Louis	248.9	284.9	272.2
Tulsa	245.5	280.9	269.3
Wichita	239.5	282.9	269.7
PAD II avg.	246.8	289.0	280.5
Albuquerque	253.5	289.9	288.4
Birmingham	245.2	283.9	282.2
Dallas-Fort Worth	250.4	288.8	298.1
Houston	246.5	284.9	292.5
Little Rock	241.7	281.9	278.4
New Orleans	243.5	281.9	284.7
San Antonio	233.5	271.9	276.5
PAD III avg.	244.9	283.3	285.8
Cheyenne	243.2	275.6	259.5
Denver	253.8	294.2	276.6
Salt Lake City	242.5	285.4	274.3
PAD IV avg.	246.5	285.1	270.1
Los Angeles	280.6	339.1	330.6
Phoenix	263.5	300.9	306.0
Portland	273.7	317.0	299.2
San Diego	290.5	349.0	337.1
San Francisco	304.6	363.1	335.8
Seattle	272.5	324.9	315.6
PAD V avg.	280.9	332.4	320.7
Week's avg.	**251.7**	**295.3**	**291.4**
Apr. avg.	**234.7**	**278.3**	**270.5**
Mar. avg.	**210.4**	**254.0**	**235.4**
2007 to date	**204.3**	**247.9**	—
2006 to date	**200.7**	**243.2**	—

*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

	4-27-07 ¢/gal		4-27-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil, No. 2	
New York Harbor	226.85	New York Harbor	191.35
Gulf Coast	228.29	Gulf Coast	187.75
Los Angeles	259.04	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	207.22	ARA	188.57
Singapore	204.64	Singapore	193.57
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	239.10	New York Harbor	122.02
Gulf Coast	231.54	Gulf Coast	126.19
Los Angeles	267.54	Los Angeles	133.80
		ARA	107.23
		Singapore	130.76

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

BAKER HUGHES RIG COUNT

	5-4-07	5-5-06
Alabama	3	5
Alaska	7	7
Arkansas	43	23
California	33	32
Land	32	26
Offshore	1	6
Colorado	107	85
Florida	0	0
Illinois	0	0
Indiana	3	0
Kansas	13	8
Kentucky	8	6
Louisiana	181	194
N. Land	60	59
S. Inland waters	26	20
S. Land	32	38
Offshore	63	77
Maryland	0	0
Michigan	2	1
Mississippi	16	7
Montana	20	22
Nebraska	0	0
New Mexico	74	94
New York	5	5
North Dakota	33	26
Ohio	13	6
Oklahoma	186	177
Pennsylvania	15	14
South Dakota	2	1
Texas	831	743
Offshore	10	13
Inland waters	1	4
Dist. 1	20	24
Dist. 2	31	25
Dist. 3	56	71
Dist. 4	93	79
Dist. 5	169	135
Dist. 6	122	106
Dist. 7B	43	40
Dist. 7C	61	40
Dist. 8	106	78
Dist. 8A	25	28
Dist. 9	39	29
Dist. 10	55	71
Utah	41	42
West Virginia	32	26
Wyoming	70	99
Others—NV-3; TN-3; VA-3	9	2
Total US	**1,747**	**1,625**
Total Canada	**89**	**167**
Grand total	**1,836**	**1,792**
Oil rigs	282	259
Gas rigs	1,462	1,365
Total offshore	74	96
Total cum. avg. YTD	**1,738**	**1,544**

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

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

SMITH RIG COUNT

Proposed depth, ft	5-4-07 Rig count	5-4-07 Percent footage*	5-5-06 Rig count	5-5-06 Percent footage*
0-2,500	57	7.0	55	—
2,501-5,000	109	53.2	94	44.6
5,001-7,500	223	15.6	218	16.9
7,501-10,000	400	2.5	352	1.9
10,001-12,500	439	4.1	371	2.9
12,501-15,000	253	0.7	268	—
15,001-17,500	105	0.9	112	0.8
17,501-20,000	77	—	76	—
20,001-over	35	—	20	—
Total	**1,698**	**7.5**	**1,566**	**6.2**
INLAND	37		44	
LAND	1,596		1,458	
OFFSHORE	65		64	

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

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]5-4-07	[2]5-5-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	769	800
California	658	686
Colorado	50	62
Florida	6	6
Illinois	29	28
Kansas	95	99
Louisiana	1,347	1,218
Michigan	14	16
Mississippi	48	48
Montana	91	96
New Mexico	161	162
North Dakota	105	105
Oklahoma	166	171
Texas	1,310	1,304
Utah	45	50
Wyoming	141	140
All others	60	69
Total	**5,114**	**5,081**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	5-4-07
Alaska-North Slope 27°	50.90
South Louisiana Sweet	65.00
California-Kern River 13°	51.80
Lost Hills 30°	59.65
Wyoming Sweet	57.93
East Texas Sweet	59.12
West Texas Sour 34°	51.65
West Texas Intermediate	58.50
Oklahoma Sweet	58.50
Texas Upper Gulf Coast	55.25
Michigan Sour	51.50
Kansas Common	57.50
North Dakota Sweet	53.00

*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]	4-27-07
United Kingdom-Brent 38°	67.13
Russia-Urals 32°	63.01
Saudi Light 34°	62.65
Dubai Fateh 32°	63.82
Algeria Saharan 44°	70.13
Nigeria-Bonny Light 37°	70.24
Indonesia-Minas 34°	68.80
Venezuela-Tia Juana Light 31°	60.35
Mexico-Isthmus 33°	60.24
OPEC basket	65.18
Total OPEC[2]	64.35
Total non-OPEC[2]	61.94
Total world[2]	63.25
US imports[3]	59.19

[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]

	4-27-07	4-20-07	Change
	Bcf		
Producing region	672	647	25
Consuming region east	716	664	52
Consuming region west	263	253	10
Total US	**1,651**	**1,564**	**87**
	Feb. 07	**Feb. 06**	**Change, %**
Total US[2]	**1,649**	**1,886**	**–12.6**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in OGJ Online Research Center

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Feb. 2007	Jan. 2007	2 month average production 2007	2 month average production 2006	Change vs. previous year Volume	Change vs. previous year %	Feb. 2007	Jan. 2007	Cum. 2007
	Crude, 1,000 b/d						Gas, bcf		
Argentina	631	628	630	613	17	2.8	110.0	122.9	232.86
Bolivia	43	45	44	45	–1	–2.2	39.0	40.0	79.00
Brazil	1,758	1,736	1,747	1,690	57	3.4	26.0	28.0	54.00
Canada	2,620	2,554	2,587	2,540	47	1.8	504.1	532.4	1,036.49
Colombia	515	522	519	527	–9	–1.6	16.0	18.0	34.00
Ecuador	500	515	508	557	–50	–8.9	0.3	0.3	0.59
Mexico	3,148	3,143	3,146	3,342	–196	–5.9	162.7	177.8	340.52
Peru	114	120	117	114	3	2.9	5.4	5.7	11.10
Trinidad	124	121	122	150	–27	–18.3	107.1	113.2	220.31
United States	5,298	5,196	5,247	5,048	200	4.0	1,486.0	1,655.0	3,141.00
Venezuela[1]	2,430	2,490	2,460	2,645	–185	–7.0	70.0	80.0	150.00
Other Latin America	79	80	80	78	2	2.6	6.8	7.5	14.32
Western Hemisphere	**17,261**	**17,150**	**17,205**	**17,347**	**–142**	**–0.8**	**2,533.3**	**2,780.9**	**5,314.20**
Austria	18	17	18	17	—	2.3	4.9	5.4	10.30
Denmark	306	318	312	357	–45	–12.6	29.6	32.4	61.99
France	17	19	18	22	–4	–17.0	3.0	3.3	6.30
Germany	70	70	70	73	–3	–4.0	52.0	58.1	110.06
Italy	114	106	110	115	–5	–4.3	28.0	30.8	58.80
Netherlands	40	40	40	32	9	27.0	350.0	400.0	750.00
Norway	2,454	2,431	2,443	2,639	–196	–7.4	257.8	287.1	544.94
Turkey	40	38	39	40	–1	–2.3	3.1	3.4	6.50
United Kingdom	1,671	1,530	1,600	1,695	–95	–5.6	221.2	257.6	478.80
Other Western Europe	5	4	5	5	—	–0.5	2.9	3.1	5.98
Western Europe	**4,735**	**4,572**	**4,654**	**4,994**	**–340**	**–6.8**	**952.4**	**1,081.3**	**2,033.67**
Azerbaijan	850	850	850	550	300	54.5	20.0	24.0	44.00
Croatia	16	16	16	17	–1	–4.5	5.6	6.5	12.16
Hungary	18	16	17	19	–2	–9.5	7.1	8.0	15.09
Kazakhstan	1,200	1,200	1,200	975	225	23.1	80.0	80.0	160.00
Romania	98	97	98	100	–3	–2.5	16.6	18.4	35.00
Russia	9,750	9,700	9,725	9,300	425	4.6	1,900.0	2,100.0	4,000.00
Other FSU	400	400	400	500	–100	–20.0	400.0	480.0	880.00
Other Eastern Europe	50	48	49	50	–1	–1.9	47.4	50.5	97.94
Eastern Europe and FSU	**12,383**	**12,327**	**12,355**	**11,511**	**844**	**7.3**	**2,476.8**	**2,767.4**	**5,244.19**
Algeria[1]	1,320	1,340	1,330	1,360	–30	–2.2	255.0	285.0	540.00
Angola[1]	1,614	1,584	1,599	1,415	183	13.0	2.3	2.5	4.80
Cameroon	85	84	85	88	–3	–3.7	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	660	660	660	695	–35	–5.0	38.0	42.0	80.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.12
Gabon	230	230	230	240	–10	–4.2	0.3	0.3	0.59
Libya[1]	1,690	1,700	1,695	1,660	35	2.1	19.5	22.0	41.50
Nigeria[1]	2,250	2,280	2,265	2,310	–45	–1.9	70.0	78.0	148.00
Sudan	300	300	300	290	10	3.4	—	—	—
Tunisia	89	92	90	66	25	37.5	6.4	7.2	13.58
Other Africa	262	262	262	249	13	5.3	9.6	10.2	19.71
Africa	**9,079**	**9,112**	**9,096**	**8,953**	**143**	**1.6**	**401.0**	**447.3**	**848.30**
Bahrain	170	170	170	175	–5	–2.9	24.0	27.0	51.00
Iran[1]	3,860	3,900	3,880	3,810	70	1.8	230.0	260.0	490.00
Iraq[1]	1,980	1,700	1,840	1,670	170	10.2	5.0	5.0	10.00
Kuwait[1,2]	2,420	2,460	2,440	2,518	–78	–3.1	28.0	31.0	59.00
Oman	720	730	725	755	–30	–4.0	52.0	58.0	110.00
Qatar1	800	810	805	820	–15	–1.8	100.0	115.0	215.00
Saudi Arabia[1,2]	8,460	8,560	8,510	9,308	–798	–8.6	140.0	160.0	300.00
Syria	390	400	395	440	–45	–10.2	14.4	16.0	30.40
United Arab Emirates[1]	2,540	2,600	2,570	2,585	–15	–0.6	120.0	135.0	255.00
Yemen	350	360	355	345	10	2.9	—	—	—
Other Middle East	—	—	—	—	—	–12.6	7.7	9.1	16.78
Middle East	**21,690**	**21,690**	**21,690**	**22,425**	**–735**	**–3.3**	**721.1**	**816.1**	**1,537.18**
Australia	485	425	455	348	107	30.9	100.0	110.0	210.00
Brunei	191	186	188	198	–9	–4.7	31.8	34.6	66.35
China	3,749	3,822	3,786	3,681	104	2.8	204.7	206.5	411.17
India	700	688	694	661	33	5.0	72.3	81.4	153.68
Indonesia[1]	840	860	850	920	–70	–7.6	165.0	185.0	350.00
Japan	15	19	17	19	–2	–9.0	10.0	12.3	22.29
Malaysia	780	780	780	770	10	1.3	125.0	140.0	265.00
New Zealand	15	15	15	16	–1	–3.2	9.5	10.5	20.00
Pakistan	65	65	65	65	—	–0.3	108.0	120.0	228.00
Papua New Guinea	55	55	55	58	–3	–5.2	0.5	0.5	0.95
Thailand	205	195	200	217	–17	–7.7	68.0	73.5	141.47
Vietnam	340	330	335	350	–15	–4.3	13.5	15.0	28.50
Other Asia-Pacific	38	38	38	31	7	21.6	56.3	62.5	118.80
Asia-Pacific	**7,478**	**7,477**	**7,478**	**7,333**	**145**	**2.0**	**964.5**	**1,051.7**	**2,016.21**
TOTAL WORLD	**72,626**	**72,329**	**72,477**	**72,562**	**–85**	**–0.1**	**8,049.2**	**8,944.6**	**16,993.75**
*OPEC	30,204	30,284	30,244	29,605	639	2.2	1,202.5	1,356.0	2,558.50
North Sea	4,445	4,295	4,370	4,707	–337	–7.2	613.4	697.0	1,310.42

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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Survey confirms US confusion about energy

Surveys can provide important ratification of the obvious. One recent survey, for example, indicates Americans know little about energy.

Conducted by the Manhattan Institute's Center for Energy Policy and the Environment (CEPE) and Zogby International, the survey quizzed 1,000 Americans on basic energy facts.

"The survey found that the views that

The Editor's Perspective

by Bob Tippee, Editor

Americans hold about a wide range of these issues are, in key ways, inaccurate," wrote Max Schulz, CEPE senior fellow, in a report summary.

According to Schulz, a former policy advisor and speech writer for US energy secretaries, "significant numbers of people" don't understand matters such as:

- ***Fuels representing the main sources of energy.*** *More than 60% of respondents think most US energy comes from oil, which represents 40% of supply.*
- ***Main uses of energy supplies.*** *Almost half think incorrectly that transportation accounts for most US energy consumption.*
- ***Countries that supply the most oil to the US.*** *More than half think Saudi Arabia is the No. 1 supplier. It's really No. 3, in a tie with Venezuela behind Canada and Mexico.*
- ***Extent of oil reserves.*** *Forty-three percent think the world will run out of oil during this century.*
- ***The rate of global warming.*** *More than three fourths believe warming was greater in the second half of the past century than during the first, apparently unaware of the decline in global average temperature during 1945-75.*
- ***Terms of the Kyoto Protocol on climate change.*** *Sixty percent mistakenly believe the agreement requires all countries to cut emissions of greenhouse gas.*
- ***The environmental record of nuclear power plants.*** *Only 17% know that no one died in the 1979 partial meltdown at the Three Mile Island plant in Pennsylvania.*
- ***The extent of urban air pollution.*** *Eighty-four percent incorrectly believe urban pollution is rising.*
- ***Effects of conservation and increases in energy efficiency.*** *Two thirds or more believe the US can meet future energy needs solely with conservation and efficiency measures.*

The misunderstanding on display here helps explain US bamboozles such as the ethanol mandate, which is among several other subjects covered in the report. It's at www.manhattaninstitute.org.

(Online May 4, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Gas tests $8/MMbtu

The June natural gas contract briefly pushed past $8/MMbtu May 3-4 in a rally by hedge-fund investors that forced traders to cover short positions on the New York market. The contract touched $8/MMbtu before it closed at $7.95/MMbtu May 3, up 21.7¢ for the day on the New York Mercantile Exchange. It climbed as high as $8.11/MMbtu May 4, before settling at $7.94/MMbtu. On the US spot market, however, gas at Henry Hub, La., lost 7¢ to $7.55/MMbtu May 3 and remained unchanged May 4.

"Futures prices through October were up 20¢ or more as hedge funds went on a calculated buying spree, forcing traders out of short positions ahead of rapidly increasing prices, which perpetuated the rally," said analysts at Enerfax Daily.

Robert S. Morris, Banc of America Securities LLC, New York, noted a 6.5% rise in composite spot gas prices over the five trading sessions that week. "Natural gas prices began the week with a strong rally as near-record warm temperatures permeated much of the country while technical factors boosted the near-month NYMEX futures contract to over $8/MMbtu," he said.

"Also, despite a higher-than-expected natural gas storage injection figure that week, and with the traditionally weak seasonal shoulder period upon us, natural gas futures prices also seem to be looking ahead with the official start of both the Atlantic Basin hurricane season and summer less than a month away," Morris said. "Most prognosticators are calling for a more-active-than-normal hurricane season and a warmer-than-normal summer."

Enerfax analysts said, "By all accounts the nation is flush with natural gas, and inventories are expected to build quickly over the next several weeks." Above-average temperatures were expected to stretch across the entire middle of the US and fan out to cover most of the US through mid-May.

Crude prices

Crude futures prices fell 7% Apr. 30-May 4 in the largest weekly decline since Jan. 5 in the New York market. "Oil prices started the week on a downward trend after supply fears that had stoked the market at the end of the prior week—when Saudi Arabia arrested 172 militants and thwarted a terrorist plot targeting its oil fields and oil infrastructure—eased," Morris said. Otherwise, he said, the US crude and product inventory report through Apr. 27 was largely in line with expectations while the Department of Energy suspended refilling the US Strategic Petroleum Reserve until at least the end of the summer driving season because recent bids were "too high and not a reasonable value for taxpayers."

US crude inventory levels were 5% above the 5-year average on Apr. 27, said Raymond James analysts. However, they said, "Going forward, significantly below-average gasoline inventories and above-average demand for gasoline should continue to give support to crude prices, while many investors are beginning to look toward other commodity markets." US gasoline inventories declined for 12 straight weeks through Apr. 27, and, as refiners come back online and increase refinery utilization, this will increase the US's crude demand, said Raymond James.

Meanwhile, Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, noted, "The main fundamental [crude market] change this year vs. 2005 or most of 2006 has been the re-creation of the Organization of Petroleum Exporting Countries' spare capacity through quota reduction." He said, "When OPEC production was operating at full capacity, producers had little incentive to hedge; whereas nowadays the incentive is to hedge more of the production on flat price increases in order to front-run any potential OPEC cheating. The resurgence of producer hedging will play a greater flat-price capping role than in the 2 previous years and was probably a factor in the failure of crude to break the resistance lines in the higher $60/bbl level.

"Gasoline demand is up 97,000 b/d, but production is up 241,000 b/d. Hence the US fundamentals situation stays unchanged," Jakob said. Despite production cuts this year by the Organization of Petroleum Exporting Countries, he said, "US refineries have so far faced no problems [finding] the required crude imports, while gasoline is not able yet to end its flirt with minimum of inventory levels."

Jakob also noted the reduction of the US Navy's armada in Middle East waters, with one aircraft carrier, the USS Eisenhower, sailing back through the Red Sea; another carrier, the USS Nimitz, currently in the Philippine Sea, leaving only the USS Stennis to cover Afghanistan. That, he said, "coincides with the goodwill attitude that has been shown before the start of the Iraq conference and is leading to a lowering of the Iranian premium [on world oil prices]."

(Online May 7, 2007; author's e-mail: samf@ogjonline.com)

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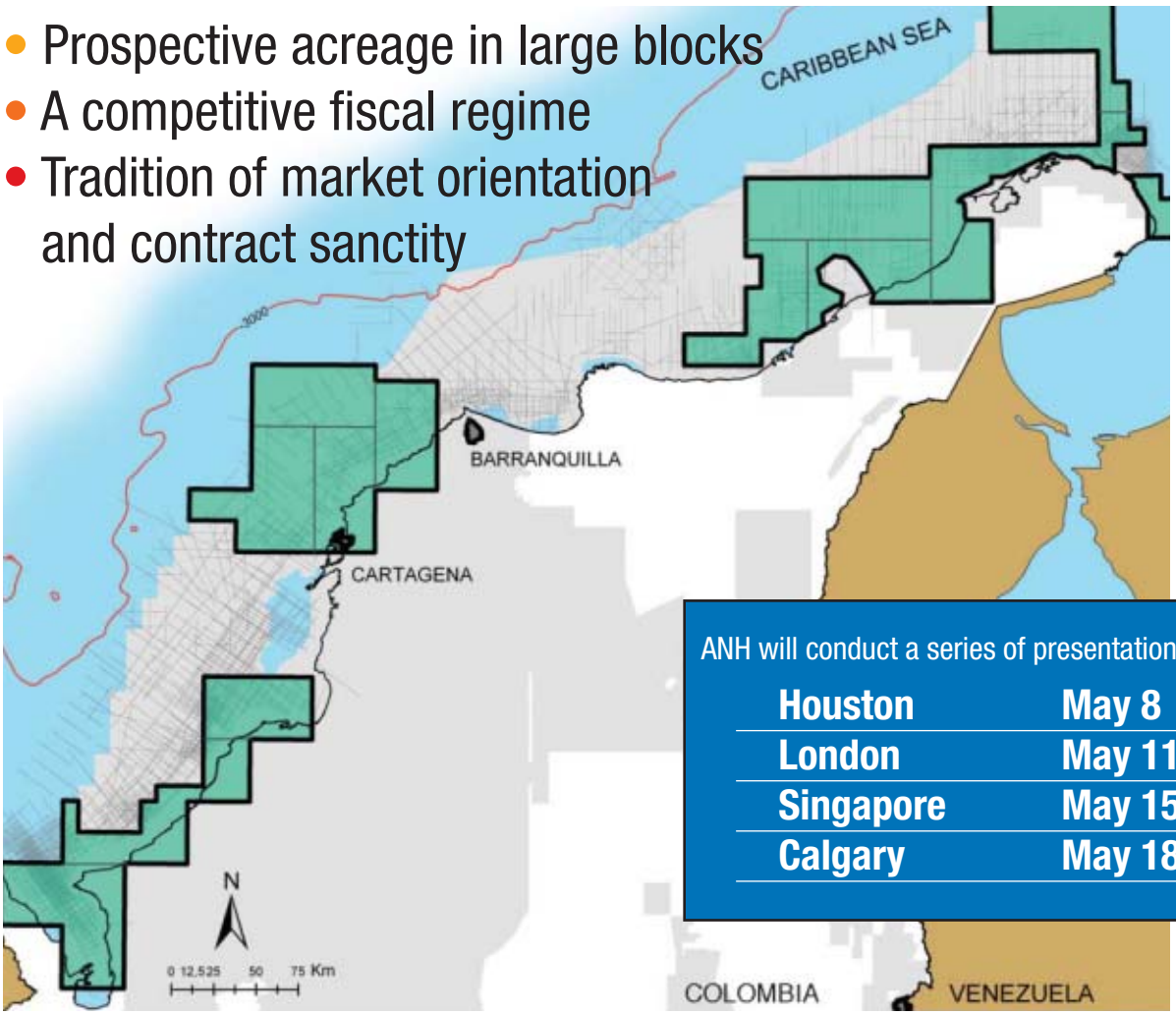

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