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Worldwide Pipeline Construction

RUSSIA'S POWER DRIVE—2: *Controlling gas to Europe, Asia*
Central Wilmington oil field due for denser development
Approach diagnoses, reduces water cut
Biodiesel tax credits present incentives if handled properly

OIL&GAS JOURNAL®

Feb. 19, 2007
Volume 105.7

WORLDWIDE PIPELINE CONSTRUCTION

REGULAR FEATURES

COVER

Welders make a tie-in weld on the 30-in. portion of 40 miles of 30-in. and 42-in. Energy Transfer Partners mainline between Bethel compressor station, Anderson County, Tex., and Reed compressor station, Freestone County, Tex. The project is part of a multiphase expansion intended to provide producers in the Bossier Sand and Barnett shale basins in East and North Texas an outlet to various markets throughout Texas, as well as to the national marketplace through downstream interstate pipelines. Such expansions, fueled by continued growth in natural gas demand, have led to continued growth in proposed pipeline construction projects, both in North America and around the world. Oil & Gas Journal's special report on Worldwide Pipeline Construction, which begins on p. 48, provides more information on construction trends and plans for both 2007 and beyond. Photograph from Willbros USA Inc. by Lindy King.

Network Convergence Gives Energy Sector Companies an Edge

By Chuck Pol, President, BT Americas and Ross Burley, Director of Oil & Gas Sales, BT Americas

Global demand for Oil & Gas continues to grow unabated, and the industry's major preoccupation is with replacing reserves and shortening the development cycle. But pressure to increase efficiency and reduce costs throughout the energy industry is also on the rise. Companies are constantly looking for ways to improve productivity and efficiency. Taking advantage of changes in communications can help your business do both.

Changes in technology are simplifying and unifying communications today. Where once a company needed separate data, voice and video networks, all can now be carried seamlessly over a single, converged network running on Internet Protocol (IP) standards. This means increased efficiency, simplicity, and cost savings.

What does this mean to the energy industry? Many companies in this sector manage multiple networks – legacy systems inherited through mergers or acquisitions, country-specific networks, or networks based on single technologies, such as satellite communications to reach remote areas. The interoperability challenges, complexity, cost and sometimes unstable performance of these networks argues in favor of implementing a single, global, converged network, under a single global service level agreement.

Beyond cost cutting

But cost savings and efficiency aren't the only benefits of network convergence. Today's networks give companies whole new ways of operating – ways to improve collaboration, use expertise more efficiently, collect and use data to improve operations and gain competitive advantage.

For example, BT's Digital Networked Oilfield solution provides companies in the exploration and production industry with real-time access to production and exploration data in a secure, end-to-end managed environment that improves and speeds decision-making. By enabling greater collaboration, this solution reduces costs, cuts downtime and increases production. And it's based on BT's global IP network, configured to optimize application performance and extended through satellite, which means it can be deployed almost anywhere. And it's customizable to a company's exact needs.

Why BT?

BT's network capability is world class, and is being enhanced with a $20 billion investment program to build the "21st Century Network." But when operating globally, implementing new operational models or supporting new business models, it's about more than just the network – it's about experience, expertise and partnership.

You can rely on BT. We know how to build a global network infrastructure, we know how to design global business models, we know how to handle contractual, regulatory and tax details around the world. In short, BT helps customers operate globally. And we're ready to help you.

To learn more about how BT can help you gain a competitive advantage visit www.bt.com/networked or contact Ross Burley, Director of Oil & Gas Sales, at 713.499.3410 or ross.burley@bt.com.

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General Interest — Quick Takes

GOM 'top deepwater hunting grounds' in 2006

Exploration in the deepwater Gulf of Mexico marked an exceptionally successful year during 2006, consultancy Wood Mackenzie Ltd. said in a recent report entitled "Treasures of the Deep: A Review of 2006 Exploration."

Zoe Sutherland, WoodMac gulf analyst, called the gulf "one of the top deepwater hunting grounds in the world." She told OGJ in a telephone interview from her Edinburgh office that she believes 2007 will hold similar potential to the 2006 discoveries. "The rate of exploration activity will stay the same."

Sutherland said WoodMac's own early reserves estimates for 2006 discoveries suggest 1.5 billion boe proved and probable reserves in the region. The actual reserves numbers, yet to be booked by the companies, could prove to be smaller, WoodMac noted.

Over the last 10 years, oil and gas reserves found in the deepwater gulf averaged 1.2 billion boe/year. Both 2004 and 2005 marked deepwater reserves additions of less than 1 billion boe.

During 2006, highlights included discoveries by BP PLC at Kaskida and Hess Corp. at Pony. Together these two fields account for more than half of the reserves found in the region last year.

BP E&P Inc. discovered oil with the Kaskida well on Keathley Canyon Block 292. Kaskida encountered 800 net ft of hydrocarbon pay in Lower Tertiary sands. Interests are BP 55%, Anadarko Petroleum Corp. 25%, and Devon Energy Corp. 20% (OGJ Online, Aug. 31, 2006).

Hess said wireline logs of its deepwater Pony prospect on Green Canyon Block 468 indicate 475 ft of oil-saturated sandstones in Miocene age reservoirs. Hess drilled the well to 32,448 ft TD (OGJ, July 24, 2006, Newsletter).

WoodMac noted the number of wells drilled in 2006 increased marginally compared with 2005, while the number of drilling days increased by nearly 30%. Deeper, more complex deepwater exploration led to an average drill time of more than 100 days.

Undoubtedly spurred by successful Lower Tertiary wells in remote areas of the gulf, operators extended their search for the play into waters closer to shore, WoodMac said. BP drilled its Tamara prospect in Garden Banks, north of Keathley Canyon, and Hess spudded a well at Jack Hays in Port Isabel, the most westerly test of the play so far.

Trial begins for 1999 Erika oil spill

Seven years after the Erika oil tanker spill off Brittany's Penmarc'h point, which polluted 400 km of France's Brittany coastline, 15 accused are facing a trial that began Feb. 12 and is due to last until June 13. It is expected to cost €600,000 (OGJ, Feb. 13, 2006, Newsletter).

There are 70 parties involved in the case ranging from local Brittany administrations and associations to Italian and Greek ship owners and environmental activists and associations clamoring for more-drastic maritime security and transparency.

Total SA is the focus of the trial because the company chartered the vessel, which was carrying 30,884 tonnes of heavy fuel oil and broke in two during a storm, releasing 20,000 tonnes of fuel. Total was indicted Nov. 7, 2001.

Total already has spent €200 million to pump out the fuel in the wreck, to treat 220,000 tonnes of polluted sand, and to clean up the coast.

Victims of the spill have obtained €118 million from the Oil Pollution Compensation Fund and should receive an additional €40 million when all claims have been dealt with. But damages claimed amount to practically €1 billion.

The trial also will bring to light the complexities and shortcomings of maritime transport embroiled in the mix of insurers, ship owners and charterers, convenience flags, negligent certification companies, and poor managers.

Although certified seaworthy, the 25-year-old tanker had changed its name and owner eight times, its classification company four times, and its flag three times, and had been poorly patched and maintained. The Erika, together with the Prestige off Spain 2 years later, was instrumental in inducing the European Union to establish stricter rules for tanker age and construction.

It is hoped that the trial will work out the responsibilities of each accused at every stage of the Erika saga.

Ecuador threatens environmental squeeze

Ecuador President Rafael Correa, who was sworn in last January and is a close ally of Venezuelan President Hugo Chavez, said he might cancel contracts of foreign oil companies that harm the environment.

Analysts see that as a threat to a Petroleo Brasileiro SA (Petrobras) block in one of the largest ecological reserves in the world, Park Yasuni.

Petrobras in 2004 won a license to explore Block 31, part of which is in a reserve considered one of the world's most biologically diverse areas and home to primitive tribes.

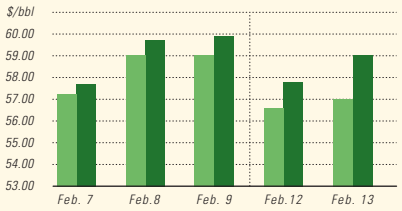
Petrobras officials were not immediately available for comment, but the company has said it is using modern technology to avoid damaging the park.

The Brazilian company has insisted that the project, in which Teikoku is a partner, will affect only 100 hectares of the Yasuni reserve, which borders Peru.

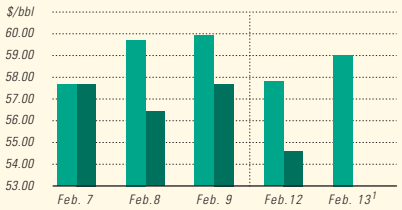
The Ecuadorian economy got a $1.1 billion boost from the confiscation of Occidental Petroleum Corp.'s Block 15 in May 2006 and a new hydrocarbon tax, which together bumped up the country's total 2006 oil revenue to about $3.8 billion, say local analysts (OGJ, May 22, 2006, Newsletter).

Industry Scoreboard

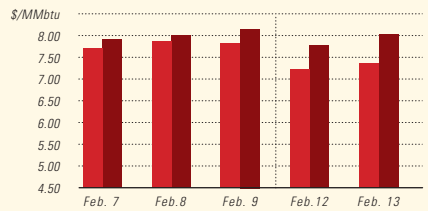
IPE BRENT / NYMEX LIGHT SWEET CRUDE



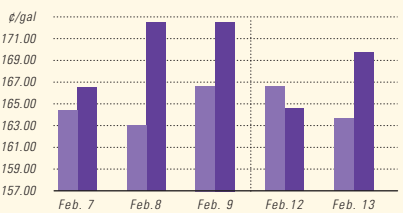
WTI CUSHING / BRENT SPOT



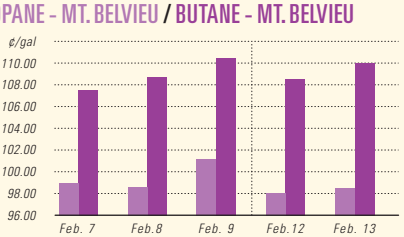
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



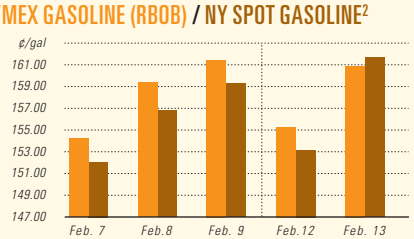
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

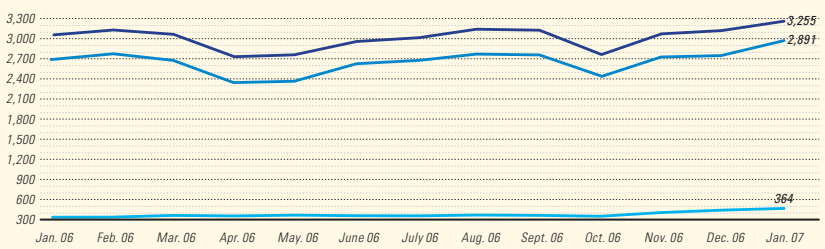
US INDUSTRY SCOREBOARD — 2/19

Latest week 2/9	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	9,113	8,762	4.0	9,028	8,781	2.8
Distillate	4,536	4,211	7.7	4,366	4,240	3.0
Jet fuel	1,629	1,532	6.3	1,633	1,534	6.5
Residual	577	833	–30.7	591	817	–27.7
Other products	4,805	4,838	–0.7	4,842	4,841	—
TOTAL DEMAND	20,660	20,176	2.4	20,460	20,213	1.2
Supply, 1,000 b/d						
Crude production	5,282	5,047	4.6	5,311	5,048	5.2
NGL production	2,369	1,682	40.8	2,401	1,681	42.8
Crude imports	9,175	9,768	–6.1	9,498	9,794	–3.0
Product imports	3,055	3,722	–17.9	3,130	3,654	–14.4
Other supply[2]	957	1,348	–29.0	1,007	1,399	–28.0
TOTAL SUPPLY	20,837	21,566	–3.4	21,346	21,575	–1.1
Refining, 1,000 b/d						
Crude runs to stills	14,552	14,733	–1.2	14,793	14,698	0.6
Input to crude stills	14,953	15,053	–0.7	15,223	15,039	1.2
% utilization	86.3	86.8	—	87.8	86.8	—

Latest week 2/9	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	325,251	328,618	–3,367	328,979	–3,728	–1.1
Motor gasoline	215,430	216,033	–606	219,675	–4,245	–1.9
Distillate	135,118	135,490	–372	137,350	–2,232	–1.6
Jet fuel	41,430	40,530	900	43,503	–2,073	–4.8
Residual	43,943	45,093	–1,150	40,122	3,821	9.5
Stock cover (days)[3] **2/2**			**Change, %**		**Change, %**	
Crude	21.8	21.5	1.4	21.9	–0.5	
Motor gasoline	25.0	24.7	1.2	25.1	–0.4	
Distillate	31.6	33.7	–6.2	32.4	–2.5	
Propane	25.6	31.8	–19.5	31.7	–19.2	
Futures prices[4] **2/9**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	59.05	57.86	1.19	63.04	–3.99	–6.3
Natural gas, $/MMbtu	7.73	7.47	0.26	7.68	0.05	0.7

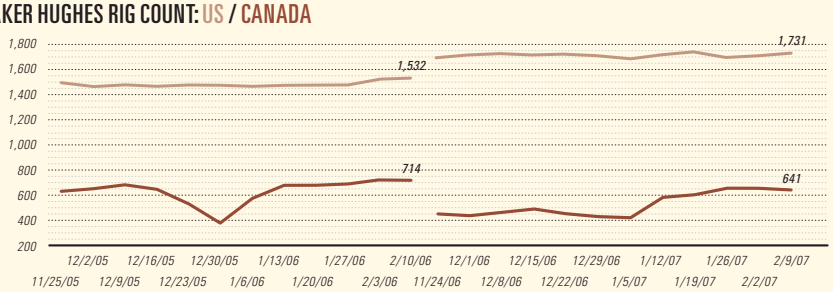
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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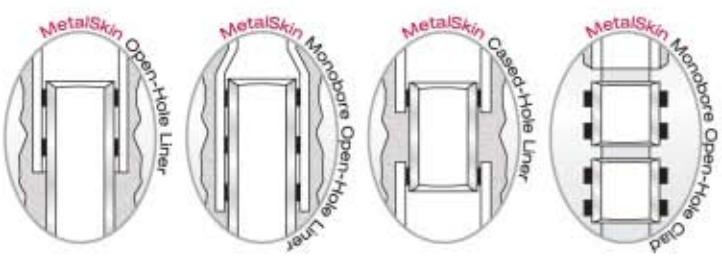

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The government's threat fits a pattern that some observers fear will spread following the Russian government's success in taking majority control of the Sakhalin-2 project after challenging the project on environmental grounds (OGJ, Jan. 15, 2007, p. 34). ✦

Exploration & Development — *Quick Takes*

Total makes two oil finds on Angola's Block 32

Total SA reported making two oil discoveries on deepwater Block 32 off Angola.

The Manjericão-1 well tested more than 5,000 b/d of oil from Oligocene oil-bearing reservoirs. This discovery is 38 km northwest of the Gengibre-1 discovery made in 2004. Total said the discovery shows "there is additional resource potential in the previously unexplored central area" of the block. The well was drilled in 1,977 m of water in the central part of Block 32.

The second well, Caril-1, produced 6,300 b/d of light oil from a selected interval in Oligocene oil-bearing reservoirs. It was drilled in 1,673 m of water in the northeastern part of Block 32, about 18 km north-northwest of the Gindungo-1, and 7 km west-southwest of Cola-1, discoveries that were made in 2003 and 2004, respectively.

Total said technical studies are being carried out to fully evaluate these drilling results, and further exploration drilling is under way across the block.

Total holds a 30% interest in Block 32 and serves as operator. Other partners in Block 32 are Marathon Oil Co. 30%, Sonangol EP 20%, Esso E&P Angola (Overseas) Ltd. 15%, and Petrogal 5%.

Appraisal well extends Syrah field in Egypt

Apache Corp., Houston, said its Syrah 5X appraisal well in Egypt's Western Desert tested 47.6 MMcfd of gas from the Jurassic Lower Safa sand, extending Syrah field to the northwest.

The Syrah 5X well targeted the lower 50 ft of Lower Safa pay. The well flowed from perforations at 14,210-60 ft through a 1-in. choke with 2,599 psi flowing wellhead pressure.

Syrah field, which lies on the Khalda Concession, is slated to begin production in third quarter 2008, following completion of continuing infrastructure expansion in the greater Khalda area.

The field lies 4 miles north of Qasr field, Apache's largest discovery, which is currently producing 340 MMcfd of gas and 15,800 b/d of condensate from the Lower Safa sand.

Qasr was discovered in 2003 and contains proved reserves of 2.1 tcf of gas and 64.5 million bbl of condensate. This field also is producing 11,800 b/d of oil from the Cretaceous Alem el Bueib (AEB), a shallower formation overlying the deeper Lower Safa.

In March 2005, the Syrah 1X discovery well tested 46.5 MMcfd from a correlative zone. The success of Syrah field, along with newly acquired 3D seismic data, create the potential for further exploration on Apache's acreage to the north in the Matruh Concession, where five Jurassic-AEB exploratory tests are planned this year.

Apache said it is evaluating the Jurassic-AEB potential in the 4 miles between Syrah and Qasr fields.

Apache operates Khalda with a 100% contractor interest.

Colombia gets two-zone Upper Magdalena find

The Hocol subsidiary of Maurel & Prom, Paris, reported a two-zone oil discovery at its La Canada Norte-1 ST well on the San Jacinto/Rio Paez Permit in Colombia's Upper Magdalena basin.

The well, 250 km southwest of Bogota, stopped at TD 1,006 m after encountering six zones that contained oil in the Cretaceous Monserrate and Caballos formations. Combined output of the three Caballos intervals was 700 b/d of 33-34° gravity oil. Monserrate flowed 200 b/d of 17-18° gravity oil after frac.

The LCN-1 well, near La Hocha (Monserrate) oil field 100 km southwest of Neiva, identified proved and probable reserves of 41 million bbl, Maurel & Prom said.

Permit holders are Hocol, operator with 36.67% interest, Cepsa of Spain 33.33%, and Petrobras 30%.

Maurel & Prom produced 5.2 million b/d in Colombia in 2006. It acquired the Hocol assets from Knightsbridge Petroleum in mid-2005 (OGJ Online, Nov. 4, 2004).

La Hocha field, discovered in 2001, went on production in January 2003 and is still being developed.

Lukoil makes find on Condor block in Colombia

OAO Lukoil affiliate Lukoil Overseas Colombia Ltd. made an oil discovery at the Medina structure on the Condor exploration block in Colombia. The block covers 3,089 sq km in the western Llanos oil basin and is one of Colombia's largest exploration blocks.

The find marks Lukoil's first hydrocarbon discovery in the Western Hemisphere, the company said. There was no report from the company regarding flow rates or the oil's properties.

Lukoil Overseas operates the project with 70% interest, while Colombia's Ecopetrol National Oil Co. holds 30%.

Anadarko chases Garden Banks subsalt Miocene

Having drilled three noncommercial ultradeep wildcats in the eastern Garden Banks area of the Gulf of Mexico, Anadarko Petroleum Corp. said it will continue to pursue its Trade Winds play.

The company said it remains encouraged with the geological concepts the wells were designed to test and that the area is still underexplored for subsalt Miocene-age objectives.

Anadarko drilled to measured total depth of 32,500 ft at the Grand Cayman prospect on Garden Banks Block 561, the program's first prospect. The company plugged the well, two blocks east of Oregano oil field. Anadarko had 35% working interest. Participants were Plains Exploration & Production Co. 30%, Statoil ASA 25%, and Newfield Exploration Co. 10%.

The Andros Deep well on Block 342 north of Llano oil field went to MTD 31,800 ft and was plugged. Anadarko and Hess Corp. each held 50%.

The Norman well on Block 434 east-southeast of Llano field went to MTD 27,700 ft and was plugged. Anadarko operated with 41.25% interest. Participating were Norsk Hydro AS with 22.5%,

Plains E&P 15%, Hess 16.25%, and Callon Petroleum Co. 5%.

Anadarko said it is incorporating data from the wells into its seismic modeling and is using the latest seismic imaging technology to identify potential targets below and next to complex salt bodies.

Key farms in to Nyuni East Songo Songo license

Aminex PLC has farmed out a 20% interest in its Nyuni East Songo Songo license off Tanzania to Key Petroleum Ltd.

In exchange Key will fund 30% of the costs for the two exploration wells on Nyuni, one will be spudded in the second quarter and the other will be drilled later in the year. Key also will contribute 10% of all license costs, which are estimated at $2.5 million and have been backdated to Nov. 1, 2006.

If the combined cost of the two proposed wells at Nyuni should exceed $15.4 million, then Key will only be obliged to pay 20% of the excess cost over this amount, the company said.

Aminex and its partners have shot extensive new seismic surveys over shallow reefs and islands and are close to finalizing the location for the first Nyuni well in the current program.

Partners in Nyuni are Aminex 84%, Bounty Oil 6%, and East Africa Exploration Ltd. 10%. Discussions are continuing with Pan-African Tanzania Ltd., a subsidiary of East Coast Energy Ltd., to participate in Nyuni. ✦

Drilling & Production — *Quick Takes*

Statoil starts Gullfaks fields oil production

Statoil ASA has begun oil production from its Skinfaks field and has implemented improved recovery techniques to boost oil output from Rimfaks field. Both lie in the Gullfaks license in the Tampen area of the Norwegian North Sea.

The fields are expected to make up 12% of Gullfaks license production when all wells go on production this fall. Gullfaks produced 130,000 b/d during third quarter 2006.

A Statoil spokesman told OGJ that four of the horizontal wells were completed using the downhole instrumentation and control system (DIACS) to enhance oil recovery at Rimfaks. Rimfaks production before the IOR project was about 17,000 b/d of oil and condensate, he said. DIACS increases oil production from existing wells by monitoring downhole physical properties and correcting them remotely if the conditions are unfavorable.

Rimfaks production was improved by tying back several wells to the Gullfaks C platform. The field was developed in June 2000 as a satellite, with the wellstream tied back to the Gullfaks A platform.

Skinfaks, which was proved in 2002, comprises several smaller structures from the Brent group geological formation. It was developed with a subsea production system tied in to existing christmas trees on Gullfaks South satellite field. Both projects cost $535.8 million to develop, and recoverable reserves are estimated at 62 million boe for Skinfaks and the IOR part of Rimfaks. The recovery ratio for Rimfaks will increase by 36-47% with Skinfaks-Rimfaks IOR.

ADGAS taps Technip for turnkey job

Abu Dhabi Gas Liquefaction Ltd. has awarded a $610 million lump sum turnkey contract to Technip, Paris, to engineer and install gas compressor stations and associated facilities at Das Island in the UAE. Technip's operations and engineering center in Abu Dhabi will execute the contract. Completion is scheduled for fourth quarter 2009.

The plant's facilities, which include compressor and booster stations and fuel gas treatment and gas dehydration units, will treat 211 MMscfd of associated gas produced by fields off Abu Dhabi.

Technip said the project would be configured predominately in large-scale process system modules and interconnecting racks that will be manufactured and assembled at construction yards before being transported and erected at Das Island.

Norne FPSO to be upgraded for Alve gas project

Aker Kvaerner will modify the topsides of the Norne floating production, storage, and offloading unit under a $62.3 million contract so that additional fields can be tied back to Statoil's Alve gas-condensate field in the Norwegian Sea (OGJ, Jan. 22, 2007, Newsletter).

Design and procurement work has started, subject to a letter of intent received Jan. 5, and prefabrication of steel and piping will start in August. The engineering, procurement, construction, and installation contract will be completed in March 2009.

Alve gas field will be phased in with existing infrastructure on the Statoil-operated Norne field. Alve will produce 4 million cu m/day of gas when it begins production in December 2008.

During the first quarter, Statoil plans to award Alve contracts for subsea production equipment, flexible risers, cables for pipeline heating, marine installations, and pipeline laying. "All contracts are pending Norwegian Ministry of Petroleum and Energy approval of the Alve plan for development and operation," Statoil said.

Alve field was proved in 1990 and is a smaller-scale gas and condensate find in production license 159B, around 15 km southwest of Norne field. The find comprises the Garn, Not, Ile, and Tilje formations. Proved gas reserves of 6.8 billion cu m and 8.3 million bbl of condensate lie in the Garn and Not formations. ✦

Processing — *Quick Takes*

Petrovietnam gets funding for Dung Quat refinery

The Vietnam Development Bank has awarded a credit of $1 billion to Vietnam's state-owned Petrovietnam to finance construction of the country's first oil refinery at Dung Quat.

Petrovietnam General Director Tran Ngoc Canh said the loan would be used mainly to pay the consortium carrying out the refinery's engineering, procurement, and construction (EPC) work. In 2005, Petrovietnam reported that major work contracts were in place for constructing the 140,000 b/d refinery (OGJ Online, Aug 25, 2005).

It was reported that Technip engineering centers in Paris and Kuala Lumpur would carry out the EPC contract, while Japan's JGC and Spain's Tecnicas Reunidas would build the crude oil and product tanks, oil pipelines, and an offshore oil delivery system. The Dung Quat refinery, scheduled for completion in 2009, is under construction in the Binh Son District of the central province of Quang Ngai.

On completion, it will process 6.5 million tonnes/year of crude oil to meet about one third of the country's requirements for gasoline, diesel fuel, fuel oil, liquefied petroleum gas, and kerosine.

China approves second Ningbo refinery complex

China has agreed in principal to the construction of a $10 billion refinery and ethylene complex in the port city of Ningbo by a joint venture of Formosa Plastics Group, Taipei, and China Petroleum & Chemical Corp.

Described as the largest-ever foreign investment project on the Chinese mainland, the proposed facility, subject to approval by China's State Council, will have a capacity of 1.2 million tonnes/year of ethylene and 10 million tonnes/year of oil.

Chinese government officials earlier had blocked the proposed facility, saying it could conflict with another refinery project in nearby Zhenhai (OGJ Online, July 19, 2006). However, the officials approved the Ningbo project after learning it will target sales in Taiwan.

Mitsui, Sipchem plan Jubail petchem plant

Mitsui & Co. is considering a joint venture with Saudi International Petrochemical Co. (Sipchem) to construct a petrochemicals plant in Jubail, on the east coast of Saudi Arabia.

With an estimated cost of $7-8 billion, the 1-1.3 million tonne/year plant would use natural gas produced by Saudi Aramco to manufacture ethylene and basic materials for plastics in 2011.

Reports say the Saudi facility is designed to produce 18 types of petrochemicals, including commodity plastics polyethylene and polypropylene and methyl methacrylate.

Sipchem also is said to have called on several other corporations, including DuPont and Lucite International Ltd., to participate in the project, and negotiations are now in the final stages.

The entire project will likely be split into several parts, with Mitsui assisting in the production of PE and PP. Reports say the Japanese firm is expected to sign a general agreement as early as this month.

KBR technology chosen for China propylene plant

Kellogg Brown & Root has been awarded a basic design engineering package for a 200,000 tonne/year nominal capacity propylene plant, to be built at an existing industrial site in Jilin City, China. Jilin Chemical (JiHua) Group Corp., a subsidiary of China National Petroleum Corp., will own and operate the production facility, for which detailed engineering has been awarded to China Petroleum Engineering Co., Northeast Branch Co.

The plant will use KBR's Sperflex technology, a fluidized catalytic cracking process that converts low-value refinery and ethylene plant streams with a high degree of selectivity to propylene, ethylene, and high-octane gasoline.

The unit will be the second of its kind in the world and the first commercial Superflex unit in the Asia-Pacific region, KBR said. The first commercial unit is currently in the start-up phase for Sasol Ltd. in South Africa. ✦

Transportation — *Quick Takes*

ESPO phase 2 on track to complete in 2012

Russia may be able to complete construction of the second phase of the Eastern Siberia-Pacific Ocean (ESPO) pipeline to coincide with plans of the Asia-Pacific Economic Cooperation organization for a summit to be held in Vladivostok in 2012.

Russian oil pipeline operator OAO Transneft is building the 4,000-km ESPO line with the aim of exporting Russian crude to countries in the Asia-Pacific region.

"We may be able to meet the APEC forum with the ESPO fully completed," said Russia's Industry and Energy Minister Victor Khristenko, who praised the speed at which the project is being implemented.

"The first phase of the ESPO [project] will be completed before the end of 2008," said Khristenko, saying the pipeline will reach Skovorodino by then and that there will be an export terminal on the Pacific coast at Kazmino. If necessary, he said, a rail line could be constructed to transport the crude to Kazmino from Skovorodino while the second phase of pipeline construction takes place.

In the first phase, the pipeline system will have capacity to carry 30 million tonnes/year of oil from Taishet to Skovorodino, with the proposed rail system to link Skovorodino with the port terminal at Kozmino.

Khristenko said progress made by Rosneft and Surgutneftegas in constructing the line warrants optimism and that there is no doubt that the first section of the pipe will be filled.

Trinidad and Tobago studying fifth LNG train

Trinidad and Tobago reported it is to begin a prefeasibility study into the construction of a fifth LNG train at its liquefaction plant at Point Fortin, Trinidad.

The Caribbean island's Minister of Energy Lenny Saith told the South Trinidad Petroleum Conference that the study would be concluded by yearend.

"We have already signaled our intention to consider another LNG train. Train X," Saith said. "Now that we have satisfied the domestic demand, we are about to undertake the first concrete steps towards the realization of that objective with a prefeasibility study which we expect to conclude by December 2007."

Trinidad and Tobago has four LNG trains and is the largest exporter of LNG to the US, accounting for almost 70% of US imports.

Saith said if the plant is constructed, the government would be taking a larger share in it and had agreed to work with its partners, BP PLC, BG Group, and Repsol YPF SA towards getting equity in regasification facilities in the US as well as shipping and marketing. ✦

Calendar

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

OIL&GAS JOURNAL online research center

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

2007

FEBRUARY

Pakistan Oil & Gas Conference, Islamabad, (92-21) 6634795, (92-21) 6634795 (fax), website: www.pakoil-gas.com http://www.pakoil-gas.com/ 18-20.

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

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

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

International Conference and Exhibition on Geo-Resources in the Middle East and North Africa, Cairo, 00202 3446411, 00202 3448573 (fax), e-mail: alisadek@mailer.eun.eg, website: www.grmena.com.eg. 24-28.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 25-28.

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

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

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

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

MARCH

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

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

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

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

APRIL

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

OIL&GAS JOURNAL

Gas Storage & US LNG Imports: What's In Store?

The future of many North American LNG terminals may well depend on their access to underground natural gas storage.

LNG WEBCAST HIGHLIGHTS

On February 22, 2007, LNG Observer's Editor, Warren True, will lead a panel discussion on the importance and future of gas storage.

Hal Miller, of the widely respected consultancy Galway Group, will provide an overview of the current state of underground natural gas storage.

Ned Crady, with leading LNG law firm King & Spalding, will cover regulatory and legal issues that may affect development of storage.

Mark Cook, current Chairman of National Energy Services Association (NESA), will discuss how development of a specific storage project fits with planned LNG terminal projects along the US Gulf Coast.

The Panel of Industry Experts Includes:

H.J. "Hal" Miller
Mr. Miller is the Managing Director of Galway Group. His expertise spans technical, strategic planning, and financial areas in the energy industry. Galway's expertise in worldwide LNG matters is widely recognized in the industry.

George E. "Ned" Crady
Mr. Crady is a partner in the Houston office of King & Spalding and is a member of the firm's Global Transactions Practice Group and Latin America Practice Group. He has extensive experience in LNG export projects in Latin America; LNG import projects in the Atlantic Basin; and the negotiation of commodity supply contracts around the world.

Mark D. Cook
Mr. Cook is Principal of SGR Holdings, responsible for selling storage services and overall commercial development for the Southern Pines Energy Center in Greene County, Mississippi. Prior to SGRH, he served as Vice President with Aquila Energy and was instrumental in developing The Exchange Center, providing innovative solutions for natural gas storage and transportation.

February 22, 2007

1:00 pm CST
(2:00 pm EST)

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Journally Speaking

Seeking pipeline security

Christopher E. Smith
Pipeline Editor

The continued expansion of pipeline construction plans detailed in this issue's special report, "Worldwide Pipeline Construction," p. 48, brings with it an increased need to keep the resulting networks operating safely and efficiently. Regular maintenance, stringent integrity management, and an increased focus on preventing inadvertent third-party damage help address this need. No less important, however, is protecting the expanding transportation infrastructure from intentional attack.

Toward this end, the US Department of Homeland Security's Transportation Safety Administration is overseeing a number of pipeline security initiatives falling under the umbrella of DHS's National Infrastructure Protection Plan (NIPP).

Web course

Earlier this month, DHS debuted "Introduction to the National Infrastructure Protection Plan (IS-860)," a web-based course developed jointly with the Federal Emergency Management Agency. The course is offered through FEMA's Emergency Management Institute's online learning center and can be taken either for credit or less formally. Those who take the course for credit will take a final examination and receive a certificate from DHS.

The primary goal is to explain the importance of protecting the US's critical infrastructure and key resources (CI-KR). The course includes lessons that:

- Describe how the NIPP provides the unifying structure for integrating CI-KR protection efforts into a single national program.
- Define CI-KR and protection in the context of the NIPP.
- Identify the relevant authorities and roles of NIPP security partners.
- Describe how using the risk management framework ensures protection within and across CI-KR sectors.
- Identify the risk management activities implemented by NIPP security partners.
- Explain how the NIPP fosters information-sharing, provides guidance on the content of CI-KR protection-related aspects of homeland security plans, and helps to ensure a long-term effective, efficient CI-KR protection program.

Course IS-860 is available at http://www.training.fema.gov/emiweb/IS/is860.asp.

TSA also plans to develop and distribute a Security Awareness Training compact disc (CD-1) to interested pipeline companies.

As part of its Corporate Security Review Program, TSA has reviewed numerous pipeline systems, analyzing various aspects of each company's security programs. This process prompted development of CD-1, TSA having determined that improved security awareness training for pipeline company employees would be useful.

Besides making CD-1 available to pipeline companies that wish to use it, TSA will seek voluntary feedback from these companies and use the results to guide future pipeline transportation security initiatives.

TSA will conduct data collection for 2-3 years to allow for full distribution of CD-1 across the industry and for participating companies to complete full training cycles.

A mid-August 2006 security breach at KeySpan Corp.'s LNG facility in Lynn, Mass., prompted the US Pipeline and Hazardous Materials Administration to release an advisory reminding operators of LNG terminals, peak-shaving plants, pipelines, and other facilities of the need to implement security measures to stop intruders.

According to PHMSA, "Investigation revealed that the intruders had cut through the outer and inner perimeter fences and through the locked gate and gained access to the storage tank several days before the breach was discovered. A microwave intrusion system documented the intrusions on the computer monitoring system, which should have alerted operator personnel to the intrusion. Operator personnel did not respond. In the days following, personnel conducted several routine visual inspections of the area without noting the cuts in the fences. Although there was also video surveillance of the perimeter, personnel did not review the tape until they investigated the breach."

In this context, the need for training materials such as CD-1 is clear. But security is an ongoing process, and training materials need to be evaluated to ensure their effectiveness.

Assessing effects

TSA intends to use the information gathered in its survey of CD-1 users to assess the effect of the project on raising the baseline level of security awareness within the pipeline industry. It also hopes to gain an indication of CD-1 participation levels.

TSA estimates that an average of 300 companies/year will provide feedback on CD-1. It further estimates that the average time needed to respond to its survey will be 20 min. Done twice a year means 40 min/year spent on helping improve an industry-wide security awareness program.

Neither CD-1 nor IS-860 is by any means a panacea. Security, by its nature, is immune to such cures. But it is the 20 min budgeted here and there over the course of a year that will make a measurable difference. ✦

Megaprojects:

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Coming in June 2007, a PennWell Exclusive Supplement Highlighting the World's Leading E&C and Finance Companies.

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To participate in this project, contact:
Shawn Sejera at 918.831.9731 or ShawnS@PennWell.com, or call your local PennWell representative.

The US energy surge

The decision announced by US President George W. Bush last month to increase military strength in Iraq by 20,000 troops wasn't the only surge of January 2007. From initiatives during the month by both houses of Congress and the White House it is clear that the US government wants to surge back into the energy business.

This page previously addressed the initiatives individually (OGJ, Jan. 15, Jan. 22, and Feb. 5, 2007). But a full appreciation for what's happening on energy in the US requires a combined assessment. Consider:

- On Jan. 4, among its first acts with Democrats in control, the Senate passed a bill calling on Congress to require cuts in emissions of greenhouse gases, expand the use of specified types of energy, lower energy costs, eliminate "tax give-aways to large energy companies," and prevent "price-gouging, profiteering, and market manipulation."
- On Jan. 18, the House, also newly controlled by Democrats, passed a bill that would cut or repeal a range of tax and other incentives for the production or processing of oil and gas and spend the assumed savings on renewable and other alternative forms of energy. The bill also would coerce holders of Gulf of Mexico leases providing deepwater royalty relief uncapped by price thresholds, which were issued in 1998 and 1999, to renegotiate. Because some of the incentives under threat had been passed only recently, and because some of the targeted tax preferences remain available to other industries, the bill obviously aims to punish the oil and gas business.
- On Jan. 23, in his state-of-the-union speech, President Bush called for a 20% cut against projection in gasoline use by 2017 and an increase in the federal requirement for renewable and alternative fuel to 35 billion gal/year by the same deadline. Without providing details, he called for reform of vehicle fuel-economy standards. He also announced a doubling of capacity of the Strategic Petroleum Reserve to 1.5 billion bbl. On the same day, the Department of Energy began buying 100,000 b/d of crude for the reserve.

Look closely. It was just such a mixture of official groping that produced the National Energy Plan of 1977. For anyone who has forgotten or is too young to have known, that experiment in central energy planning failed. It failed spectacularly. It wasted public money and didn't deliver on its promises. It mainly enriched entrepreneurs with energy schemes that unfettered markets wouldn't support.

Motivations that led the US government into its energy mistakes of the 1970s have reemerged: recent experience with a run-up in oil and gas prices, anger at oil companies, anxiety over dependence on foreign oil, concern about the environmental effects of burning hydrocarbons, and political pressure from marketers of uneconomic fuels. Instead of oil from shale, the government now mongers ethanol from corn. Instead of smog, carbon monoxide, and other pollutants now impressively diminished as constituents of US air, politicians fret about global warming. But the motivations yield the same tactics: regulation of the quantities and forms of energy people use.

Those tactics failed before, and they'll fail again. Those tactics wasted Americans' money before, and they'll do so again. Americans never fare better on energy than they do when their government does nothing with energy markets except ensure that they work. History makes that clear to anyone clear-headed enough to see back past recent oil-price jumps.

The Senate's sense-of-Congress bill is political bluster, its hard talk about gouging and profiteering devoid of meaning, and its discussion about "reducing the burdens of consumers of rising energy costs" suggestive of price controls. The House bill is a political double-cross that, if passed, would only chase out of the country capital that US citizens need to see invested domestically in sound energy ventures. And the president's plans would squander money on expensive energy substitutes and unnecessarily hoarded crude oil.

Worst of all, these plans would rush the government back into a business about which it has learned nothing from past failure.

This is a surge Americans can't afford. ✦

Russia's drive for power—2: Gazprom controls gas exports to Europe, Asia

David Wood
David Wood & Associates
Lincoln, UK

Gazprom unveiled in September 2005 a short list of five foreign companies being considered as partners in Shtokmanovskoye, a supergiant gas-condensate field located in 350 m of water in the central part of the Barents Sea some 555 km east of Murmansk (see map, OGJ, Sept. 4, 2006, p. 70).

"Shtokman" clearly is a prize worth seeking. Its reserves are estimated at 3.7 trillion cu m of gas (131 tcf)—increased from 3.2 trillion cu m by the Russian Federation Nature Ministry's State Commission for Mineral Reserves in January 2006—and 31 million tonnes of gas condensate. It is the fourth largest gas field in the world, slightly larger than Hassi R'Mel field in Algeria, and the third largest in Russia. The supergiant Persian Gulf North field-South Pars field straddling Qatar and Iran holds 1,400 tcf, and Urengoy and Yamburg fields in Russia hold 220 tcf and 140 tcf respectively.

The first stage of Shtokman field development as originally conceived was expected to involve output capacity of about 30 billion cu m/year, with as much as 24 billion cu m/year targeted as LNG. About 15 million tonnes/year of the LNG was scheduled for export to the US. Capital cost of the first phase of the project was estimated at $10 billion, including gas extraction, liquefaction, and a pipeline to shore, and LNG shipping.

Production start-up was scheduled for 2010-12, and many expect the total development costs to exceed the quoted figure of $20 billion, which equates to just $1.09/boe, based on its gas reserves.

The companies short-listed in 2005 excluded Exxon, Shell, and the Japanese companies Mitsui and Mitsubishi, which were fighting to maintain production-sharing terms in the Sakhalin project. Those named on the Shtokman short list were Statoil ASA and Norsk Hydro ASA—companies that have since agreed to merge—and Chevron Corp., ConocoPhillips, and Total SA. Expertise gained from developing the Snohvit LNG project under construction in the Norwegian sector of the Barents Sea is considered important, and Statoil and Total have a clear advantage in that regard. In addition, Hydro has participated with Gazprom in drilling the fourth Shtokman field appraisal well.

Gazprom announced it would keep 51% of the project and would hold further talks to select a final lineup of two or three companies. Those talks lasted more than a year and involved each of the short-listed companies competing with each other to offer Gazprom equity shares in their international assets with strategic interest to Gazprom.

Revised Shtokman plan

In October 2006, however, Gazprom dismayed its foreign suitors by announcing that it was abandoning the bidding process and would develop Shtokman without any foreign equity partners under a plan that would export Shtokman gas by pipeline to Europe rather than export it to North America as LNG.[1] At that time Gazprom justified its action by saying the potential partners hadn't offered enough capital or attractive enough assets in return.

Under Gazprom's revised plan, gas initially will be piped from the field to the Russian coast, across Russia to the Baltic Sea, and onward from Russia to Germany through the now-sanctioned joint Russian-German 1,200 km Nord Stream pipeline, formerly called the North European Gas Pipeline. Gazprom owns 51% of Nord Stream, and BASF AG and E.ON AG hold 24.5% each.

Original plans also called for an LNG liquefaction plant near St. Petersburg; whether this will now be built remains uncertain. Pipeline operations, however, are scheduled to begin in 2010 with an initial capacity of 27.5 billion cu m/year with gas supplied from Siberia.

Capacity could be doubled with a parallel second line to be built in Phase 2.

In what appears to be recognition that Gazprom needs foreign deepwater operating expertise to develop the field, the gas monopoly announced that it had sent letters to the four companies on the Shtokman short list (reduced by the merger of Statoil and Hydro) offering them the possible opportunity to take part in the offshore development as contractors.[2] Needless to say, the companies have not responded to this announcement with enthusiastic press releases. Nevertheless, Gazprom is expecting talks with the companies to recommence this month.

Russia had hinted prior to October 2006 that US companies Chevron and ConocoPhillips would, in any event, be left out of the Shtokman project if the US precipitates deterioration in trade relations between the countries, and the gas would be redirected away from the US to Europe. This is the type of political leverage Russia can bring to bear when it controls access to gas needed by other countries.

Yet North America is a potentially valuable market for Russian gas. Despite the decisions apparently made on the export route for Shtokman gas, it remains clear that Russia and Gazprom remain keen to export LNG to the US.

They continue to take positions to enter that market. Gazprom has set up a trading company in the US—Gazprom Marketing & Trading US in Houston. It planned to sell five or more LNG cargoes in the US in 2006 under swap or purchase-and-resale schemes, some of which have involved BP and BG. This author therefore believes that LNG export facets to the Shtokman-Nord Stream projects are likely to reemerge.

Maintaining leverage

Russia wants to retain as much control as possible over its energy resources and export infrastructure. By doing so it knows it will retain the power that enabled it to cut off gas to Ukraine in early 2006, and consequently to parts of Europe, in a successful attempt to double the price of gas to Ukraine.[3] This tactic was successfully repeated in December 2006-January 2007 with Belarus. Such events must make potential customers downstream of Nord Stream—including North America—reflect upon their future security of gas supply and their potential vulnerability if becoming dependent on Russia for large volumes of gas.

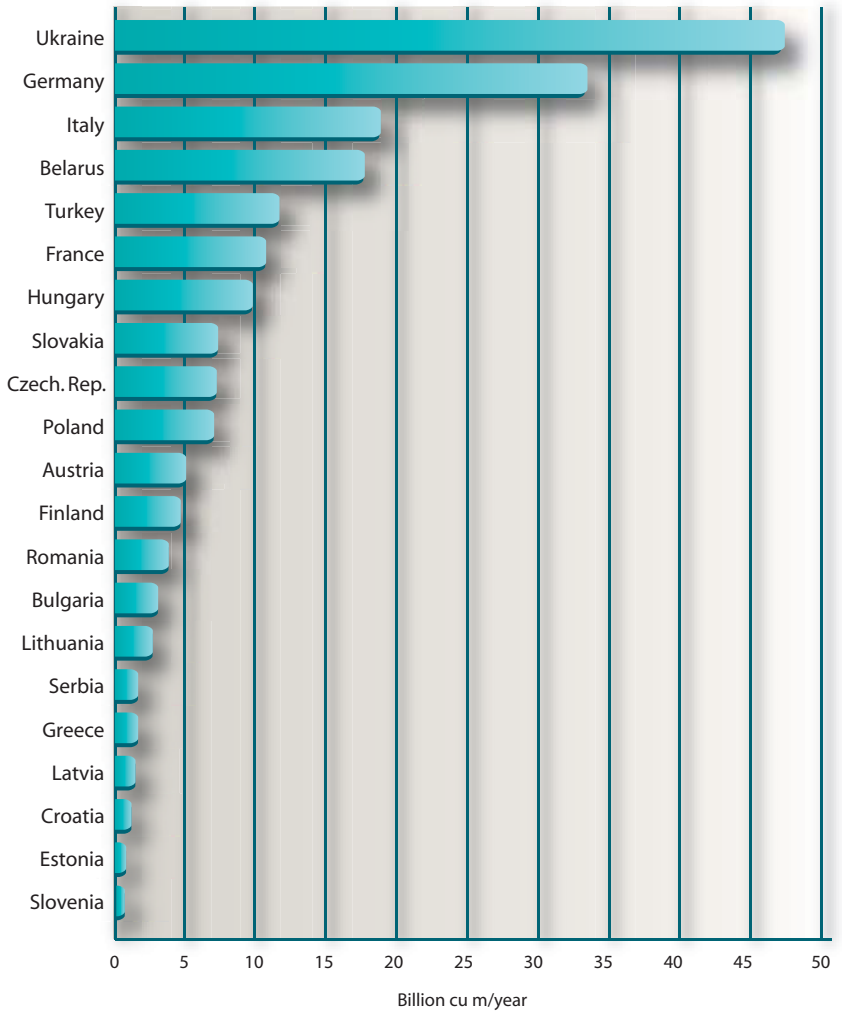
With or without US company involvement in Shtokman, much of the LNG eventually produced by that project and Baltic LNG projects under discussion would probably be destined for North American consumption. What is clear, however, is that Russia sees the Shtokman and Baltic LNG schemes as an opportunity to leverage more concessions from North American and European companies. It remains to be seen whether any operators will be tempted to sign up as contractors to Gazprom, however.

Markets becoming wary

Despite its dominance as the main supplier of natural gas to Europe, Russia does not have it all its own way, and it certainly has established a credibility problem with some of its main markets. Many European countries are now un-

GAS VOLUMES IMPORTED FROM RUSSIA

Fig. 1



Source: IEA, Centre for Eastern Studies Policy Brief, February 2005, David Wood & Associates

MAIN GAS EXPORT PIPELINES: RUSSIA-EUROPE[1]

Fig. 2

[1]Existing and planned lines. [2]Formerly North European Pipeline.
Source: "Security of Russian Gas Supplies to the EU—the Question of Infrastructural Connections," by Agata Loskot, a February 2005 policy brief of the Centre for Eastern Studies (Warsaw), David Wood & Associates

comfortable about being so dependent on Russian energy supplies, particularly gas.

The major Western European consumers of Russian gas include Germany, which depends on Russia for more than 32% of its supply, and Italy and France, which depend on Russia for about 25% of their gas (Fig. 1). The dependence of Eastern European countries on Russian gas averages some 73% of annual gas supply, with Lithuania, Latvia, Estonia, and Slovakia being completely dependent on gas from Russia.[4]

Since the gas supply interruptions of January and February 2006 caused by Russia's dispute with Ukraine, even Germany, Russia's most prized gas customer in Europe, is seeking supply security in diversity. Like Russia's other biggest customers, it is looking at alternatives to diversify its gas supply and guarantee supplies in the event of future pipeline disruptions.

Nord Stream is Russia's preferred solution as it avoids Poland and Belarus (Fig. 2). Germany sanctioned this in 2006. However, German energy companies are now openly seeking LNG import supplies and may even build their own LNG receiving terminal at Wilhelmshaven in the near future.

Asian markets sought

Russia has the opportunity to develop the vast untapped natural gas resources of Eastern Siberia to supply China's growing energy requirements and the thirsty markets of Japan and South Korea beyond.

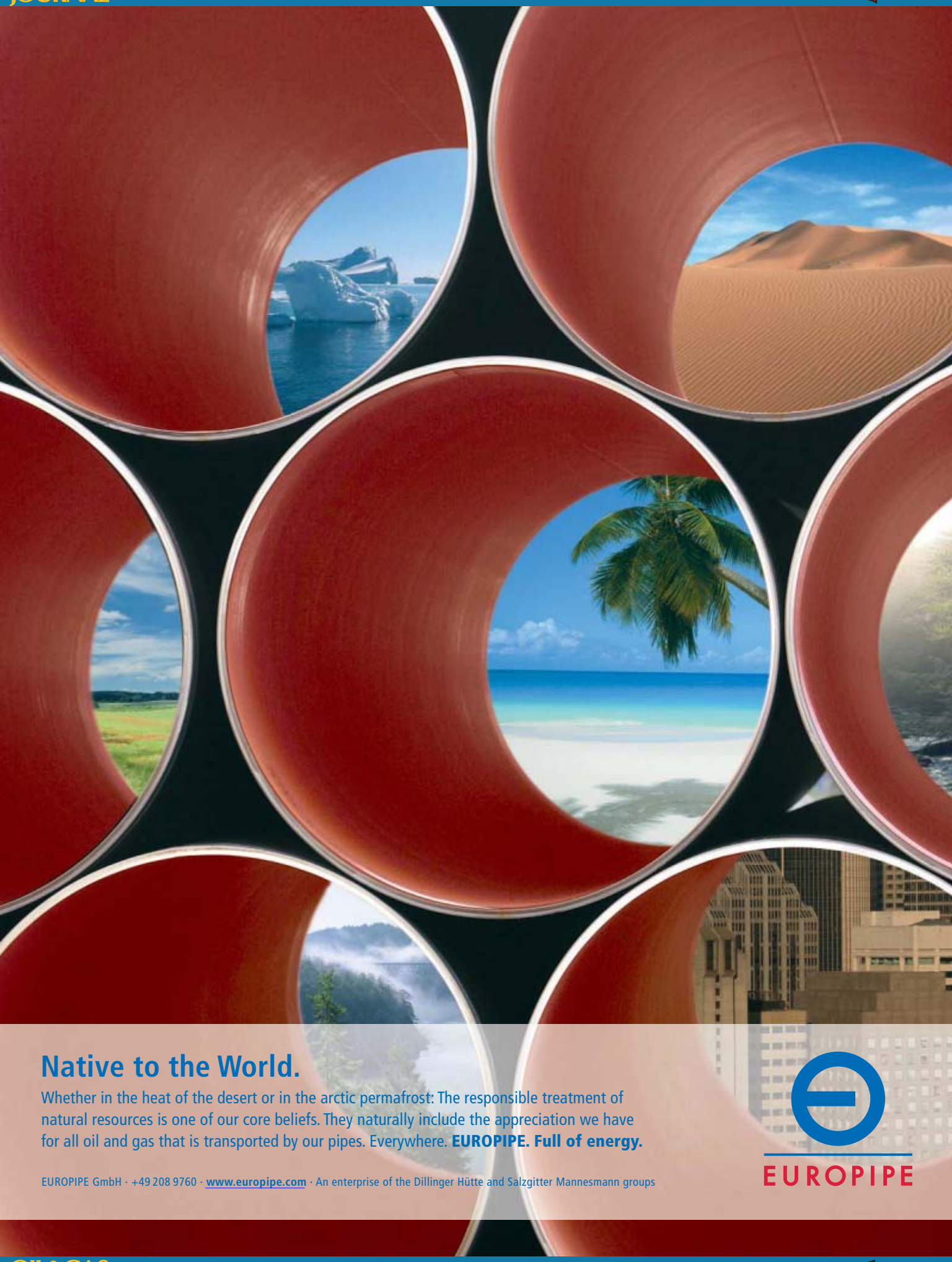
It would seem commercially expedient for Russia to commence these multibillion dollar infrastructure projects as soon as possible with a careful pipeline strategy integrating capital contributions from these key Far East customers and international oil companies (IOCs).

Indeed TNK-BP, as a holder of substantial stranded East Siberian gas reserves in Kovytka field, has been trying for several years to secure government approval to build a pipeline to China and potentially beyond to South Korea.

Kovykta field has gas reserves of 1.4 trillion cu m. A prefeasibility study has identified two potential routes for such a pipeline—an eastern route and a western route (Fig. 3). One, an $8.5 billion pipeline, would extend 2,645 km across Mongolia to Beijing and would include 22 compressor stations. The eastern option is a 4,485 km line extending across Ulan Ude and Chita to Beijing. This project would cost $10.5 billion and require about 37 compressor stations.

Each project has many engineering challenges associated with remoteness; varied terrain, such as permafrost, mountains, seismic zones, deserts, and wetlands; and protection of world heritage archeological sites such as China's Great Wall. TNK-BP has major political challenges to overcome as well, particularly with Gazprom, if it is to bring this gas to market.

TNK-BP and Gazprom have discussed and disagreed over the preferred pipeline route for several years. The eastern option opens up opportunities to ultimately deliver gas to Japan, but it would cost more and take longer to build. The short-term opportunities in China's gas market are what TNK-BP has been striving to unlock. In 2006 it was made clear that if such an export



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KOVYKTA FIELD POTENTIAL GAS EXPORT ROUTES* Fig. 3

*Based on a TNK-BP prefeasibility study completed in 2001.
Source: David Wood & Associates

pipeline is to be built, it will be under Gazprom's operatorship. And despite the commercial benefits this would bring to Russia's East, the government has stated that work will not commence until after 2012 and will be under Russian control.

The delay makes little commercial sense but may be explained in terms of control and geopolitics. Imposition of such an export time frame devalues the reserves for publicly traded companies such as TNK-BP and makes it more likely that the reserves will end up in Gazprom's hands at a low price in the medium-term.

Such maneuvering also inspires little confidence in the potential customers that they can expect Russian gas to solve their medium-term energy shortages. China is seeking LNG from a range of Far East suppliers and has entered into agreements with Iran for additional LNG volumes in the medium-term. Japan already has a well-established, diversified LNG supply base and is unlikely to replace much of that with pipeline gas from Russia unless very attractive, reliable, long-term prices are offered, which seems unlikely in the current energy market.

The Rosneft IPO case

In July 2006, Rosneft's initial public offering (IPO) was thought by many to be simply laundered assets of the Russian government's appropriations from Yukos, an existing publicly traded company. The flotation, with shares priced at $7.55, was one of the largest in history behind those of Japan's Nippon Telegraph & Telephone Corp. Mobile Communications Network (some $18.36 billion), Enel SPA, Deutsche Telecom, and Bank of China. The group raised $10.66 billion through the flotation, the biggest in Russian history, which valued the firm at $80 billion. Rosneft shares, traded on the London Stock Exchange, increased progressively in price to $9.50/share from about $7.50/share between September and December 2006 and were trading around $8.90/share on Feb. 9, 2007.

The controversy, including a failed, last-gasp UK court challenge by Yukos to prevent the IPO from proceeding, concerns Rosneft's acquired Yugansk oil unit. Rosneft bought Yugansk in 2004 after it was seized from Yukos and auctioned off to settle a disputed unpaid tax bill. Yukos has been gradually dismantled over the past 2 years and is in the middle of bankruptcy proceedings in Russia. Indeed, Andrei Illarionov, one of Putin's own economic advisors, referred to the affair as the "robbery of the century."

The initial price tag for the shares was above market expectations, ignoring the risks of investing in a country where the rule of commercial law can be flouted for purposes of political expediency. Yukos essentially lost its fight to survive on Sept. 19, 2006, when a Moscow arbitration court of appeal upheld an Aug. 1 court ruling declaring it bankrupt.

Many believe that it was the overt political ambitions of Mikhail Khodorkovsky, the jailed founder of Yukos, which led to the dismantling of this company, formerly Russia's biggest crude oil producer. Russian authorities argue that Yukos was guilty of huge fraud and tax evasion and that they pursued it rightfully for money owed to the state. The problem with this argument is that the Russian government did not pursue companies owned by other oligarchs with similar histories and accounting practices.

In these circumstances it is understandable that many foreign institutional investors declined to subscribe to Rosneft's IPO. Some 50% of the uptake involved just four buyers—Malaysia's national oil company Petronas, China's CNPC, BP, and a group of investors represented by Gazprombank—and it was declared to be "oversubscribed." This gave the IPO the appearance of a dressed-up private placement. The IOCs involved clearly concluded that the access to reserves granted by this opportunity outweighed the uncertainty of the government interventions and manipulations ahead, which could erode much of the future value they should expect from a holding in Rosneft.

Gazprombank purchased its $1.2 billion in Rosneft shares on behalf of three of Russia's richest oligarchs: Roman Abramovich, Vladimir Lisin, and Oleg Deripaska. The participation of these oligarchs helped to ensure that the IPO was oversubscribed and to demonstrate that it had the support of a substantial sector of Russian business. In February Gazprom announced it had received concrete expressions of interest from large US companies in the acquisition of assets formerly owned by Yukos as court-appointed receivers prepare to

liquidate its remaining assets. No US company has yet confirmed such interest.

There are few countries in the world in which the Yukos and Rosneft outcomes would not be challenged in a robust way both politically and legally. The precedent is disturbing. Because they succeeded with it once, and have been emboldened by the outcome, few can expect similar events not to occur in the future. Whenever the Russian government becomes short of funds in the future, say if an oil or gas demand or price collapse occurs, Russian publicly traded companies had better beware. Also IOCs with attractive assets linked with strategically important export infrastructure may have to negotiate hard and accept erosion in their equity participations in order to avoid appropriations. Caveat emptor! ✦

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Producers facing dramatically higher capital costs

The costs of major oil and gas production projects have risen more than 53% in 2 years, and no significant slowing is in sight, said a benchmark index developed by IHS and Cambridge Energy Research Associates (CERA).

The IHS-CERA Upstream Capital Costs Index (UCCI) tracked nine key cost areas for offshore and land-based projects. The UCCI climbed 13% to 167 during the 6 months ending Oct. 31, 2006, compared with an increase of more than 17% in the previous 6 months.

Since 2000, the UCCI has risen 67%—with most of the increase in the last 2 years—while the Producer Price Index-Commodities for finished goods (excluding food and energy) moved up 7.5% during the same period.

The continuing cost surge is central to every energy company's strategic planning, analysts said.

CERA Chairman Daniel Yergin said, "Rising capital costs rank right alongside more widely recognized issues such as world market trends, geopolitics, globalization, and new technologies at the top of the agenda for the energy industry."

An all-in measure of project costs, the UCCI is up 53% since the end of 2004. While strong commodity prices are expected to continue, this rise in costs is causing firms to reevaluate the economics and viability of many projects.

Index data

The UCCI is a model based upon a portfolio of upstream projects worldwide. Cost engineering software was used to predict costs for those projects. Analysts plan to update the UCCI every 6 months and probably release updates in May and November.

The UCCI tracks the costs of equipment, facilities, construction materials, and personnel in more than 24 onshore and offshore oil and gas development projects. Specific projects in the portfolio were not disclosed.

The UCCI is similar to the Consumer Price Index (CPI) in that it provides a tool for tracking and forecasting, Yergin said.

Richard Ward, CERA senior director and UCCI project manager, said 2007 is shaping up to be a year of additional increases.

"Despite a slight slowing in the rate of increase during the 6 months to Oct. 31, we expect project capital costs to continue reaching new record levels during 2007," Ward said. "With high oil prices driving new development projects, capacity constraints continue to support increases in the cost of equipment and services."

The analysis shows capacity is tight in all markets, Ward said. Hot spots for capacity constraints are the deepwater regions, such as West Africa and the Gulf of Mexico.

"While oil prices stay above $55/bbl CERA expects that confidence to remain. Should prices slip below $50/bbl, the industry should expect some expansion projects to be canceled or delayed," he said.

Deepwater projects experienced the largest cost increases, rising 15% in the last 6 months. Ward attributed cost increases to rig rates, technology limits, and skills requirements. These costs are expected to continue to rise due to tight industry capacity.

Onshore facilities, including LNG, have seen the slowest rates of increase, 12%, he said.

"Higher costs, combined with the recent drop in gas prices, have made some projects uneconomical and triggered a reevaluation of plans." Ward said. "This has produced a slight relaxation of tight support service or commodity markets, particularly in the US."

Cost drivers

Of the nine primary drivers of project capital development costs, steel is the only segment to decline over the past 12 months, primarily because steel prices began accelerating globally before the recent increase in oil prices and demand.

Most of the others—except equipment and bulk materials—are specifically focused on the oil and gas business and are at near maximum capacity.

The primary drivers are:

- *Steel.* With oil industry steel less than 2% of total steel production and special mill runs required for oil indus-

try grade steels, the industry faces premium pricing and constrained capacity.

• *Offshore rigs*. A rush by drilling contractors to expand their fleets has produced plans for construction of over 100 new rigs during the next 4 years. If demand stays high, the majority of these rigs will come to market and some additional rigs may begin construction. This should ease rates, but not until mid-to-late 2009. Because drilling accounts for 40% to 50% of development costs, a 25% rise in the rig rate can produce a 10% or larger increase in total project cost.

• *Equipment*. The market for long lead time oil and gas equipment—such as generators, compressors, vessels, towers, and exchangers—is very tight with extended delivery times and premium pricing.

• *Yards and fabrication*. Specialized, oil and gas fabrication encounter premium pricing in competition with container demand and also cruise ship demand. Yards are at capacity. Even with an expected 15% expansion by 2012, utilization will remain high as will demand for LNG tankers.

• *Offshore installation vessels*. Plans announced by pipeline installation companies to expand capacity of the current 56-vessel fleet by 8%, or three new vessels, is insufficient to meet short-term demand. The world's fleet of 26 heavy lift crane vessels is projected to expand by one in 2009, increasing total lift capacity by about 15%. If demand for installation projects should soften due to a decline in oil prices, previously delayed decommissioning projects are likely to claim the available capacity at reduced rates.

• *Design and project management*. Although vigorous efforts to attract new talent into the detailed design arena, particularly in Asia and the Middle East, CERA anticipates at least 5 years will be required for the new entrants' experience to reach the level required.

Analysts expect design and project management costs will escalate until then. Meanwhile, specialists in deepwater, subsea, and project management will receive premium pay. ✦

Execs discuss global warming with Turner, Wirth

Paula Dittrick
Senior Staff Writer

Energy executives met in a Feb. 7 roundtable discussion with billionaire businessman Ted Turner and Timothy E. Wirth, president of the United Nations Foundation and former US senator from Colorado, to discuss global warming.

"What interests me is watching the behavior of the large oil companies," Wirth said. "They are moving in the

right direction," he told reporters at a news conference after he and Turner addressed a Houston World Affairs Council luncheon.

The United Nations Foundation was formed after Turner donated $1 billion in 1997 to support UN causes and to help address key global challenges

BP PLC, Shell, Marathon Oil Corp., and ConocoPhillips executives were among 25 people who attended a roundtable meeting with Turner and Wirth before the luncheon discussion, moderated by investment banker Matt Simons, chairman of Simmons & Co. International.

Wirth said the message from energy executives during the roundtable meeting was that the government needs to "get the rules right [on greenhouse gas emissions] and then let us go." Simmons noted what he called "50 years of energy mistakes" under eight presidents.

Momentum is building for worldwide support to cap GHG emissions, Wirth said, particularly carbon dioxide. He said the environmental movement "has dramatically matured" since the Clean Air Act was implemented during the 1990s.

"I wish that were the case with the political environment today," Wirth said, adding that it's "going to be hard" to reach a consensus in the US Congress. "We have to break down some old thinking on Capitol Hill."

The major GHG negotiation globally will be about which countries get the right to pollute and what volumes of pollution from which countries will be acceptable, Wirth said.

Turner's fuels

Turner said the private sector can help the government, and he predicted that clean renewable energy "is going to make a fortune." He said: "The day of fossil fuels as a fuel are over. It's just a matter of how soon everybody recognizes it. We only have one atmosphere."

Saying his favorite forms of alternative energy are solar and wind, Turner told reporters that he recently invested "millions" of dollars in DT Solar, formerly Dome-Tech Solar, of Branchburg, NJ.

"I think dealing with climate change is going to be the biggest single challenge humanity has ever faced, and we're facing it now," Turner said. "I'd rather have a nuclear plant than a new coal plant the way they are now."

He and Wirth called for advances in CO_2 sequestration. ✦

IP Week: Saudis reveal spending plans for next decade

Uchenna Izundu
International Editor

Saudi Arabia will spend $507 billion on energy and infrastructure projects over the next 11 years, a Saudi government official said Feb. 12 at the International Petroleum Week conference in London.

The kingdom will spend about $267 billion on its oil, gas, and chemical businesses and $240 billion on developing minerals, environmental technologies, infrastructure, power, and water. "Deliverability is the issue for oil and gas, and not supply," said Saud Al Amnari, minister plenipotentiary at the Saudi embassy in the UK. Speaking in place of Saudi Ambassador to the UK Prince Mohammed bin Nawaf, he pointed out that Saudi Arabia has about 100 years worth of reserves to tap and meet future global demand. Its crude reserves stood at 259.8 billion bbl at yearend 2005.

Saudi Arabia is committed to using diplomacy in handling Iran and its uranium-enrichment program, which is causing anxiety worldwide, Amnari said, adding that it was vital that there is peace in the Middle East to ensure stable petroleum supplies. "Iran is important because it holds up to one tenth of the world's oil reserves, is the second-largest holder of gas reserves, and occupies a strategic location. We need genuine brokers of peace to bring stability to the region."

Meanwhile, Saudi Aramco plans to expand its production capacity to 12 million b/d by 2009 and its worldwide refining capacity to 6 million b/d over the next 5 years. With high oil prices dampening global demand, Ibrahim S. Mishari, Aramco vice-president, marketing and supply planning, said it has not revised its production capacity figures.

Aramco will focus on expanding its resources base through discoveries and improving its recovery rates from fields, Mishari said.

Aramco will be a key player in providing global oil supplies but varied estimates on world energy demand make it hard to predict how much it will contribute in 2030. According to some forecasts, there will be a 50% increase in world energy needs by 2030, while others say 60%. The predicted call on Saudi oil ranges from 11-20 million b/d of oil.

"That 9 million b/d difference presents big producers like Saudi Arabia with a difficult balancing act since underinvestment in capacity will result in price spikes and supply shortages, while overinvestment will drain substantial amounts of capital from the Kingdom's other economic needs," he said.

A key priority for the petroleum industry is to hire sufficient competent individuals who can drive technological developments, Mishari noted. About 40-60% of the industry's workforce are eligible for retirement, and another wave of retirees is on their heels within the next decade or so—but unlike the past, there are not enough new graduates to replace them.

Mishari told OGJ there are a number of initiatives under way in Saudi Arabia

to encourage new recruits, including scholarships, sending students abroad, on-the-job training, and working with universities to set the curricula. ✦

IP Week: Europe will still receive Russian natural gas

Uchenna Izundu
International Editor

Fears that Russian gas exports will be sent to other markets such as China instead of Europe are overstated, said Julian Lee, senior energy analyst at the Centre for Global Energy Studies, speaking Feb. 14 at the International Petroleum Week conference in London.

"Europe and Russia share [an] oil-related gas pricing philosophy that China doesn't have," he said about the security of European gas supplies. "In China, gas would compete with coal, and there is a big gulf between what China will pay and what Russia wants to charge for its gas."

China is seeking Russian gas, and Russia has proposed building two 30-40 billion cu m/year gas pipelines from Western Siberia to China that could be commissioned from 2011. However, progress on the initiative has been just talk so far, Lee said.

"I think the worries about gas going to China are overstated," he emphasized, pointing out that Sakhalin LNG has been contracted by Japanese and Korean buyers, not China.

Lee said Europe was a very important market for Russia and was its biggest customer; Europe imports about 25% of its gas from there.

The current form of the Energy Charter Treaty, an international agreement that aims to protect foreign energy investments, has caused a standoff between Russia and the European Union. Russia, arguing that the treaty does not serve its interests, has refused to ratify it because the gas giant is un-

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Lease billing moves online

The US Minerals Management Service's proposed budget for fiscal 2008 includes $1.45 million for the first of a 2-year initiative to institute an interactive payment reconciliation and billing system. There's more to it than leaseholders not getting away with saying the check is in the mail.

To a great extent, they can't do it now. MMS collects fees and royalties not only for its own federal leases but also for those issued by the Bureau of Land Management and American Indian tribes, said Lucy Denett, MMS's associate director for minerals revenue management. Reconciling payments with outstanding balances can be challenging. It involves close to 29,000 producing oil and gas, coal, geothermal, and other leases. There also are separate "lines" when a lease produces more than one commodity. Leases also can have three or four partners, each reporting and paying. Finally, lease terms can vary by location and the issuing agency.

The result is more than 600,000 fee and royalty lines for MMS's Minerals Royalty Management (MRM) division to process each month. "We're a major collection and auditing operation," Denett told OGJ.

Payments, reports

She said the system already is automated, with 99% of the total payments made as electronic fund transfers directly to the US Department of the Treasury. MRM simultaneously receives a report and has to match that information with payments received. Both are due within 30 days. MRM then has 30 additional days to disburse shares to states or tribes.

The process requires a myriad of internal controls to work. If a report and payment differ, an MRM auditor telephones the lessee to discuss the discrepancy. MMS is seeking the money to improve this part of the operation so a lessee and an MRM auditor can simultaneously examine submitted documents and payments on their own computers. A discrepancy may not be the lessee's fault; sometimes an agency has neglected to set up the correct account to receive the payment.

"The more automated and transparent we are, the better the process will be," Denett said.

Both sides benefit

Moving this reconciliation process online should benefit both parties, she suggested. "A company may have thousands of lines and get a bill from us filled with information," she said.

Once adopted, the new system would signal when a basic error such as incorrect lease numbers, omitted production or financial information and incorrect addition occurs. The report would then be automatically rejected and returned with missing areas highlighted.

Denett said MRM has been working with the Council of Petroleum Accountants Societies and the Department of the Interior's royalty policy committee and royalty taskforce to develop the improvements.

"Companies have been asking for this. There are so many leases, so many lines, so many adjustments. We need to be able to communicate, share information where appropriate and make sure payments are being made and processed correctly," she said. ✦


Lost?

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Oil at center of nuke talks

Everyone knows that oil is the tool of choice where diplomacy is concerned, particularly in these days of a reactive market and supposedly depleting supplies. Look at the oil deal North Korea has just won.

Envoys from six nations—the US, Russia, China, Japan, and the two Koreas—have reached a tentative agreement early last week on the first steps toward North Korea's nuclear disarmament, and oil was at the heart of the discussion.

Details of the agreement have yet to be made public, but it is said to resemble the bargain reached in 1994 during President Bill Clinton's administration when North Korea pledged to freeze and eventually dismantle its reactor at Yongbyon in return for 500,000 tonnes/year of heavy fuel oil.

In the wait for further revelations of the latest deal, one thing is abundantly clear: The North Koreans wanted oil badly and bargained hard to get it without giving up too much.

Talks falter

Indeed, the Chinese-sponsored negotiations apparently had faltered for several days over what diplomats said were North Korean efforts to secure large amounts of energy aid but to avoid corresponding denuclearization steps.

According to diplomats involved in the talks, however, the first step in the process does call for North Korea to close down its nuclear reactor at Yongbyon and readmit international nuclear inspectors in exchange for energy aid.

The diplomats would not immediately say just how much energy aid North Korea would receive in the new bargain—it apparently had demanded large quantities of heavy fuel oil, reportedly up to 2 million tonnes—or describe the precise schedule that would tie fuel deliveries to closure of the Yongbyon reactor.

While the agreement is expected to help prevent new nuclear development by North Korea, it does not take up such issues as Pyongyang's past uranium enrichment for nuclear weapons development, the closure of nuclear testing facilities, or its missile development program.

"Left for later" is the phrase diplomats use to describe the issue of North Korea's existing nuclear weapons and the plutonium fuel already produced at Yongbyon—estimated by US experts as enough to make 8-10 bombs.

Bomb by bomb

Thus, some say, the latest agreement may mark a step forward, but it does not eliminate the possibility that Pyongyang may use its existing nuclear weapons as a bargaining chip during future talks. Can't you just see it now? The amount of oil goes up bomb by bomb.

As one observer put it, North Korea is not likely to relinquish its nuclear capabilities too easily because of the belief that they are the last card that the country's leader, Kim Jong-il, has to ensure survival of his regime.

Meanwhile, others are taking their cue from the North Koreans. "Generating nuclear energy is necessary in view of the depletion of oil reserves," according to Iranian Ambassador to Algeria Hossein Abdi Abyaneh. ✦

comfortable with the Transit Protocol, a related document that facilitates the transit of hydrocarbons. Lee told OGJ that the Energy Charter Treaty needs to be revamped because it was based upon a bygone era when the West assumed that countries within the Commonwealth of Independent States were in need of investment to develop energy infrastructure. "The world has moved on from that position," Lee said. "Russia is not in need of Western companies and technology, because these can be brought in with service companies, and Russia is awash with petrodollars. The Energy Charter Treaty needs to be more balanced with its needs." ✦

EPA targets benzene in its new regulations on toxic emissions

Nick Snow
Washington Correspondent

The US Environmental Protection Agency Feb. 9 enacted new Mobile Source Air Toxics regulations designed to significantly decrease toxic fumes from gasoline, vehicles, and fuel containers.

The new rules join fuel and vehicle standards already in place in aiming to reduce toxic emissions from cars and trucks to 80% below 1999 levels, EPA Administrator Stephen L. Johnson said as he signed the latest order.

Essentially, the new MSAT regulations toughen benzene standards for gasoline, set hydrocarbon emission standards for cars at cold temperatures, and require fuel containers to be tighter to prevent evaporation of harmful fumes, EPA said.

It said that once the new standards are fully implemented by 2030, they are expected to reduce MSAT emissions by 330,000 tons/year, including 6,000 tons/year of benzene.

EPA said it expects the vehicle standards to produce $6 billion/year of health benefits from particulate matter

reductions by 2030. It said that the entire rule will result in an estimated cost of $400 million/year in 2030.

The regulations' fuel section lowers the allowable benzene content in gasoline nationwide to an average 0.62 vol % beginning in 2011 from its current level of 1.0 vol %. The limits apply to both reformulated and conventional gasoline. Gasoline sold in California will not be affected because the state already has implemented its own stringent standards similar to what EPA is establishing, the federal agency said.

The fuel regulation includes a nationwide averaging, banking, and trading program. EPA said that in addition to the 0.62 vol % standard, refiners and importers will have to meet a maximum average benzene standard of 1.3 vol % beginning July 1, 2012.

Much less variation

EPA said the regulation should lower benzene levels in all areas of the country and result in significantly less geographic variations. Regions where benzene levels currently are highest, such as Alaska and the Northwest, will experience the biggest reductions, it predicted.

The agency said it would "provide special compliance flexibility for approved small refiners or any refiner facing extreme unforeseen circumstances."

For vehicles, the regulations aim to reduce benzene and other nonmethane hydrocarbon (NMHC) exhaust emissions by tightening current test procedures which often do not control such emissions at temperatures below 75° F.

The new rule will establish a sales-weighted fleet average for each manufacturer's cars and trucks of 0.3 g/mile for vehicles weighing 6,000 lb or less, phased in from 2010 through 2013. Heavier vehicles, including trucks weighing up to 8,500 lb and passenger vehicles up to 10,000 lb will have to meet a 0.5 g/mile sales-weighted NMHC average, phased in from 2012 through 2015.

"A credit program and other provisions provide flexibility to manufacturers, especially during the phase-in periods," EPA said.

Rule for containers

The new regulations also establish standards to limit hydrocarbon emissions that evaporate from or permeate through portable fuel containers. The rule applies to containers for kerosine and diesel fuel as well as gasoline.

Starting with containers manufactured in 2009, allowable evaporation or permeation emissions will be limited to 0.3 g/gal/day, EPA said. "We are also adopting test procedures and a certification and compliance program in order to ensure that containers will meet the new emission standard over a range of in-use conditions."

EPA said it has worked closely with major container manufacturers, and it anticipates that new cans will be built with a simple and inexpensive permeation barrier and new spouts which will close automatically.

National Petrochemical & Refiners Association Vice-Pres. Charles T. Drevna said the trade group is reviewing EPA's new regulations "with close attention to its potential impact on gasoline supply."

The order further tightens gasoline specifications, especially for conventional gasoline, which represents about two thirds of the nation's total supplies, he noted Feb. 9.

"EPA has incorporated averaging, banking, and trading. However, part of the rule does not permit the use of credits. This constraint is a concern for some refiners. In addition, this will have different impacts on individual refiners," Drevna said. ✦

El Paso to pay $7.7 million for oil-for-food irregularities

Sam Fletcher
Senior Writer

Without admitting any wrongdoing, El Paso Corp. said Feb. 7 it will forfeit $5,482,363 and pay a civil penalty of $2.25 million to the US Securities and Exchange Commission in connection with illegal surcharges paid to Saddam Hussein's government for Iraqi oil under the United Nations' oil-for-food program.

In return, the company faces no federal prosecution, said representatives of the US Department of Justice. The forfeited $5.5 million will be transferred by the US through the UN's Development Fund of Iraq as restitution to the citizens of Iraq.

Coastal Corp. was involved in the oil-for-food program starting in 1996, prior to El Paso's acquisition of the company in 2001, and participated in the program until May 2002. "Following 2000, neither Coastal Corp. nor El Paso purchased any Iraqi oil directly from the government of Iraq under the program," said El Paso officials. Iraqi government records obtained by DOJ showed nearly $5.5 million in illegal surcharges were paid "by the third parties that purchased the oil directly from the government of Iraq under the program or by other third-party intermediaries" from June 2001 until May 2002. "Although El Paso took steps designed to prevent the purchase of Iraqi oil from third parties on which illegal surcharges had been paid, such procedures proved to be inadequate," said the company.

SEC officials paint a darker picture of the company's activities, however. SEC officials reported: "El Paso failed to maintain an adequate system of internal controls to detect and prevent the payments. Although El Paso inserted a provision in some contracts requiring the third party to represent that it had not paid surcharges, El Paso failed to conduct due diligence to ensure that

surcharges were not paid. Recorded conversations reveal El Paso's knowledge that the provision was entirely ineffective. In one conversation, a third party that indicated he was willing to pay illegal surcharges to Iraq indicated that he would be equally willing to sign a false certification denying the payment. El Paso's accounting for its oil-for-food transactions failed properly to record the nature of the company's payments. In at least 15 transactions, a portion of the company's price for oil constituted kickbacks to Iraq. The company failed to so designate those payments, characterizing them instead simply as part of the cost of goods sold."

The UN oil-for-food program was intended to provide humanitarian relief for the Iraqi population under international trade sanctions. In August 2000, however, officials of Iraq's State Oil Marketing Organization (SOMO) began demanding illegal kickbacks on sales of crude through that program. The kickbacks were made in the form of surcharges and were sent to Iraqi-controlled accounts at banks in Jordan and Lebanon.

Coastal received its first surcharge demand in September 2000. According to the SEC, "An El Paso consultant and former Coastal official arranged a $201,877 surcharge payment on the company's behalf, which was made to an Iraqi-controlled account at Ahli Bank in Jordan." That former official was not named in the SEC statement.

Oscar S. Wyatt Jr., former chairman of Coastal, was indicted by DOJ in 2005 on four counts of wire fraud and engaging in prohibited financial transactions with Iraq.

After being notified by SOMO that all oil contracts would include surcharges, El Paso ceased direct purchases from SOMO but continued purchases through third parties. "Beginning in June 2001, El Paso entered into 14 additional third-party transactions involving 15 contracts to purchase some 21.4 million bbl of oil. Approximately 25-30¢ of every barrel [price] was illegally kicked back to Iraq by third parties. El Paso's oil traders had to factor the surcharge into their oil price, and there are recorded conversations of the company's officials and traders discussing the surcharges," said SEC officials. "El Paso knew, or was reckless in not knowing, that $5.5 million in illegal surcharges were made on those contracts and passed back to El Paso in premiums." The SEC filed Foreign Corrupt Practices Act books and records and internal controls charges against El Paso in the US District Court for the Southern District of New York.

El Paso voluntarily ceased its trade in Iraqi oil under the oil-for-food program in mid-2002 "based, in part, on concerns about the effectiveness of compliance efforts in preventing the payment of illegal surcharges by others to the former government of Iraq," said government officials. That was a factor in the government's decision not to pursue criminal charges against the company. Another factor is that company employees involved in the surcharge activity are no longer employed by El Paso.

As part of the settlement, El Paso agreed to continue to cooperate with federal authorities in their ongoing investigation of illegal activity under the UN program. It also is enjoined from future violations of certain sections of the Securities Exchange Act of 1934. ✦

BP refinery leads US in carcinogenic emissions, group says

Nick Snow
Washington Correspondent

Nine US refineries account for only 15% of the nation's total capacity but represent one third of the carcinogenic emissions reported by the oil industry, according to a report released Feb. 8 by the Environmental Integrity Project.

In the report entitled "Refined Hazard: Carcinogenic Air Pollution from America's Oil Refineries," BP America Inc.'s Texas City, Tex., facility led EIP's list of refinery carcinogenic emissions in 2004.

BP's plant was followed by facilities owned and operated by ExxonMobil Corp. in Baytown, Tex.; Flint Hills Resources LP in Corpus Christi, Tex.; La Gloria Oil & Gas Co. in Tyler, Tex.; Lyondell Houston Refining LP in Houston; ExxonMobil in Baton Rouge, La.; Valero Energy Corp. in Corpus Christi; Sunoco Inc. in Philadelphia; Chalmette Refining LLC in Chalmette, La.; and Citgo Petroleum Corp. in Lake Charles, La.

EIP Director Eric Schaeffer, who started the organization in March 2002 after resigning as director of the US Environmental Protection Agency's Office of Regulatory Enforcement, said major inconsistencies in the carcinogen emissions data analyzed in the report raise serious questions about the accuracy and completeness of oil industry reporting to EPA.

"What we are really seeing here are the shortcomings in the 'honor system' for reporting these emissions. Overall level of emissions of carcinogens declined between 1999 and 2004, but there were big jumps at some refineries and inconsistency in the quality and level of reporting at others. EPA should stop taking industry self-reporting at face value, and investigate whether these emissions are being accurately reported as the law requires," he maintained.

Database flaws

The National Petrochemical & Refiners Association promptly challenged that conclusion. "The report simply correlates Toxic Release Inventory (TRI) information to existing petroleum refineries. Unfortunately, the report does

not control for the significant shortcomings of the TRI database, including its failure to weigh emissions according to actual risk," NPRA Executive Vice-Pres. Charles T. Drevna said.

"Emissions included in the TRI are permitted releases, which have a predetermined level that does not pose an unacceptable risk to human health and the environment," he noted.

EPA Press Secretary Jennifer Wood said the agency is committed to holder polluters responsible, and that its enforcement has resulted in 17 settlements since 2000 that account for 77% of the nation's total refining capacity. These settlements, Wood said, cover 85 refineries in 25 states and will result in emissions reductions of 80,000 tons/year of nitrogen oxides and 235,000 tons/year of sulfur dioxide.

Negotiations are continuing with other refiners representing another 11% of total US refining capacity and other investigations are currently under way, according to Wood.

An ExxonMobil representative said the company was still studying the EIP report and could not comment on its contents. "ExxonMobil refineries are generally world-scale in size, with the Baytown and Baton Rouge facilities being among the largest in the US. Since TRI reporting began in 1988, ExxonMobil has reduced air emissions of the referenced compounds by 36%," said Prem Nar, who handles downstream public affairs for the company.

EIP said its report, which is available online at environmentalintegrity.org, uses data from the EPA TRI to catalogue refinery air emissions of certain pollutants that are known or believed to cause cancer. It said TRI is a database that contains information on toxic chemical releases reported annually by certain covered industries, including refineries.

Designations of chemicals as carcinogenic or possibly carcinogenic in humans are made by expert consensus groups established by the US National Toxicology Program, or by the International Agency for Research on Cancer, which is an agency of the World Health Organization. The carcinogens emitted by US refineries include benzene, ethylbenzene, butadiene, poly-cyclic aromatic hydrocarbons (PAHs), naphthalene, formaldehyde, and metals such as nickel and lead, according to EIP.

Biggest single source

The report said that BP's Texas City refinery was the largest single refinery source of carcinogen emissions in 2004, due mostly to its reported release of nearly 2 million lb of formaldehyde in that year. BP has claimed that the formaldehyde release resulted from a change in its emission calculations, raising questions as to whether other refineries are reporting accurately, EIP said.

Excluding that refinery, the group

said that Texas refineries accounted for 36% of total refinery air emissions of carcinogens in 2004, but only 24% of the nation's refining capacity. In the aggregate, Texas refineries emitted two and a half times the volume of carcinogens per barrel of oil as did California refineries in 2004, it said.

It said that LaGloria's plant in Tyler was the largest individual US refinery source of benzene air emissions, while Sunoco's Philadelphia installation was the largest emitter of PAHs.

Noting that EIP's report cites benzene emissions, NPRA's Drevna said trends for benzene at 95 urban monitoring sites around the country show, on average, a 47% drop in benzene levels in recent years.

"Toxic emissions have declined in part because of actions taken by the refining industry. First, advanced technology and management systems at refineries and petrochemical facilities have lowered emissions. And second, the introduction of new refinery products—namely cleaner gasolines—has reduced the toxics profile of cars and trucks. These reductions will be even more pronounced when the Phase II Mobile Source Air Toxics rules are implemented over the next several years," Drevna said. ✦

Brazilian E&P boom increases investment opportunities

Peter Howard Wertheim
OGJ Correspondent

Oil and gas exploration and production activities in Brazil will increase in the upcoming years as the country beefs up its self-sufficiency efforts. Foreign companies alone are expected to invest $25 billion in E&P during 2007-11.

At least 20 new platforms will be operating by 2010—13 in the Campos basin, which is responsible for 80% of the country's production. Production from the basin averages 1.8 million b/d of oil.

Offshore E&P contributes 81% of Brazil's oil and gas production. About 90% of Brazil's proved oil reserves are offshore, with 64% of the concession areas in deep and ultradeep waters, according to state-owned Petroleo Brasileiro SA (Petrobras). Research and exploration areas under license include Ceará-Potiguar and Camamu-Almada, in Bahia state, but Espírito Santo and Santos also are proving great stages for new business deals, said Petrobras.

There are 15 offshore fields showing commercial oil and gas in the Potiguar basin—7 already in production and 8 under development. Petrobras's Siri field and the Guajá and Salema Branca fields on Block BPOT-100A have been declared commercial and are being developed. Exploration is under way and will continue until 2009 on two additional blocks, BM-POT-11 and BM-POT-13.

In 2006-10, Petrobras plans to invest $1.46 billion in Rio Grande do Norte state—along with Ceará, part of the Potiguar basin—for E&P, gas, energy, distribution, safety, and environmental activities. In E&P alone $1.1 billion will be invested in several fields, with emphasis on the expansion of Ubuaram field, which clocked 30 years of production in 2006, and the development of Dentão field and other projects, said Petrobras.

The first two wells in Manati field in the Camamu-Almada basin in South Bahia are producing a total of 1.8 million cu m/day of gas for Petrobras and partners Queiroz Galvão and Rio das Contas of the Norse Energy Norwegian group. Operations are expected to begin this year. The PMT-1 fixed platform is being installed, along with 125 km of pipelines, and a gas treatment plant is in the final stage of construction in the municipality of São Francisco do Conde.

In Camamu-Almada, 11 blocks are under exploration, operated by consortiums of companies such as Queiroz Galvão, Statoil ASA, Devon Energy Corp., Eni SPA, and El Paso Corp.—unusual in that other basins generally are dominated by Petrobras. El Paso has reported six gas and oil finds on its concession Block BMCAL-4. The other blocks are still in the exploration phase, with deadlines of 2008-14, according to National Petroleum and Biofuels data.

Brazil's largest circulation daily, O Globo, reported that Chevron Brazil will invest $3 billion in several areas in Brazil during the next few years and will start production of 110,000 b/d of oil by 2015 from Frade field, in the Campos basin.

Also in the Campos basin, Devon Energy operates Polvo field in 105 m of water. It is expected to produce 50,000 b/d of oil starting next year, Devon said. Devon has invested $400 million in Brazil.

Royal Dutch Shell PLC has invested $1.5 billion. Shell was the first multinational oil company to produce crude in Brazil after Petrobras lost its upstream monopoly in 1998. The discovery in the Campos basin's Bijupirá-Salema fields produces 40,000 b/d of oil. Shell is working in its two most important production projects: Block BC-10 in the Campos basin and Block BS-4 in the Santos basin, which has been declared commercial (OGJ Online, Jan. 4, 2007).

Norsk Hydro ASA also has invested $400 million and expects to produce 100,000 b/d of oil in the Campos basin by 2010. ✦

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Central Wilmington oil field due for denser development

The central part of supergiant Wilmington oil and gas field is in the midst of a redevelopment project in which more than 500 wells drilled in the next few years.

Los Angeles city authorities in late 2006 approved the drilling of as many as 540 directional oil and water injection wells from central facilities. The zoning approval facilitates plans by Warren Resources Inc., New York, to drill from two cellars under construction and due to be in operation by the end of the first quarter of 2007.

Warren Resources had booked 50 million bbl of net proved reserves in Wilmington at the end of 2005 and believes its two units in the central part of the field hold large oil recovery potential.

The Wilmington Townlot Unit, the company estimates, has produced only 20% of the estimated 727 million bbl of original oil in place, leaving an average remaining recovery potential of 228,000 bbl/well. The adjacent North Wilmington Unit has produced 24% of the estimated 165 million bbl of OOIP compared with 36% recovery for the field.

In fact, Warren Resources estimates that Townlot could yield another 92 million bbl of oil if the company were able to attain a 32% recovery factor.

Greater Wilmington field, the majority of which is operated by Occidental Petroleum Corp., had produced more than 1 billion bbl of oil and 900 bcf of gas through the late 1960s since discovery in 1932. Cumulative oil production has now surpassed 2.5 billion bbl. Part of the field underlies Long Beach harbor (OGJ, Aug. 15, 2005, p. 18). An Exxon Corp. predecessor unitized Townlot in 1973, and the former Sun Oil Co. unitized North Wilmington the same year.

Warren's tenure

Warren Resources took over operation of Townlot in March 2005 and North Wilmington at the end of 2005.

The units are in the Los Angeles basin north of the city of Long Beach.

The company had hiked Townlot production to more than 2,000 b/d in late January 2007 from 375 b/d at acquisition and said it is beginning to see the effects of its waterflood in the Upper Terminal formation. North Wilmington, where the 2006 program was to return idle wells to production, makes close to 400 b/d.

The 2007 budget is $50 million at Townlot and $18 million at North Wilmington for drilling and infrastructure. That includes 34 producing and injection wells at Townlot and 14 new wells and 12 recompletions at North Wilmington.

The units produce oil mainly from the Upper Terminal at 4,000 ft and the shallower Ranger and Tar formations, all Tertiary in age. The deeper Ford zone has produced 4.1% of 70 million bbl of OOIP at Townlot.

The strategy at Townlot is to develop seven-spot waterflood patterns in the Ranger and Upper Terminal formations. Meanwhile, the first six Tar formation wells were averaging 125 b/d of oil with a water:oil ratio of 1 in late January 2007, albeit on limited production history. The former operator did

CENTRAL WILMINGTON FIELD UNITS

Fig. 1

Source: Warren Resources Inc.

not waterflood the Tar zone.

The company plans to construct as many as five doublewide drilling cellars at Townlot that can each accommodate two rows of wells in open cement-lined trenches. This permits production equipment to be located below ground level.

A skid-mounted drilling rig allows for rapid rig moves, and all fluid production and clean water reinjection occurs at wellheads in the cellars. ✦

Conasauga shale gas play grows in Alabama Valley and Ridge

A gas shale play is taking off in northern Alabama on the east side of the Valley and Ridge Province.

The Alabama Oil & Gas Board set a hearing for Feb. 16 in Ashville, Ala., on an application by Dominion Black Warrior Basin Inc. to establish field rules and 320-acre well spacing for a 40-sq-mile area in northern St. Clair County.

The field, proposed to be named Big Canoe Creek, is underlain by a Cambrian Conasauga shale gas pool logged as productive between 1,946 ft and 6,944 ft in Dominion's Newman well in SW NE 27-13s-4e, St. Clair County. Dominion spud the well on Apr. 6, 2006, and drilled to TD 7,039 ft.

The upper and lower productive limits of the Conasauga shale gas pool in the proposed field have yet to be fully defined, Dominion's application said.

The area: 24, 25, and 36-13s-3e; 19 through 36-13s-4e; 19, 20, and 29 through 32-13s-5e; 1 and 12-14s-3e; and 1 through 11-14s-4e.

Overall, operators have taken several hundred thousand acres aimed at exploring shale plays in the Valley and Ridge and in the Black Warrior basin to the west. Leasing is reported in Etowah and Cherokee counties, Alabama, and at least as far northeast as Chattooga County, Georgia.

Dominion has drilled at least eight wells in the general area in the past year or more.

The company also asked that "production allowables be established and that production royalties be escrowed pending further orders of the board, after notice to establish the ultimate production unit."

Parent company Dominion, Richmond, Va., in November 2006 announced plans to divest most of its oil and gas assets by mid-2007 to concentrate on its electricity generation and utility businesses (OGJ Online, Nov. 1, 2006).

Dominion E&P claims 6.6 tcf of proved gas reserves, of which it would retain 1.1 tcf of low-risk properties in the Appalachian basin. ✦

Eastern France CBM well encouraging

European Gas Ltd., Perth, is drilling a second well after reporting "highly encouraging results" from its first coalbed methane stratigraphic well on the St. Avold portion of the Bleue Lorraine Permit in northeastern France.

Meanwhile, European Gas was awarded Bleue Lorraine Sud, a 528 sq km permit contiguous to the south, for five years, said Gilbert Clark, European Gas manager for France. He said, "The acreage covers the same coal sequences as Bleue Lorraine."

The Folschviller-1 directional well went to TD 1,306 m and cored the Westphalian D coal-bearing sequence from 705 m to TD. The well encountered 60 m of coal in four seams each more than 10 m thick.

The company reported gas content of 9.5 cu m/ton and permeability of up to 2.8 md, higher than expected. The coal is likely to be able to sustain gas flow at this drillsite, it said.

The well is just east of the town and coal mine named Folschviller. The mine, in operation 30 years and considered exceptionally gassy, was closed in 1979. European Gas spud the second well, at Diebling on the Alsting portion of the permit 20 km northeast of Folschviller-1, in November 2006. The first well confirmed that the Westphalian D coals are mostly analogous to and thicker than the Hartshorne coals in the Arkoma basin in eastern Oklahoma.

The 460 sq km Bleue Lorraine Permit is near the border with Germany and 55 km southeast of the border with Luxembourg. European Gas is drilling on a farmout from Heritage Petroleum PLC, London. In late 2005, the companies estimated gas in place on 15% of Bleue Lorraine at 992 bcf. ✦

Bangladesh

Sangu field, initially estimated at 800 bcf recoverable, has produced more than 400 bcf since going on production in 1998, said Cairn Energy PLC, London, and its Capricorn Energy Ltd. affiliate.

Production has fallen to about 115 MMcfd in December 2006, and Cairn has begun a three-well drilling program. The first well will appraise Sangu South field 4 km southeast of the main field. The second targets a possibly undrained part of Sangu field. The third, Hatia-1, is a vertical exploration well on a potentially large prospect 10 km northwest of Sangu.

Remedial work has begun on some of Sangu's producing wells in the Bay of Bengal off Chittagong.

Cairn reduced Sangu's gross booked reserves by 187 bcf to 142 bcf due to several factors.

EXPLORATION & DEVELOPMENT

Colombia

Emerald Energy PLC, London, was awarded the Helen exploration and production contract area covering 213 sq km in the Putumayo basin.

Subject to government approval, Vetra Energy Group LLC will fund 100% of the initial exploration phase in return for operatorship and an 85% interest.

First phase of the exploration period is up to 16 months, and minimum work program is to shoot 30 km of 2D seismic surveys and reprocess 120 km. A second phase, if entered, requires drilling one well to 10,000 ft.

Georgia Republic

CanArgo Energy Corp. spudded the Kumisi-1 appraisal well projected to 12,140 ft just south of Tbilisi on the Nazvrevi/Block XIII production sharing contract area in the Kura basin of Georgia Republic.

The well is to appraise the Soviet-era West Rustavi-16 Cretaceous gas-condensate discovery. Seismic surveys shot by CanArgo indicate that a large structure may be present. The reservoir performed well on tests.

The drillsite is near the route of the new South Caucasus gas trunkline, and the government has committed to purchase any gas discovered at Kumisi.

Kazakhstan

Lukoil Overseas Holding Ltd. took a farmout from TOO Zhambai, contractor under the PSA on the Zhambai South and South Zaburuniye blocks in shallow water and the transition zone of the Kazakh Caspian Sea.

Lukoil Overseas took a 25% interest in late 2006 in the blocks, which total 2,000 sq km. An earlier 2D seismic survey led to identification of the Edil, Kosarna, and Karabulak prospects.

Lukoil Overseas said it will implement the exploration project jointly with state KazMunaiGas and Repsol Exploracion Kazakhstan, Madrid.

Namibia

Tower Resources PLC, London, is preparing to shoot a 2D seismic survey later in 2007 over a large structure on its acreage in the Atlantic off northern Namibia.

The company holds blocks 1910, 1911a, and 2011a along the southern flank of the Walvis Ridge.

An organic geochemistry study confirmed that three of four potential source rocks are likely to be mature with large areas at peak maturity, the company said. A sea surface oil seep study indicated the possible presence of natural liquid hydrocarbon slicks at surface south and east of the Dolphin graben, the deepest sedimentary sequence on the licenses.

AVO analysis of six selected seismic lines highlighted the potential for commercial gas reserves in the northern part of the licenses, mainly in a large structure west of but adjacent to the deepest kitchen area of the Dolphin graben.

Nova Scotia

PetroWorth Resources Inc., Calgary, retained consulting geoscientists to evaluate the geological and geophysical components of the petroleum systems on the Ainslie Block in southwestern Cape Breton Island, NS.

PetroWorth has 100% exploration and development rights to 383,000 acres on the block.

The same consultants found in a 2004 study that the block's geology is similar to that of McCully gas field and Stoney Creek oil and gas field in New Brunswick. The new work will include collection of 200 soil gas samples from depths of 1.4 to 1.6 m, which will assist in the design of a seismic program.

Numerous oil seeps have been observed along the western shore of Lake Ainslie, and the widespread distribution of the Strathlorne formation on the block is of particular interest to oil and gas explorers because of its similarity to the commercially productive Albert formation (Mississippian Horton Group) in New Brunswick, PetroWorth said (OGJ Online, Apr. 19, 2005).

South Dakota

Spyglass Cedar Creek LP, private San Antonio independent, found gas in Cretaceous Shannon sand at two wells on the South Cedar Creek project in Harding County, said participant Gold Point Energy Corp., Vancouver, BC.

The Shannon sand pay zone found in the Spyglass State 4-35 well in 35-18n-4e and State 3-30 wells four miles apart is similar to that found at West Short Pine Hills field 12 miles to the west. State figures show that field has produced 23 bcf of gas, Gold Point said.

Spyglass is operator of the 63,500-acre project, on which a proprietary seismic method is being used that has identified numerous Shannon development locations. More seismic surveys are being acquired.

Texas

North

Morgan Creek Energy Corp., Dallas, plans to explore for gas in Mississippian Barnett shale in McLennan County, Tex.

The Boggs-1, in Morris Moore Survey, is projected to 8,500 ft. The location is on a 40-acre unit less than 1,500 ft from a gas pipeline.

Utah

The 2007 program calls for drilling 280 wells using eight operated and four to six nonoperated rigs in Greater Natural Buttes gas field in the Uinta basin, said Anadarko Petroleum Corp.

Net production climbed 33% in 2006, averaging 206 MMcfd in the quarter ended Dec. 31 and peaking at 216 MMcfd during the quarter.

Anadarko drilled three 20-acre pilot infill wells in the quarter to evaluate recovery potential in the more developed areas of the field, now on 40-acre spacing.

Approach diagnoses, reduces water cut

Mahmoud Abu El Ela
Cairo University, Giza, Egypt

Ismaiel Mahgoub
Khaled Mahmoud
Khalda Petroleum Co. Cairo

Oil field operators have employed numerous treatment methods, both mechanical and chemical, to reduce water production rates. But central to determining the treatment method is a cost-effective plan for diagnosing and solving the excess water production problem.

Water cuts in producing wells typically increase as oil fields mature with estimated water disposal cost of about $40 billion worldwide.

Treatments in two oil wells in Egypt operated by Khalda Petroleum Co., an international joint-venture company, illustrate successful jobs for reducing excess water cut.

Water production

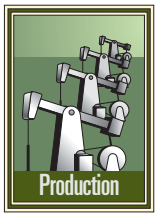
Worldwide oil production is about 75 million b/d with water production estimates varying between 300-400 million b/d. The ratio of 4-5 bbl of water/1 bbl of oil produced is a conservative estimate.[1]

High water production increases both lifting and water disposal costs, while it reduces oil production. It also causes additional maintenance for production equipment and requires downhole treating for corrosion, bacteria, scale, and naturally occurring radioactive material (NORM).

Water-treatment costs are in the range of $0.75-2/bbl onshore and $1-3/bbl offshore.[2]

A cost-effective plan for water problem diagnosis incorporates the following steps (Fig. 1):

- Recognizing immediate problem.
- Identifying water source.
- Assessing problem.
- Preparing optional and contingency solutions.
- Evaluating all options.
- Selecting best placement technique.
- Implementing plan.
- Evaluating and analyzing results.
- Reacting as necessary to the results.



Recognizing the problem

Oil field operators need to recognize that there are two distinct types of water production.

The first type, usually occurring later in the life of a waterflood, is water co-produced with oil because of the fractional flow characteristics in reservoir porous rock. A reduction of this water production correspondingly would lead to reduced oil production.

The second type of water production directly competes with oil production. This water usually flows into the wellbore through a different path than the oil, such as from water coning, cross flow, or high-permeability water channels. In these cases, reducing water production often can lead to greater pressure drawdowns with subsequent increases in oil producing rates. Water shutoff treatments should target this second type of water production.

Three common indications of a water problem are: [3,4]

1. Some wells exhibiting a sudden increase in water cut.
2. A well or pattern of wells may start producing at a much higher water/oil ratio than similar patterns.
3. Plots of fluid production vs. time

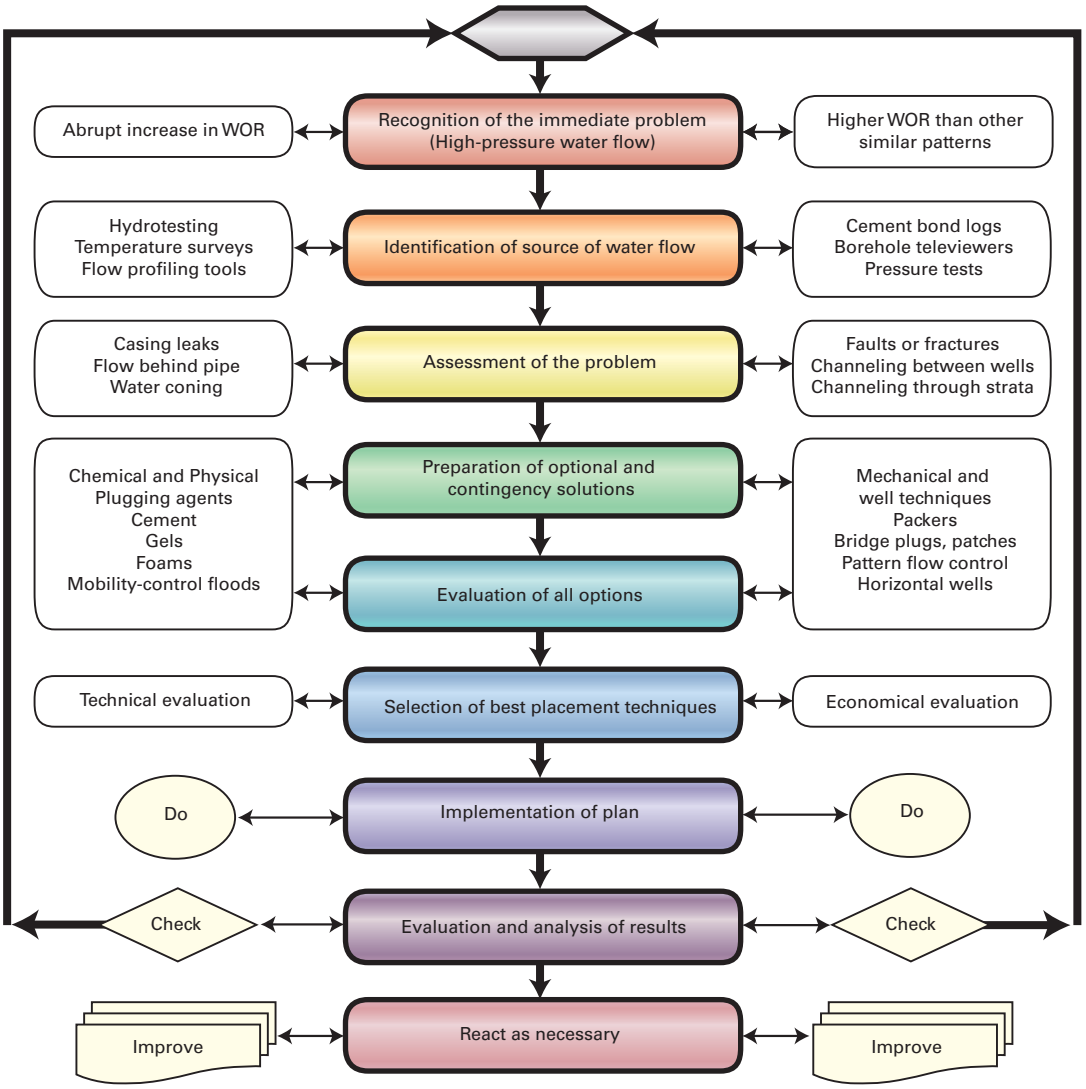
EXCESS WATER PROBLEMS, TREATMENT

Table 1

Category	Problem	Treatment
A	1. Casing leaks without flow restrictions. 2. Flow behind pipe without flow restrictions. 3. Unfractured wells (injectors or producers) with effective barriers to cross flow.	Conventional treatments normally are effective.
B	4. Casing leaks with flow restrictions. 5. Flow behind pipe with flow restrictions. 6. Two-dimensional coning through a hydraulic fracture from an aquifer. 7. Natural fracture system leading to an aquifer.	Treatments with gelants normally are effective.
C	8. Faults or fractures crossing a deviated or horizontal well. 9. Single fracture, causing channeling between wells. 10. Natural fracture system, allowing channeling between wells.	Treatments with preformed gels are effective.
D	11. Three-dimensional coning. 12. Cusping. 13. Channeling through strata (no fractures), with cross flow.	Difficult problems where gel treatments should not be used.

PLAN FOR DIAGNOSING, SOLVING EXCESS WATER PROBLEMS

Fig. 1



may show an abrupt increase in the water/oil ratio.

Identifying water source

Table 1 lists water production problems and treatment catagories.[5] Each problem requires a different approach for an optimal solution. Achieving a high success rate when treating water production problems requires first correctly identifying the nature of the problem.[6]

Identifying the nature and source of water production problems should begin with information already at hand. Some common methods used to diagnose these problems include:

- Leak tests and casing integrity tests, such as hydrotesting.
- Temperature surveys.
- Flow profiling tools, such as radio-tracer flow logs, spinner surveys, and production logging tools.
- Cement bond logs.
- Borehole televiewers.
- Noise logs.

Many of these methods are used during routine surveillance of wells.

Several methods assess whether cross flow exists between strata, including pressure tests between zones; various logs for determining fluid saturations, permeability, porosity, and lithology; injection-production profiles; simulation; and seismic methods. If the operator does not know whether cross flow occurs, he should assume that cross flow exists.[5]

Logging is important for identifying water zones not only before drilling, but also after production has matured. Open and cased-hole logs can determine fluid saturations, identify water zones and water entry points, measure flow rates, and evaluate cement bond, downhole tubulars, and casing.

Avoiding water-handling costs is one way for operators to justify logging costs.

Water problem assessment

Table 1 lists the various water problems, prioritized and categorized from least

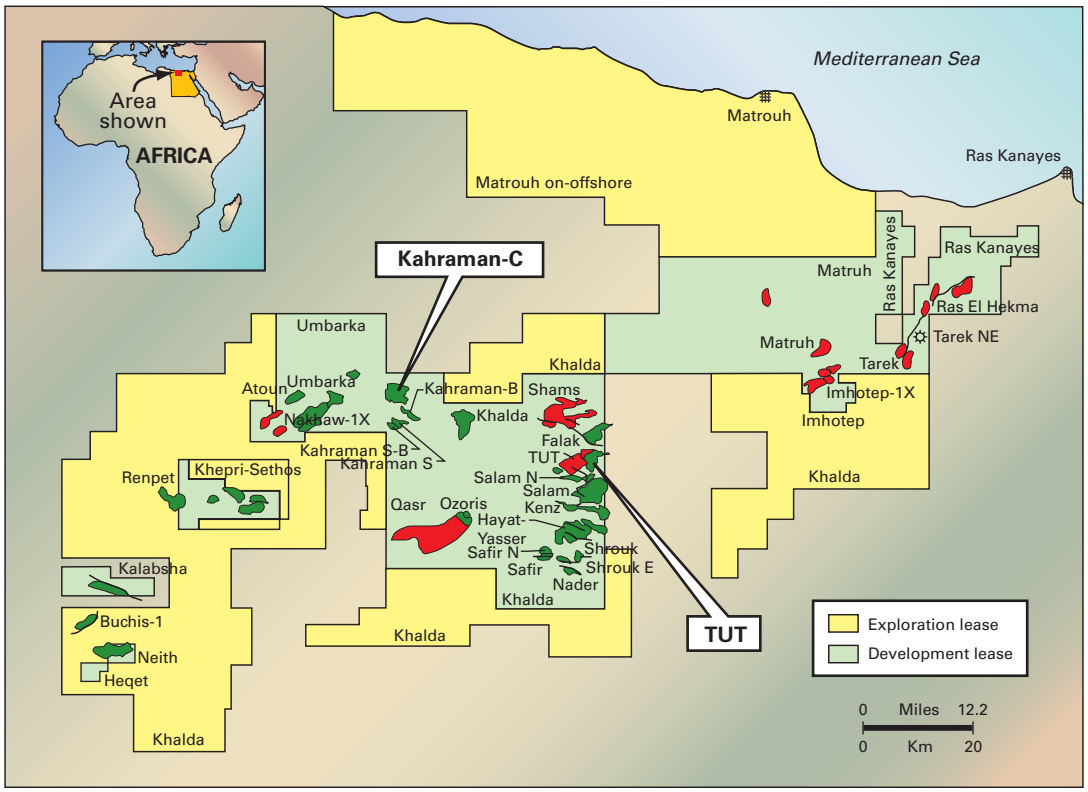
WATER SHUTOFF MATERIALS, METHODS

Table 2

Chemical, physical plugging agents	Mechanical and well techniques
Cement, sand, calcium carbonate	Packers, bridge plugs, patches
Gels, resins	Well abandonment, infill drilling
Foams, emulsions, particulates, precipitates, microorganisms	Pattern flow control
Polymer and mobility-control floods	Horizontal wells

KHALDA CONCESSION

Fig. 2



to most difficult. The list is based on extensive reservoir and completion engineering studies and analyses of many fields,

The first three problem types in Table 1 (Category A, Problems 1-3) generally are easier to treat than the others in the list. Therefore, one should look first for these types of problems.

In contrast, the last three problems (Category D, Problems 11-13) are difficult with no easy, low-cost solution. Gel treatments will almost never work for these problems.

The intermediate problems (Categories B and C, Problems 4-10) result from linear-flow features such as fractures, fracture-like structures, narrow channels behind pipe, or vug pathways.

Solutions

Proper perforation techniques, chemically or mechanically closing down high-permeability streaks, or separating the water from the oil downhole can solve excess water production problems.[2] These methods generally can be categorized as chemical or mechanical (Table 2). Each method may work well for certain problems but may be ineffective in other cases.

Conventional methods, such as cement and mechanical devices, normally should be the first applied for treating the easiest problems. These problems include casing leaks and flow behind pipe where cement can be placed effectively and in unfractured wells where impermeable barriers separate water and hydrocarbon zones.

Gelant treatments normally are the best option for casing leaks and flow behind pipe with flow restrictions that prevent effective cement placement. Both gelants and preformed gels have successfully treated hydraulic or natural fractures that connect to an aquifer.

Treatments with preformed gels normally are the best option for faults or fractures crossing a deviated or horizontal well, for a single fracture causing channeling between wells, or for a natural fracture system that allows channeling between wells.

Gel treatments can be categorized into three main types: permeability blockers, selective permeability blockers, and relative permeability modifiers.

Options

When the water-producing zone is known, operators can use mechanical gravel-packed slotted liners selectively to produce certain zones. When the water-producing zone is unknown or when there are breakthrough or operating difficulties, they can use chemical methods such as gels, catalyzed silicate injection, or micromatrix cement. Chemical methods may need repeating as the production profile changes or the chemicals break down with time.

Selecting the optimum method should depend on the technical and economical evaluation of previous fields' applications.

After implementing the treatment method, the operator needs to monitor the water/oil ratio regularly to determine success of the method.

Kahraman-C41

A well in Kahraman-C field provides an example of a successful treatment for reducing water production.

The field is in the northwest part of the Khalda concession in the north part of Egypt's western desert (Fig. 2). The field discovery well, Kahraman-C2, was drilled in 1992. The field currently has 60 oil producing wells and 18 water-injection wells.

Kahraman-C mainly produces from

Bahariya reservoirs that consist of laminated sandstone divided into two main horizons: Lower Bahariya (LBAH) and Upper Bahariya (UBAH). The Lower Bahariya is the main producing interval, providing about 70% of the field's total production. The interval has good quality sand with a permeability up to 400 md and porosity of up to 24%.

The Upper Bahariya has lower quality rock consisting of thin sand streaks interbedded with shale and carbonate barriers. The operator is currently developing the zone with hydraulic fracturing, not only in Kahraman-C field but also in most other fields in the Khalda concession.

The Bahariya reservoirs lie at about –5,700 ft subsea.

Well Kahraman-C41 was drilled in February 2005 as part of the integrated plan for developing both the upper and lower Bahariya to the west of Kahraman-C field. The petrophysical analysis revealed 41 ft of good quality pay with an average 23% porosity and average 40% water saturation.

The LBAH in the well was as good as the LBAH that produces in the west area of Kahraman-C field. A repeat formation tester (RFT) was not recorded in this well, however, at almost the same drilling time, an RFT was run in the offset Kahraman-C46 well, which is 560-m away.

The Kahraman-C46 RFT showed pressures of 970 psi in the main producing sand, 1,500 psi in the wet sand right below the main producing sand, and 2,600 psi in the wet sand further downhole.

The initial LBAH intervals perforated in Kahraman-C41 were at 6,540-6,554 and 6,566-6,590. The test of the intervals with nitrogen lift produced all water at 960 b/d. The water had a 78,500-ppm chloride content, which is the same as in Bahariya water.

Review of the cement-bond log-variable density (CBL-VDL) log showed bad cement behind the casing with almost free pipe. This indicated that cross flow from the high-pressure wet sand into the low-pressure oil zone through the channels behind the casing may be causing the water problem.

To remedy the problem, the operator performed a cement squeeze with 17.5 bbl of cement through the perforated intervals. After drilling out the cement and cleaning the hole, the operator perforated the LBAH intervals 6,540-6,554 and 6,566-6,580.

The test of the well with nitrogen lift again produced 100% water at 222 b/d. The water contained 79,900 ppm chlorides.

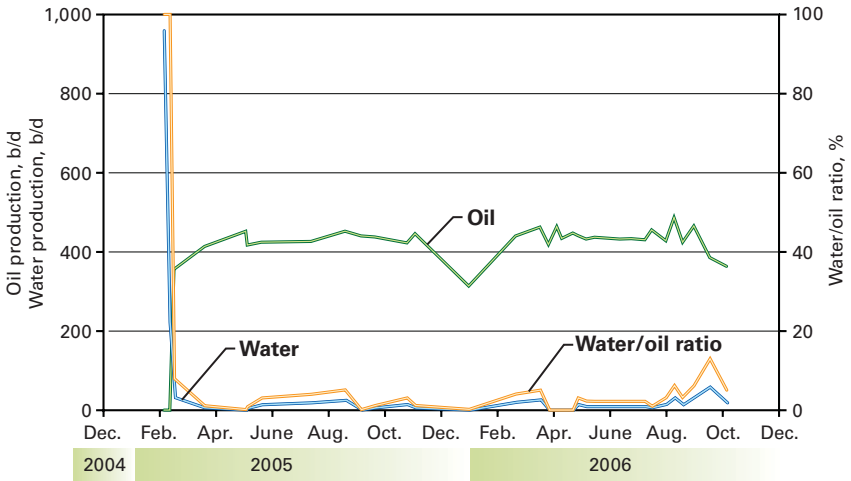
A new CBL-VDL showed some cement improvement against the LBAH compared to the original CBL-VDL that showed almost free pipe.

The offset well in the same reservoir, 560-m away, produced oil with a low water cut, about 5%.

Based on this information, the conclusion was that water had cross flowed from the high-pressure wet sand to the low-pressure oil zone through the channels behind the casing after the initial perforation of the LBAH and during the first test. During that period, water had moved from the wet sand into the oil zone because of the high-pressure difference. This resulted in the 100% water cut during the second test after the cement squeeze job.

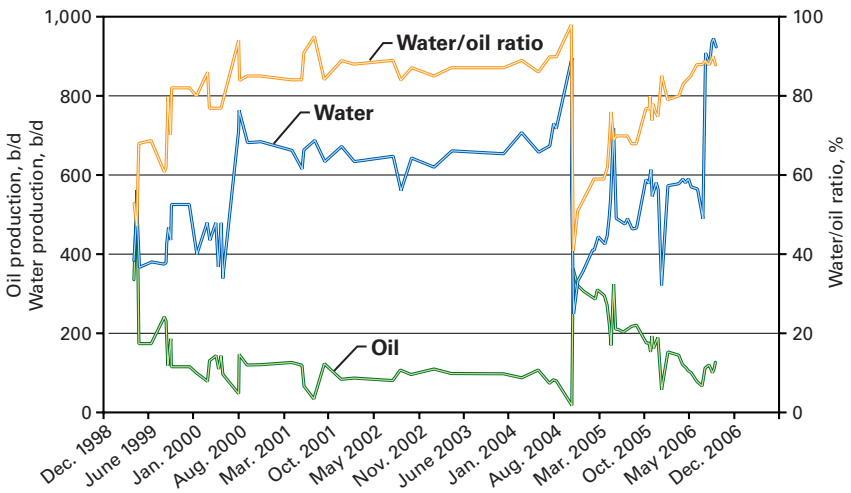
Well Kahraman-C41

Fig. 3



Well TUT-33

Fig. 4



The cement squeeze job appeared successful, as indicated by the drop in production between the two tests, 950 b/d in the first and 222 b/d in the second.

The operator decided to complete the well and run an electric submersible pump (FC-450) that could handle up to 500 b/d and remove the water that had crossed flow into the oil zone. This proved to be the right decision because a test 6 days later produced 385 b/d of fluid with a 8% water cut or 354 bo/d.

The well to October 2006 had produced a cumulative 260,000 bbl of oil, and the production rate in October was still 380 b/d of fluid with a 5% water cut or 360 bo/d (Fig. 3).

TUT-33

Another example of a successful water shut off treatment is from TUT field, in the Khalda Ridge concession on the border separating the Khalda and Agiba concessions (Fig. 2).

Well TUT-01 discovered the field in 1986. It currently has 21 oil producing wells and 3 water-injection wells. Production is from the AEB, Kharita, and Bahariya formations. TUT field is one of the largest in the Khalda concession, having produced about 15% of the total oil from the area.

The Kharita formation is a very high quality stratified sandstone with a permeability of up to 1,000 md. The formation normally has multiple zones, each having its own aquifer. The reservoirs produce under an active water drive. In TUT field, the Kharita lies at about –6,300 ft subsea.

Well TUT-33, drilled in April 1999, targeted the Kharita and AEB reservoirs. The petrophysical analysis revealed 16 ft of good quality pay in Kharita Zone II that has a 19% porosity, and 12% water saturation, and 19 ft of better quality pay in Kharita Zone I that has 28% porosity, and 13% water saturation.

The well, completed through the two zones commingled, produced with an ESP at an initial rate of 2,136 b/d of fluid with a 53% water cut or 1,004 bo/d (Fig. 4).

In July 2000, the water cut reached 80% (Fig. 4). The operator, therefore, decided to work over the well to identify the water source. The belief was that Zone II was the source. Thus it was tested separately after isolating Zone I between two packers. Zone II tested 2,370 b/d of fluid with a 93% water cut or 166 bo/d.

Because of the considerable oil rate, the operator decided to keep producing from both zones commingled.

In mid November 2004, water cut reached 90% (Fig. 4); thus the operator again decided to test Zone II separately. The test produced 2,738 b/d of fluid with a 98% water cut or 55 bo/d. After isolating Zone II with a bridge plug, the operated tested Zone I on Nov. 17, 2004. That zone produced 1,846 b/d of fluid with a 93% water cut or 130 bo/d.

These tests indicated that the high-pressure difference may be causing cross flow from Zone II into Zone I. The operator, therefore, completed only Zone I with Zone II being isolated mechanically with a bridge plug.

Production during the next few days confirmed the cross flow. Five days after the completion work, the well tested at 1,835 b/d of fluid with a 41% water cut or 1,083 bo/d. The water cut continued to drop to 41% from 93% (Fig. 4).

The next tests continued to confirm the cross flow. On Dec. 12, 2004, the well tested at 1,962 b/d fluid with a 51% water cut or 961 bo/d. The well after about 2 years of production produces with 90% water cut, which is less than on the first test.

The well during 2 years has produced a cumulative 400,000 bbl of oil. ✦

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Biodiesel tax credits present significant financial incentives if handled properly

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US tax credits for biodiesel mixtures can provide significant tax advantages for producers that understand and properly follow the regulations, which continue to be in effect through Dec. 31, 2008.[1] US refiners should understand these benefits if and when they blend biodiesel into final fuel products.

Currently, an income tax credit of $1/gal for agricultural biodiesel (agri-biodiesel) and 50¢/gal of biodiesel is available to producers of biodiesel mixtures.

The American Jobs Creation Act signed by Pres. George W. Bush in 2004 established a federal tax credit for production of biodiesel fuel and biodiesel fuel mixtures produced after Dec. 31, 2004. According to the Internal Revenue Code, producers of biodiesel mixtures are able to receive a payment from the US Treasury for any biodiesel credits earned in excess of the excise tax attributable to the biodiesel mixture set forth on a quarterly return.

Biodiesel is a diesel-equivalent, processed fuel derived from biological sources, divided into two categories by the Internal Revenue Code: biodiesel and agri-biodiesel. Agri-biodiesel is distinguished from biodiesel in the code and refers to a special type of biodiesel derived solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, other plant matter, and animal fats.

The use of agri-biodiesel in biodiesel fuel mixtures yields a $1/gal tax credit compared with a 50¢/gal credit for regular biodiesel.

Biodiesel mixture credit

A producer of a biodiesel mixture can make a claim for the biodiesel used to make the mixture itself.[1] To receive the credit, the producer must make a "qualified biodiesel mixture," which is a mixture of biodiesel and diesel fuel determined without regard to any use of kerosine.[1]

The producer may only claim the credit if it sells or uses this mixture it has produced.[1] The credit applies to each gallon of biodiesel used to produce the mixture, but only if the mixture is sold by the blender for use as a fuel or is used in the producer's trade or business.[1]

Example: If a refiner uses 1,000 gal of biodiesel to produce 5,000 gal of a qualified biodiesel fuel mixture, that refiner will be entitled to a biodiesel mixture credit of $500 (1,000 gal x 50¢/gal). If the refiner had used agri-biodiesel, the credit would be $1,000 (1,000 gal x $1/gal).

The taxpayer may claim the biodiesel mixture credit on a quarterly basis and produce a Certificate for Biodiesel in order to make a claim.

Section 6426 allows a credit against the excise tax imposed on taxable fuel for blenders of biodiesel that qualify for the biodiesel mixture credit. To the extent that the taxpayer's biodiesel mixture credit exceeds that taxpayer's excise tax liability for any particular quarter, the blender may request an income tax credit or a payment from the IRS.[1]

Each request must include:

- The amount of agri-biodiesel and biodiesel in the biodiesel mixture.
- A copy of a Certificate for Biodiesel.
- A statement by the claimant that it has no reason to believe information contained in the certificate is false.

The IRS also requires that any producer of a taxable fuel mixture containing biodiesel must register as such with the IRS to claim the biodiesel mixture credit. Additionally, producers of biodiesel mixtures can receive a

payment from the US Treasury for any biodiesel credits earned in excess of the excise tax attributable to the biodiesel mixture set forth on a quarterly return.

One must only register as a blender if the taxpayer's mixture produces a taxable fuel. If a taxable fuel is not produced, then no blender registration is required.

To claim the biodiesel mixture credit, and any corresponding payments for credits that exceed excise tax liability, the producer of the mixture must obtain a Certificate for Biodiesel from the biodiesel producer. The certificate must identify the product produced and percentage of biodiesel and agri-biodiesel in the product.[2]

The biodiesel mixture credits and excise tax operate independently of each other. This means that a blender of biodiesel fuel can take advantage of the biodiesel credit even if it has not paid any excise taxes for taxable fuel.

If a refiner, for example, mixed and sold a blended biodiesel mixture that contained less than 4% normal paraffins (an excluded liquid), it would not have to pay excise tax on the biodiesel used to create that liquid. The refiner would, nevertheless, be able to claim the biodiesel mixture credit for any biodiesel used in the mixture.

'Taxable fuel'

The excise tax on taxable fuel may apply to the biodiesel contained in the biodiesel mixture.

Pure biodiesel, because it contains more than 4% normal paraffins, is not considered a taxable fuel. Section 4081(a)(1) imposes a tax on certain removals and sales of taxable fuels. Section 4083 defines taxable fuel as diesel fuel, gasoline, and kerosine. Treasury Regulations define diesel fuel as any liquid that, without further processing or blending, is suitable for use as a fuel in a diesel-powered highway vehicle or train.[3]

The definition of diesel fuel does not, however, include "excluded liquid."[3] The definition of excluded liquid includes any liquid that contains less than 4% normal paraffins.[3] Mentioned previously, although biodiesel is suitable for use as a fuel in a diesel-powered highway vehicle, it contains less than 4% normal paraffins and is therefore an excluded liquid and not subject to excise tax.

If biodiesel, however, is used in the production of blended taxable fuel, a tax is imposed on the removal or sale of the blended taxable fuel containing the biodiesel.[4] The tax is computed on the difference between the total number of gallons of blended taxable fuel and the number of gallons of previously taxed taxable fuel used to produce that blended taxable fuel.[3]

If 800 gal, for example, of taxable diesel fuel is added to 200 gal of previously untaxed biodiesel to create 1,000 gal of B20 biodiesel fuel, an excise tax will be imposed on the 200 gal of biodiesel used to create the mixture. The biodiesel used in the mixture is taxable because B20 biodiesel fuel exceeds the 4% normal paraffins base and, therefore, is not an excluded liquid, but a taxable fuel.

A discussion of when the excise tax rate is applied (i.e., at what stage of the process) is beyond the scope of this article.

The IRS has published no guide for when a biodiesel mixture ceases to be an excluded liquid because it contains less than 4% normal paraffins. The test for the amount of normal paraffins contained in the liquid was originally meant to apply to mineral spirits, not biodiesel, but has nevertheless been applied to biodiesel.[4]

B20 is considered a blended taxable fuel and does contain more than 4% normal paraffins.[5] The IRS, however, has published no guide for what concentration of biodiesel to diesel fuel will cause a liquid to become a blended taxable fuel.

The IRS has recently released guidance regarding the biodiesel mixture credit as to what constitutes a qualified biodiesel mixture. Notice 2005-62 notes that the mixture must contain at least 0.1 vol % of diesel fuel. This means, for example, that a mixture of 999 gal of biodiesel and 1 gal of diesel fuel would qualify for the credit.

The biodiesel mixture credit is an opportunity for biodiesel blenders and refiners to reduce the excise taxes imposed on the fuel and possibly receive a payment from the IRS in the event the credit exceeds any excise taxes.

While financial incentives can be significant, biodiesel producers need to consult with their tax and legal advisors to ensure proper application of the regulations and requirements. ✦

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2007 construction lags 2006, but more projects lie ahead

Christopher E. Smith
Pipeline Editor

Planned pipeline construction to be completed in 2007 slipped nearly 13% from the previous year, driven by the 2006 completion of large crude pipelines. Plans for 2007 construction of both natural gas and products pipelines expanded, however, despite the year-on-year decline in the total number of miles set for completion.

Operators plan to complete installation of more than 10,000 miles in 2007 alone (Table 1), with natural gas construction making up 71% (nearly 7,200 miles) of the plans, based on reports from the world's pipeline operating companies and data collected by Oil & Gas Journal.

Looking forward, to 2007 and beyond, greater mileage is planned in all three pipeline categories (crude, natural gas, and products) than had been the case last year, with the US passing the Asia-Pacific as the region with the most construction planned.

US natural gas prices remained sufficiently strong to keep large infrastructure projects such as pipelines moving forward in 2007, particularly when coupled with expectations of continued growth in demand. A surge in natural gas pipeline activity is also likely this year in Asia-Pacific, driven by a combination of Chinese demand and Central Asian, Russian, and Southeast Asian supplies.

By contrast, natural gas pipeline plans in the Middle East, Latin America, and Africa tailed off, with a good deal of work completed in 2006 and therefore no longer on the books.

Plans for construction of product pipelines in 2007 grew in the US and Europe, with natural gas liquids transportation keying US growth while olefins lines led the way in Europe.

As 2007 began, operators had announced plans to build nearly 67,000 miles of crude oil, product, and natural gas pipelines beginning this year and extending into the next decade (Fig. 1), a substantial increase over data reported last year (OGJ, Feb. 13, 2006, p. 57) in this report.

The vast majority (more than 70%) of these plans is for natural gas pipelines, but this was down somewhat from the previous year, with the difference split roughly evenly between crude and product plans.

Outlook

The continued up-tick in worldwide pipeline construction trends follows US Energy Information Administration energy consumption forecasts, which also show continued growth.

EIA forecast world marketed energy consumption to increase by 71% through 2030 (using a 2003 baseline), a period that encompasses the long-term pipeline construction projections stated here.

Energy demand growth will be strongest, according to the midyear 2006 analysis, among emerging economies, with the most rapid growth seen in non-OECD Asia (which includes India and China), where demand will nearly triple over the projection period.

Fuelling this energy demand growth is a projected gross domestic product growth in non-OECD Asia of 5.5%/

year through 2030—led by China at 6%/year, the highest projected growth rate in the world—compared with 3% worldwide.

Structural issues that have implications for medium to long-term growth in China include the pace of reform affecting inefficient state-owned companies and a banking system that is carrying a large number of nonperforming loans, according to EIA.

Last month, EIA reduced projected US energy consumption in 2030 to 131.2 quadrillion btu, 2.7 quadrillion btu lower than the previous year's projection. Even with this 2% drop, however, energy consumption will still increase more rapidly than energy production, with net imports therefore playing an increasingly important role in meeting demand.

Of particular note in this regard is the gap between US natural gas demand and production. EIA projects US natural gas production in 2030 of 21.15 tcf/year, compared with the 21.45 tcf/year projected in December 2005. After a 2015 peak at 4.6 tcf/year, EIA sees lower 48 offshore production declining to 3.3 tcf/year in 2030, as investment is inadequate to maintain production levels.

EIA, however, made an even larger downward revision in its projections of natural gas consumption in 2030, now pegged at 26.9 tcf/year vs. the 27.7 tcf/year projected a year earlier. High natural gas prices in the US will likely discourage construction of new natural-gas-fired electricity generation plants between now and 2030, with more coal-fired wattage planned instead.

Even so, net imports of natural gas will increase at a 1.5%/year between now and 2030 in order to meet the forecast 0.7%/year increase in natural gas consumption while production increases 0.5%/year.

Canada will remain the primary source of US natural gas imports until 2010, according to EIA, after which LNG will replace Canadian imports as the primary source. Production declines and a 1.9%/year growth rate in Canadian consumption will leave less Canadian gas available for export to the US.

LNG imports will, therefore, meet much of the increased demand for natural gas, with EIA's baseline projection seeing a more rapid increase in LNG imports than was projected a year earlier. Liquefaction project delays, supply constraints, and rapid growth in global LNG demand will keep the US LNG market tight until 2012, according to EIA.

Total net imports of LNG to the US in EIA's 2007 reference case will increase to 4.5 tcf/year in 2030 (0.2 tcf/year higher than the 2006 projection) from 0.6 tcf/year in 2005.

Regardless of how future natural gas enters the country, however, it will have to be brought to the end-user via pipeline, as will future unconventional domestic production and any new supplies from Alaska.

OGJ has for more than 50 years tracked applications for US gas pipeline construction to what is now called the Federal Energy Regulatory Commission. Applications filed in the 12 months ending June 30, 2006 (the most recent 1-year period surveyed), suggest a continued strength in terms of US interstate pipeline construction.

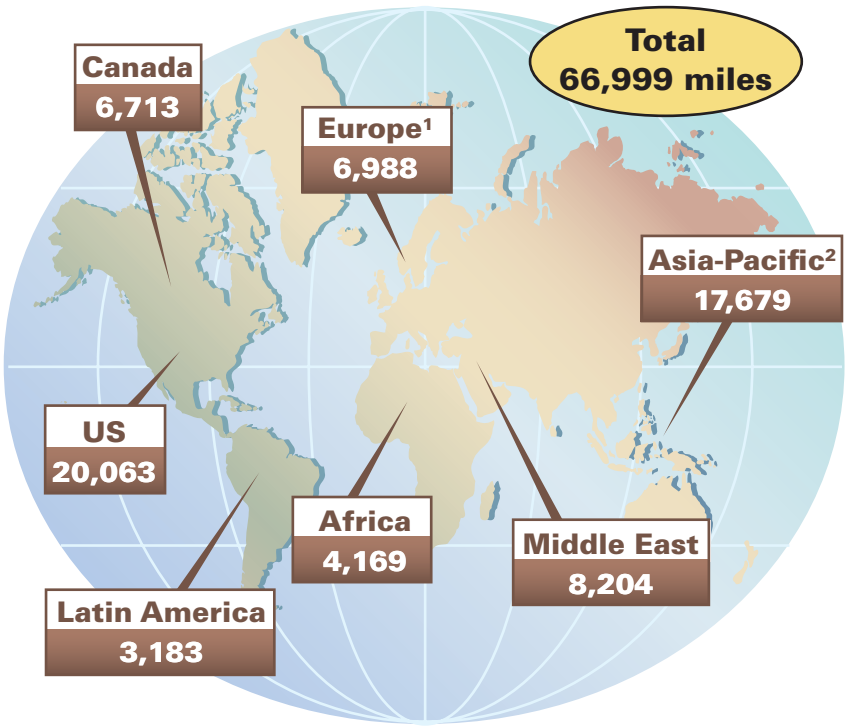
- Some 1,414 miles of pipeline were proposed for land construction, but only 6.23 miles were proposed for federal offshore work. For the earlier 12-month period ending June 30, 2005, more than 1,700 miles were proposed for land construction, with 91.8 miles proposed for offshore work.

Plans, however, remain well above the previous 12-month period ending June 30, 2004, when only 213 miles were proposed for land construction, with no miles proposed for expansions in federal waters.

- In contrast, FERC applications for new or additional horsepower at the end of June 2006 accelerated their recent surge, reaching more than 583,000 hp, all onshore, compared

FORECAST PIPELINE CONSTRUCTION

Fig. 1



[1]Including Russia and former Soviet republics west of the Ural Mountains. [2]Including Russia and former Soviet republics east of the Ural Mountains.

PIPELINE CONSTRUCTION IN [1]2007

Table 1

Area	4-10 in.	12-20 in.	22-30 in.	30+ in.	Total
			Miles		
Gas pipelines					
US	4	128	624	1,294	2,050
Canada	—	—	—	—	—
Latin America	115	174	136	75	500
Asia-Pacific[2]	—	438	1,832	634	2,904
Europe[3]	30	170	—	919	1,119
Middle East	—	—	228	251	479
Africa	130	—	—	—	130
Total gas	**279**	**910**	**2,820**	**3,173**	**7,182**
Crude pipelines					
US	52	176	100	—	328
Canada	—	—	50	—	50
Latin America	—	56	—	—	56
Asia-Pacific[2]	—	—	205	52	257
Europe[3]	20	—	140	—	160
Middle East	—	266	—	—	266
Africa	—	—	—	—	—
Total crude	**72**	**498**	**495**	**52**	**1,117**
Product pipelines					
US	23	462	—	—	485
Canada	—	—	—	—	—
Latin America	—	—	—	—	—
Asia-Pacific[2]	172	533	—	—	705
Europe[3]	—	560	—	—	560
Middle East	—	—	—	48	48
Africa	—	—	—	—	—
Total product	**195**	**1,555**	**—**	**48**	**1,798**
World totals					
Gas	279	910	2,820	3,173	7,182
Crude	72	498	495	52	1,117
Product	195	1,555	—	48	1,798
Total	**546**	**2,963**	**3,315**	**3,273**	**10,097**

[1]Projects under way at the start of or set to begin in 2007 and be completed in 2007. [2]Regions east of the Ural Mountains and south of the Caucasus Mountains, excluding the Middle East. [3]Regions west of the Ural Mountains and north of the Caucasus Mountains.

with nearly 175,000 hp of new or additional compression applied for a year earlier and 76,000 hp the year before that.

Notwithstanding the slight downturn in FERC applications, prospects for oil, natural gas, and products pipeline construction appear healthy (Tables 1 and 2), led by a surge in expected work in the US.

Bases, costs

For 2007 only (Table 1), operators plan to build more than 10,000 miles of oil and gas pipelines worldwide at a cost of $18.3 billion. For 2006 only, companies had planned more than 11,500 miles at a cost of more than $27.6 billion.

For projects completed after 2007 (Table 2), companies plan to lay nearly 57,000 miles of line and spend more than $107 billion.

When these companies looked beyond 2006 last year, they anticipated spending more than $116 billion to lay more than 50,000 miles of line.

- Projections for 2007 pipeline mileage reflect only projects likely to be completed by yearend 2007, including construction in progress at the start of the year or set to begin during it.
- Projections for mileage in 2007 and beyond include construction that might begin in 2007 and be completed in 2007 or later.

Also included are some long-term projects judged as probable (such as at least two pipelines competing to bring Arctic gas to the continental US), even if they will not break ground until after 2007.

US average cost-per-mile for onshore and offshore pipeline construction (Table 4, OGJ, Sept. 11, 2006, p. 46) on FERC applications submitted by June 30, 2006, was $1.9 million and $3.5 million, respectively.

Based on historical analysis and a few exceptions and variations notwithstanding, these projections assume that 90% of all construction will be onshore and 10% offshore and that pipelines 32 in. OD or larger are onshore projects.

Following is a breakdown of projected costs, using these assumptions and OGJ pipeline-cost data:

- Total onshore construction (9,415 miles) for 2007 only will cost more than $18 billion:
  - —$956 million for 4-10 in.
  - —$5.2 billion for 12-20 in.
  - —$5.8 billion for 22-30 in.
  - —$6.4 billion for 32 in. and larger.
- Total offshore construction (682 miles) for 2007 only will cost more than $2.4 billion:
  - —$192 million for 4-10 in.
  - —$1 billion for 12-20 in.
  - —$1.2 billion for 22-30 in.
- Total onshore construction (55,223 miles) for beyond 2007 will cost more than $107 billion:
  - —$1.5 billion for 4-10 in.
  - —$12.9 billion for 12-20 in.
  - —$14.9 billion for 22-30 in.
  - —$78 billion for 32 in. and larger.
- Total offshore construction (1,679 miles) for beyond 2007 will cost nearly $6 billion:
  - —$303 million for 4-10 in.
  - —$2.6 billion for 12-20 in.
  - —$3 billion for 22-30 in.

Action

What follows is a quick rundown of major projects in each of the world's regions.

Pipeline construction projects mirror end users' energy demands, and today much of that demand centers on natural gas, with much of the industry's focus being on how to get that gas to market as quickly and efficiently as possible. The following sections look at both natural gas and liquids pipelines.

North America

- *Natural gas.* Competing plans in the Bahamas to import LNG and then pipeline the gas to Florida have slowed, with three competing plans having narrowed to two.

The Calypso pipeline, proposed by Calypso US Pipeline LLC, a subsidiary

of Suez Energy North America Inc., is premised on the construction of an LNG terminal at Freeport Harbor on Grand Bahama Island. It would involve installation of 42.8 miles of 24-in. pipe in US territory from the boundary of the Exclusive Economic Zone between Florida and the Bahamas.

The 832-MMcfd project's estimated cost is $144 million, but discussions with the Bahamian government have slowed to the point that Suez is now planning an offshore Florida LNG port as an alternative. The facility would mirror the design of a Suez port planned for offshore Massachusetts and move gas ashore through a truncated version of the already FERC-approved pipeline.

The 842-MMcfd Ocean Express pipeline, proposed by AES Corp., is premised on the construction of an LNG terminal at Ocean Cay, an industrial site in the Bahamas. It would entail installation of 54.3 miles of 26-in. mostly subsea pipeline from the EEZ boundary to Florida.

Start-up is currently anticipated in mid-to-late 2008. Ocean Express' estimated cost is more than $264 million.

El Paso Corp. abandoned its own plans for a pipeline from the Bahamas to Florida, citing lack of shipper interest, unresolved environmental issues, and mounting fears the Bahamian government would never act on its application.

Elsewhere in North America, the race to bring Arctic gas south to major US consuming centers continued.

In late October 2005 Alaska signed an agreement with ConocoPhillips regarding the proposed Trans-Alaska Gas Pipeline. The pipeline would run more than 3,000 miles across Alaska, through western Canada, and into the US Midwest and carry 4.5 bcfd. The project is expected to cost $20 billion and projected to take at least 10 years to build.

The Alaskan governor's office eventually completed negotiations with the other two North Slope producers—BP PLC and ExxonMobil Corp.— but the resulting agreement was not passed by the state legislature.

Included in the state's proposal were a 30-year term, state ownership in the pipeline, and access to the gas for in-state use. Alaska said it would invest $4 billion in the project, $1 billion in cash and $3 billion in financing.

The governor's office has estimated that the pipeline could generate $2-3 billion/year in revenues for the state once it is operational.

In a February 2006 report, FERC said that further delay of the pipeline could hurt project economics, potentially opening the door for competing proposals. Such proposals could include the $16.1 billion All-Alaska Pipeline, designed to carry gas from the North Slope to a liquefaction plant in Valdez for subsequent shipment to the US West Coast. The project, however, would

PIPELINE CONSTRUCTION IN 2007 AND BEYOND[1]

Table 2

Area	4-10 in.	12-20 in	22-30 in.	30+ in.	Total
			Miles		
Gas pipelines					
US	61	355	1,867	8,972	11,255
Canada	31	7	1,020	1,657	2,715
Latin America	408	794	926	173	2,301
Asia-Pacific[2]	29	1,629	1,675	5,787	9,120
Europe[3]	—	57	454	3,312	3,823
Middle East	—	—	56	7,063	7,119
Africa	—	—	367	3,260	3,627
Total gas	**529**	**2,842**	**6,365**	**30,224**	**39,960**
Crude pipelines					
US	—	158	1,700	1,225	3,083
Canada	—	—	472	1,845	2,317
Latin America	—	76	—	—	76
Asia-Pacific[2]	54	29	—	4,610	4,693
Europe[3]	—	28	—	1,298	1,326
Middle East	—	186	—	—	186
Africa	—	—	—	412	412
Total crude	**54**	**477**	**2,172**	**9,390**	**12,093**
Product pipelines					
US	—	2,362	—	500	2,862
Canada	279	1,352	—	—	1,631
Latin America	—	250	—	—	250
Asia-Pacific[2]	—	—	—	—	—
Europe[3]	—	—	—	—	—
Middle East	—	106	—	—	106
Africa	—	—	—	—	—
Total product	**279**	**4,070**	**—**	**500**	**4,849**
World totals					
Gas	529	2,842	6,365	30,224	39,960
Crude	54	477	2,172	9,390	12,093
Product	279	4,070	—	500	4,849
Total	**862**	**7,389**	**8,537**	**40,114**	**56,902**

[1]Projects planned to begin in 2007 and be completed in 2008 or later. Includes some probable major projects whose installation will begin in 2008 or later. [2]Regions east of the Ural Mountains and south of the Caucasus Mountains, excluding the Middle East. [3]Regions west of the Ural Mountains and north of the Caucasus Mountains.

require an exemption to the Jones Act which requires that ships moving between US ports be US-built, US-owned and US-crewed.

A revised pipeline agreement is expected to dominate Alaska's 2007 legislative session. Gov. Sarah Palin has scrapped the previous contract and stated the she will open the project to parties beyond the state and the three original signatories.

In Canada, the proposed Mackenzie Valley pipeline would stretch more than 750 miles to transport Mackenzie River Delta gas to Alberta and beyond. Plans call for initial capacity of 1.2 bcfd, expandable to 1.8 bcfd. The project is currently in regulatory reviews.

Numerous issues remain unresolved, however, including land access arrangements. The Deh Cho First Nations aboriginal group in the southern part of the proposed route remains outside the Mackenzie Valley Aboriginal Pipeline Group, which owns 33.3% interest in the project. The other three aboriginal groups have joined the project. In addition to the Aboriginal Pipeline Group, other pipeline partners are Imperial Oil Ltd. 34.4%, ConocoPhillips Canada 15.7%, Shell Canada 11.4%, and ExxonMobil Canada 5.2%

In June 2006, Imperial put on hold its talks with the Canadian government regarding the pipeline, wanting to reassess its increasing costs and their effect on the project's viability. Third-party cost estimates for the project have grown to $10.5 billion (Can.) or more from $7 billion (Can.) filed by Imperial just 2 years ago.

The following month, the panels reviewing the project said that they would need an additional 5 months to complete their work. Associated delays have pushed start-up back to 2012 at the earliest, beyond both earlier projections that gas would be moving by 2011 and the originally filed estimate of 2009.

Large domestic west-to-east natural gas pipelines also continued to be planned in the US. The Rockies Express pipeline, running 1,323 miles of 42-in. pipe from Cheyenne, Wyo., and Colorado to Clarington, Ohio, is the largest new US pipeline project undertaken in 20 years. The 1.8 bcfd, $3 billion line has firm commitments in place for 900 MMcfd, including a binding 500 MMcfd by EnCana Corp. and a conditional 400 MMcfd from the Wyoming Natural Gas Pipeline Authority.

Kinder Morgan Energy Partners LP will operate the pipeline and owns two thirds of the project; Sempra Pipelines & Storage holds one third of it. In exchange for capacity commitments, some shippers may exercise options for equity in the project, which could give KMP a minimum of 50% and Sempra 25% after construction.

The pipeline, which KPM expects to be completed by June 2009, will be brought on line in three segments.

The first 710 miles, from the Cheyenne Hub in Colorado to an interconnection with Panhandle Eastern Pipeline Co.'s system in Audrain County, Mo., is scheduled to be in service Jan. 1, 2008. It will include transportation of gas from a capacity lease to Questar Corp.'s Overthrust Pipeline and any necessary expansion of Entrega Pipeline LLC, which KPM and Sempra purchased from EnCana Oil & Gas (USA) Inc.

The second segment, to be in service in January 2009, will continue to the Lebanon Hub in Ohio. The third segment, to the Clarington Hub in Ohio, is to be operational by June 2009.

Kinder Morgan Energy Partners LP and Energy Transfer Partners LP will jointly develop the Midcontinent Express Pipeline. The 1.4-bcfd pipeline will be about 500 miles long, originating near Bennington, Okla. It will run through Perryville, La., and terminate at an interconnect with Transco in Butler, Ala. Pending regulatory approvals, the $1.25 billion project will be in service by February 2009. MEP has prearranged binding commitments for 800 MMcfd, including a commitment from Chesapeake Energy Marketing Inc. for 500 MMcfd.

MEP has executed a firm-capacity

lease agreement for up to 500 MMcfd with Enogex to provide transportation from various locations in Oklahoma into and through MEP. The new pipeline will also interconnect with Natural Gas Pipeline Company of America and with the ETP 36-in. pipeline extending from the Barnett Shale and interconnecting with ETP's Texoma line near Paris, Tex.

CenterPoint Energy Gas Transmission Co. and Spectra Energy signed a memorandum of understanding to lay a natural gas pipeline from the Waha hub in West Texas to as far away as Oakford-Delmont, Pa. Previously, CenterPoint launched an open season for Midcontinent Crossing pipeline stretching from Dumas, Tex., to Barton, Ala. Potential shippers expressed interest in extending the proposed pipeline to the US Northeast and became involved because its Texas Eastern Transmission system has pipeline rights-of-way from Arkansas to Pennsylvania.

The 1,600 mile, 42 and 36-in. pipeline was to have a capacity of 1.5-1.75 bcfd and be in service as early as late 2008. CenterPoint and Spectra, however, called off development of the project earlier this month.

• *Crude oil.* Export lines for Canadian crude continued to progress. TransCanada Corp.'s proposed 1,840-mile Keystone pipeline project is designed to transport 435,000 b/d of crude oil from Hardisty, Alta., to Patoka, Ill. In early November 2005 ConocoPhillips signed a memorandum of understanding committing to ship oil on the line, saying that the pipeline would further integrate its upstream assets in Canada with its Wood River, Ill., refinery. The MOU also gave ConocoPhillips Pipe Line Co. the right to acquire as much as 50% ownership in the $2.1 billion pipeline.

Firm long-term shipping contracts for 340,000 b/d, with an average duration of 18 years, were secured in January 2006, prompting TransCanada to move forward with regulatory filings. These filings included a June 2006 application with the National Energy Board for transfer of a 530-mile segment of TransCanada's Canadian Mainline gas pipeline into service as part of Keystone.

In addition to the 530 miles of converted line, the Keystone system will include about 1,100 miles of new pipeline in the US and 230 miles of new pipeline in Canada. TransCanada filed its application to construct the Canadian section in December 2006.

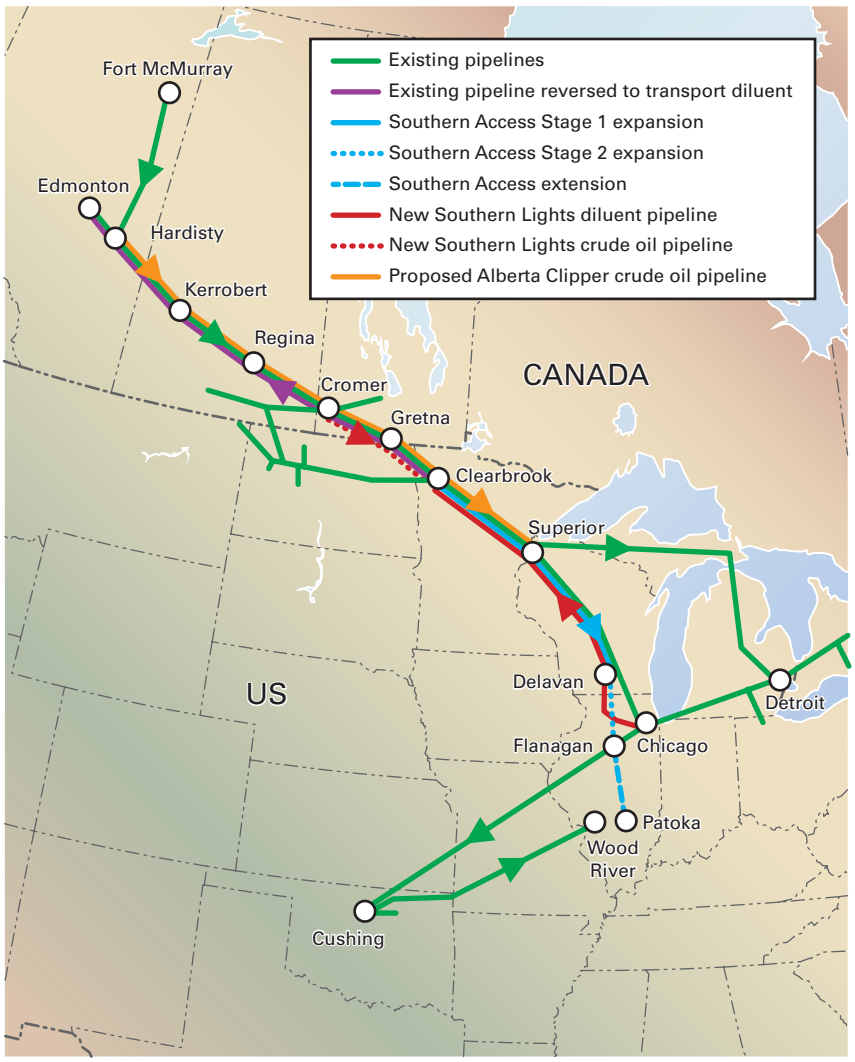
TransCanada has also hosted open houses concerning a proposal to extend Keystone from Patoka to Cushing, Okla. The Cushing Extension would add about 291 miles of pipe through Nebraska, Kansas, and Oklahoma at an estimated $445 million.

TransCanada plans to have the pipeline in service in 2009.

The Keystone project is one of two competing major systems planned to

ENBRIDGE EXPANSION PROJECTS

Fig. 2



Source: www.enbridge-expansion.com

deliver crude oil from Hardisty to the US Midwest. Enbridge Energy Partners LP, also of Calgary, plans its own pipeline expansion to deliver 400,000 b/d of crude oil to the US.

The proposed Southern Access system expansion will use 42-in. pipe to allow for future expansions of as much as 800,000 b/d on its Canadian mainline from Hardisty, Alta., to the international border near Neche, ND, and new pipeline construction in the US. The new pipeline will be added between Superior, Wis., and Flanagan, Ill., just west of Chicago, on Enbridge's Lakehead system (Fig. 2).

The US portion of the expansion will cost $1.04 billion and take place in the three stages. The first stage will add 44,000 b/d of capacity in 2007. An additional 146,000 b/d will be added by early 2008, with the final 210,000 b/d entering service in early 2009.

At Flanagan, the new line will have access to Chicago and will interconnect with Enbridge Inc.'s Spearhead pipeline, which began deliveries to Cushing, Okla., Mar. 1, 2006.

Enbridge also announced in July 2006 that it would construct a $350 million extension to Southern Access, running 286 km of 36-in. pipe from Flanagan south to Patoka, Ill. Construction of the 400,000-b/d line remains subject to regulatory approval. It is expected to begin service as early in 2009 as possible and can later be expanded to 800,000 b/d through the addition of pumps.

Accompanying the Southern Access expansion is Enbridge's Southern Lights 180,000-b/d Chicago-to-Edmonton diluent pipeline. Shippers have committed to 162,000 b/d, with the balance retained for spot suppliers. Enbridge will build 674 miles of 16 or 20-in. pipe from the Chicago area to Clearbrook, Minn. Enbridge will reverse the flow of its existing Line 13 to carry the diluent from Clearbrook to Edmonton, replacing this volume with a new 20 or 24-in., 185,000 b/d pipeline from Cromer, Man., to Clearbrook and an expansion of its existing Line 2 (Fig. 2).

Preliminary cost estimates for Southern Lights, expected to be in service in 2009, are near $920 million.

Beyond these two projects, Enbridge intends to file a project proposal with NEB early this year for the Alberta Clipper 36 in., 1,000-mile crude oil pipeline with a planned capacity of 450,000 b/d. The line would parallel Southern Access-Southern Lights from Hardisty to Superior; work on it would only begin once the other two projects were complete.

Even with these projects, however, Canadian officials have said that pipeline capacity could pose a greater constraint on future Canadian oil sands development than water or natural gas availability. "Pipeline capacity will be tight by 2007. There will be need for some incremental increases from then until 2009. Beyond that, more capacity will be needed," said Colette Craig, a resource analyst with the NEB (OGJ Online, June 6, 2006).

Enterprise Products Partners LP signed definitive agreements with producers to construct, own, and operate an oil export pipeline to provide firm gathering services from BHP Billiton-operated Shenzi field located in South Green Canyon, Gulf of Mexico. The 83 mile, 20-in. pipeline will have the

capacity to transport 230,000 b/d and will connect the field to the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems.

BHP Billiton expects Shenzi production to begin in mid-2009.

Also in Green Canyon, Chevron USA Inc. approved construction of a 55-mile deepwater oil pipeline for its Tahiti project. The company also approved expanding the pipeline from an initially planned 20 in. to 24 in. to handle 300,000 b/d of oil and accommodate additional discoveries in the Walker Ridge and Green Canyon areas.

Tahiti is to start production in 2008.

• *Products.* Overland Pass Pipeline Co. LLC, Tulsa, plans to build a 750 mile, 14 and 16-in. NGL pipeline from gas processing facilities in the Rocky Mountains to a market hub in Central Kansas. The $450 million pipeline will extend from Opal and Echo Springs, Wyo., to fractionation facilities at Bushton and the Conway-Midcontinent NGL market and storage hub. The pipeline will be baseloaded by 110,000 b/d Williams expects its Opal and Echo Springs, Wyo., plants to be producing by 2008. Capacity can be increased to 150,000 b/d by addition of pumping facilities.

Overland Pass intends to start construction in summer 2007 and anticipates that the pipeline will be operational by December 2007. The new company is a joint venture between Williams and Northern Border Partners LP. Northern Border holds a 99% interest in the pipeline and has agreed to reimburse Williams for development costs to date. Williams has an option to boost its 1% interest to 50% and become operator within 2 years of start-up.

Colonial Pipeline Co. received assurance from FERC encouraging it to invest $1 billion in expanding its mainline petroleum products pipeline. To ease constraints on its system, Colonial plans to construct and operate 500 miles of 36-in. pipeline between Louisiana and Georgia to transport at least 800,000 b/d, a 30% increase in capacity. Colonial estimates the project will enter service in 2010.

Kinder Morgan Energy Partners LP plans to invest $388 million further to expand its 550-mile Calnev pipeline, which transports petroleum products from California to Nevada. The proposed expansion, involving construction of a 16-in. pipeline from Colton, Calif., to Las Vegas, Nev., will increase system capacity to 200,000 b/d, transporting products for Nellis Air Force Base. Following its completion, the existing 14-in. line will be transferred to commercial jet fuel service for McCarran International Airport and any future airports planned in Las Vegas.

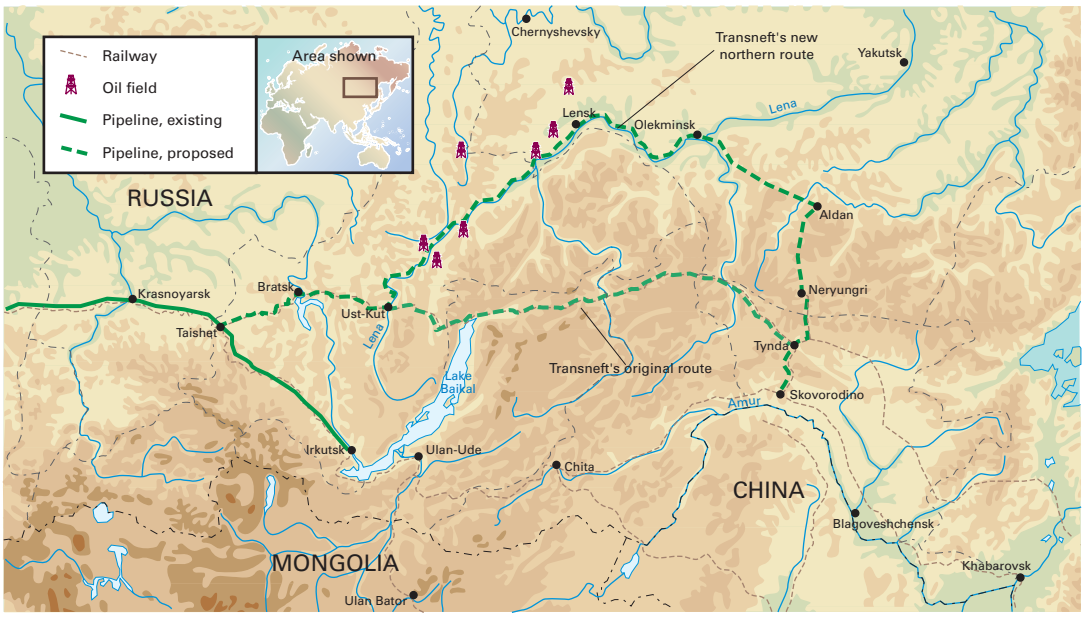
Pending FERC approvals, start-up of the line is set for late 2009 or early 2010.

Latin America

Intergovernmental meetings continued to be held in 2006 regarding construction of a 7,776-mile pipeline to transport natural gas from Venezuela to

ORIGINAL, NEW ESPO PIPELINE ROUTES

Fig. 3



Source: Centre for Global Energy Studies/Market Watch

Argentina through Brazil, Uruguay, and Paraguay. The line would cost $23 billion and could take 5 years to construct.

Talks culminated in the January 2007 signing of a declaration between Brazil and Venezuela authorizing construction of the pipeline's first leg, with construction to begin in 2009.

The first 2,950 km (1,832 miles), from Puerto Ordaz, Venezuela, to Maraba, Brazil, calls for 66-in. OD pipeline with 13 compressor stations of 25,000 hp each and 11 city gates. The diameter of the line would gradually decrease to 32 in. as it crosses Brazil from Maraba to Fortaleza to the existing pipeline system that extends along the coast to Salvador, Bahia state.

From Salvador, Petróleo Brasileiro SA is building the Gasene line to Brazil's north and south systems. Petrobras is investing $3.9 billion in 3 years to build 4,191 km of pipelines as part of this separate domestic project.

A second branch, the main transmission line, would continue south from Maraba in a 1,977 km stretch of 54-in. OD pipe to Sao Paulo state. It would include eight 20,000-hp compression stations and 20 city gates and distribute 42 million cu m/day (MMcmd) in Sao Paulo.

From Sao Paulo the pipeline would be routed to the border between Rio Grande do Sul state and Uruguay and cross Uruguay to Argentina in an 1,875-km section of 38-in. pipe. This section, including eight 15,000-hp compressor stations and 20 city gates, would transport 50 MMcmd, according to study estimates.

Petrobras signed an accord with Goias state to build the country's first ethanol pipeline, a $226 million, 975-km line to transport 4 billion l./year. The pipeline will run from Goias to a refinery in Paulinia, near Sao Paulo.

Tidelands Oil & Gas Corp received permitting from the Mexican government for both the Occidente and Oriente sections of its proposed Terranova pipeline, itself part of the Burgos Hub Export-Import Project. The Occidente section will use 323 km of 30-in. pipe, running from Brasil storage field to Nuevo Progresso, Mexico, with a proposed international pipeline crossing into South Texas from Mexico at the Donna station.

This crossing will allow interconnections with TETCO, TGPL, and Texas Gas Services. The pipeline will also include a stretch from Brasil to Arguelles, where another proposed crossing into South Texas would facilitate interconnection with Houston Pipeline, Calpine, and Kinder Morgan.

The Oriente section will use 36-in. line spanning 149 km. It will run from a proposed offshore LNG regasification terminal to Norte Puerto Mezquital and from there to the Brasil storage field.

Both lines are designed to flow natural gas bi-directionally between Texas and Mexico at a rate of 1.2 bcfd.

Asia-Pacific

Oil Search Ltd. and Malaysia's Petronas, partners in the proposed Papua New Guinea-Australia natural gas pipeline, decided to scale back front-end engineering and design activities on the pipeline's Australian leg even though most budgeted FEED activities had already been completed. AGL cited a dearth of critical foundation customers and escalating costs as the reasons for deciding to table the project, adding that the pipeline is unlikely to proceed without an alternative ownership structure.

The proposed $5 billion (Aus.) Highlands natural gas pipeline would have extended 3,600 km from Papua New Guinea to Queensland, Australia.

Earlier this month, however, Oil Search abandoned the project, maintaining that costs and returns were no longer attractive.

Industrial growth in Western Austra-

lia prompted an increase in the size of the proposed Stage 5 expansion of the Dampier-Bunbury natural gas trunkline to handle an additional 375 terajoules/day of natural gas expected to come online in 2007-09. This will require laying 1,150 km of pipeline alongside the existing pipe at an estimated cost of $1.5 billion (Aus.).

The Indonesian government tendered in January 2006 for the construction of a 1,219-km natural gas pipeline between Bontang in East Kalimantan and Semarang in Central Java. The pipeline, estimated to cost $1.7 billion, would carry 700-1,000 MMcfd of natural gas.

PT Bakrie & Bros. won the tender to build and operate the pipeline and in December 2006 said it plans to proceed with the project despite doubt voiced by officials about its feasibility. In January 2007 Indonesian officials said that they were awaiting the publication of reliable figures on the country's natural gas reserves before deciding whether to proceed with this line. Attention focused on Cepu gas field in Central Java, development of which might make the pipeline redundant.

PT Perusahaan Gas Negara will build its South Sumatra to West Java Transmission Pipeline Project in two stages. Stage 1 will use 375 km of 32-in. pipe to move gas from Pagardewa (South Sumatra) to Cilegon (Banten). Stage 2 will transport natural gas from Pagardewa to Labuhan Maringgai (South Sumatra) and from Muara Bekasi (West Java) to Rawa Maju (West Java) using 100 km of 28 and 32-in pipe.

Indonesia is also considering plans for a 220-km natural gas pipeline between Cirebon and Bekasi in West Java at a cost of $200-300 million.

In Kazakhstan, the government is considering construction of a 20 billion cu m/year Trans-Caspian gas pipeline from Aktau to Baku, with the intent of connecting to the Baku-Tbilisi-Erzurum pipeline. Estimated cost of the project is $3-4 billion.

In China, PetroChina obtained approval from the Chinese government to lay two pipelines to carry oil products from the northern areas of China to the country's central regions. PetroChina said it will spend about $1.5 billion to construct the two lines, which could be operational before the end of 2007.

One pipeline will extend from Lanzhou, in northwest China's Gansu province, and carry 8 million tonnes/year of products. The other pipeline will begin in Jinzhou, in northeast China's Liaoning province, and carry as much as 4 million tonnes/year.

The two lines will meet in Zhengzhou, in the central province of Henan. A planned extension will reach Changsha, the capital city of Hunan province, south of Henan. The pipelines will transport products from refineries processing crude oil received by pipeline from Kazakhstan and Russia.

Kazakhstan and China also agreed in August 2005 to build a 40 to 48-in. natural gas pipeline running from western Kazakhstan to China.

China's own West-East Gas Pipeline, running 4,000 km from the Xinjiang Uygar Autonomous region to Shanghai and other eastern provinces, entered service in 2004.

The Chinese government is expanding the line to 17 billion cu m/year from 12 billion cu m/year, requiring additional compression.

Kazakhstan is not the only country actively pursuing export projects to China. In early September 2005, Russian President Vladimir Putin confirmed that the long-discussed crude pipeline from Taishet, Siberia, would run to China first, and only later be extended to the Pacific for exports to Japan.

The first stage of the 4,188-km project called for construction of a 2,400-km oil pipeline from Taishet to Skovorodino near the Chinese border and of a rail oil terminal at the Perevoznaya Bay at a combined cost of $7.9 billion. The second stage, depending on development of Eastern Siberian oil fields, involves construction of a pipeline link between Skovorodino and Perevoznaya on Russia's Pacific Coast.

China looks to import as much as 30 million tonnes/year of crude if a pipeline spur is built from Skovorodino to Daquing, while supplies along the Skovorodino-Perevoznaya route would total 50 million tonnes/year, the bulk of which would be exported to Japan.

In February 2006, however, Russia's environmental safety supervisory body rejected the proposed route of the pipeline, which would have taken it within 1 km of Lake Baikal, the world's largest, oldest, and deepest freshwater lake and home to 20% of the world's fresh water.

The new route is 350-400 km from Lake Baikal but added 1,920 km to the pipeline's overall length (Fig. 3). Despite this officials remained confident that the project would be completed by December 2008.

Last month, Russia's state-owned OAO Transneft reported it had constructed about 530 km of the pipeline. The company plans to lay about 1,250 km in 2007.

The May 2006 agreement over the pipeline route opened the way for exploratory work, the preparation of a technical and economic feasibility study for the projects, and a determination of the line's final cost. China and Russia began feasibility studies on construction of the spur from Skovorodino to the Chinese border in October 2006.

Russia is also considering construction of an 8 billion cu m/year natural gas pipeline from Okha, Sakhalin Island to China, much of which would parallel a line between Sakhalin and Khabarovsk, Russia, before crossing the border into China.

Construction on several sections of the Sakhalin-2 onshore pipeline system was halted in October 2006 as Russia voiced concerns that environmental laws were being violated. In December, OAO Gazprom agreed to acquire, for $7.45 billion, a 50%-plus-one share stake from Sakhalin-2 project operator Sakhalin Energy Investment Co. Ltd.—Royal Dutch Shell PLC, Mitsui & Co., and Mitsubishi Corp.

Finally, Turkmenistan and China held talks in June 2006 regarding construction of a natural gas pipeline from

eastern Turkmenistan to China and joint development of Turkmen gas fields to fill the line. The pipe, planned to begin operations in 2009, would move 30 billion cu m/year.

Turkmenistan also agreed to supply 3.2 bcfd of natural gas to Pakistan over 30 years via the proposed $3.3 billion Turkmenistan-Afghanistan-Pakistan pipeline. India, which attended February 2006 meetings as an observer and earlier had been invited to join the project, expressed its willingness to participate in the 1,680-km pipeline.

A 735-km Afghan segment lies between a 145 km Turkmen length and the final 800 km through Pakistan. An extension off this line is one of the possibilities China and Turkmenistan are considering in their plans.

Europe

Work started in early December 2005 on the Russian onshore section of the North European Gas Pipeline in Babayevo. This 56-in. segment will stretch 917 km to the Baltic Sea coast near Vyborg, linking existing gas pipelines from Siberia to the NEGP project. Seven compressor stations will provide the necessary pressure. The pipeline will cross the Baltic, making landfall near Greifswald, Germany. This section will be 1,200 km in length with a 48-in. OD.

The full system is scheduled to start operations in 2010 at a capacity of 27.5 billion cu m/year. The project includes the possibility of building a second, parallel pipeline, doubling capacity to about 55 billion cu m/year.

A joint venture consisting of Gazprom (51%), BASF AG (24.5%), and E.ON AG (24.5%) is building the pipeline. For the two-leg option, the total cost for the offshore project will amount to more than $4 billion (Euro), with Gazprom investing an additional $1.3 billion (Euro) in the onshore section.

The Netherlands, Gaz de France, and Finland have also voiced interest in participating in the project.

Gasunie plans to expand the gas transport network in the Netherlands by 500 km of pipe and four compressor stations at a cost of €1.5 billion. Expansion activities will be focused on the route from northeast Netherlands to southwest Netherlands. Construction is expected to start in 2009 for completion in 2012.

Gazprom is considering an expansion of its Blue Stream natural gas line between Russia and Turkey. The $3.2 billion initial pipeline moved 5 billion cu m of gas in 2005 and is to carry 16 billion cu m/year by 2010.

Medgaz is set to begin construction of the 8 billion cu m/year Algerian-European gas pipeline bearing the same name early this year, having received all regulatory approvals within the scheduled time frames. The project is expected to cost €900 million, with start-up slated for 2009. This figure includes past costs of the project, construction, start-up, and preinstallation of future

North American LNG-driven pipeline projects

With the expectation of continued growth in LNG imports to the US have come a number of pipeline projects to move regasified material from the terminal to centers of consumption. Brief summaries of some these projects appear below.

• *Elba Express.* El Paso Corp. subsidiaries will expand the Elba Island LNG receiving terminal near Savannah, Ga., and lay the related Elba Express pipeline. The projects, costing $850 million, will start service in 2010. El Paso unit Southern Natural Gas Co. will construct, own, and operate the 191-mile, 1.1-bcfd interstate pipeline. The new line, carrying gas northwest from the terminal, will consist of 105 miles of 42-in. pipeline and 86 miles of 36-in. pipeline.

• *Jordan Cove.* An equal partnership of Fort Chicago Energy Partners LP of Calgary, Northwest Pipeline Corp., and Pacific Gas & Electric Co. plans to build a 250-mile pipeline from the Jordon Cove LNG receiving terminal and regasification plant being developed by Fort Chicago at Coos Bay, Ore.

The pipeline, scheduled for completion in 2010, would be able to deliver 1 bcfd of natural gas to the Pacific Northwest and beyond, including California and northern Nevada through existing systems.

• *Kinder Morgan Louisiana Pipeline.* This pipeline will provide about 3.2 bcfd of take-away capacity from the Cheniere Sabine Pass LNG terminal under construction in Cameron Parish, La. KM will invest about $500 million to build this pipeline to Evangeline Parish, La.

The pipeline will consist of two segments: a 137-mile large-diameter pipeline with firm capacity of about 2 bcfd that will connect to various interstate and intrastate pipelines within Louisiana, and a 1-mile pipeline with firm capacity of about 1.2 bcfd that will connect to KM's Natural Gas Pipeline Company of America's pipeline. Pending regulatory approval, KM expects the NGPCA lateral to be in service by Oct. 1, 2008.

• *Brunswick Pipeline.* As much as 850 MMcfd of gas will flow from the Canaport LNG terminal near St. John's, NB, via the proposed 145 km, 30-in. Brunswick Pipeline to a connection with the Maritimes & Northeast Pipeline system at the US border near Baileyville, Me. Construction is scheduled to begin this year and be completed by late 2008.

• *Cameron Interstate Pipeline.* This proposed 36-mile interstate pipeline will interconnect the Cameron LNG receipt terminal being developed in Cameron, La., by Sempra LNG on the Calcasieu Channel in Cameron Parish, La., to seven intrastate and interstate pipelines that transport natural gas to major market areas in the Midwest and Northeast. Cameron Interstate Pipeline will have a capacity of 1.5 bcfd of natural gas and is planned to go into service in 2008.

• *Cove Point LNG.* Dominion Cove Point LNG LP proposed to construct and operate about 47 miles of 36-in. loop pipeline in Calvert, Prince George's, and Charles County, Md., as part of its terminal expansion to allow it to deliver an additional 800 MMcfd from the terminal to its connections with other interstate pipelines. Dominion also proposed construction of about 81 miles of 24-in. pipeline lateral in central Pennsylvania and 33 miles of pipe in other parts of Pennsylvania and West Virginia as part of the expansion. Dominion expects the expanded capacity to be in service by 2008.

• *Energía Costa Azul.* Sempra LNG will build a 45 mile, 42-in. spur line and an additional 10 miles of 24-in. line as part of its Energía Costa Azul LNG project on the northern Baja peninsula in Mexico. The 42-in work is to be completed by Aug. 15, 2007, and the 24-in. work by Dec. 14, 2007.

extension points in the coastal section.

Medgaz' offshore length is 210 km and it will reach a maximum water depth of 2,160 m. Supplies will come from the Hassi R'Mel-Beni Saf gas pipeline operated in Algeria by Sonatrach. Upon landfall in Spain, the pipeline will link with the Almería-Albacete gas pipeline operated by Enagas, facilitating its connection to the Spanish and European gas grid.

Plans to export Algerian gas via Italy have also progressed, new gas-purchase agreements by five Italian energy companies having been concluded in November 2006.

The companies, Enel, Edison, Hera, Ascopiave, and Worldenergy, agreed to import a total of 6 billion cu m/year of gas from Algeria via the proposed Galsi pipeline connecting Algeria with Italy by way of Sardinia.

Sonatrach of Algeria, Enel, and Wintershall of Germany formed a venture to study feasibility of the pipeline in December 2001.

The project envisions four pipeline segments: 640 km onshore between Hassi R'mel gas field in Algeria and El Kala on the Algerian coast; 310 km between El Kala and Cagliari on Sardinia in water as deep as 1,950 m; 300 km between Cagliari and Olbia on the northern Sardinian coast; and 220 km between Olbia and Pescaia, southeast of Florence, in water as deep as 900 m.

Sonatrach says the Galsi pipeline will have a capacity of 8 billion cu m/year and projects start-up at the end of 2009.

Austria's OMV Akteingesellschaft continues to advance the 56-in. Nabucco pipeline, which will bring Central Asian and Caspian gas to the Baumgarten hub in Austria near the Slovakian border at 31 billion cu m/year before moving it on to Western Europe.

The €4 billion pipeline, spanning 2,000 miles, is to be completed by the

end of the decade. The European Commission has given its backing to the proposal and will accelerate commercial, regulatory, and legal work to build the pipeline.

Middle East

Iran, Pakistan, and India continued discussions toward building the long-contemplated gas export line from Iran to India during 2006. Gazprom has also expressed interest in participating in the $7 billion project, which would transport as much as 120 MMcmd of natural gas from the South Pars field in the Persian Gulf through 2,100 km of 56-in. OD line. (Iran, 1,100 km; Pakistan, 750 km; India, 250 km).

Natural gas pricing disagreements have so far worked against the project, joining already-present forces such as security concerns and pressure from the US. Iran has stated that the gas price expected by India is unacceptable. Iran is looking for $7.20/MMbtu, with 3% annual hikes, with India seeking $4.25/MMbtu.

Pakistan has indicated a requirement of 60 MMcmd and might join with India in a joint price proposal. Last month, however, elected Pakistani officials cited Iranian red tape as the reason the pipeline has yet to progress.

The Dolphin Gas Project, which includes twin 36-in. subsea lines running 80 km from Qatar's North field to the Ras Laffan treatment plant and a 48 in., 364-km subsea export line to Tawilah, Abu Dhabi, and Jebel Ali, Dubai, is nearing completion following protests from Saudi Arabia regarding the Qatar-UAE leg of the pipelines crossing of Saudi territory. The $3.5 billion project's initial planned capacity is 2 bcfd. The pipeline, however, would have the capacity to carry nearly 3.2 bcfd if demand justifies it. Qatar plans to export 200 MMcfd to Oman starting in 2008.

National Iranian Gas Co. plans steady pipeline growth, much of which will be additions to the Iranian Gas Transmission domestic pipeline system. IGAT lines IV-VIII will encompass more than 3,900 km of 42-56-in. transmission line and associated trunks.

Outside of this sytem, to meet growth in gas demand in the northern and eastern provinces of Semnan, Khorasan, Golestan, and Mazandaran, NIGC plans a 790 km, 48-in. pipeline between Parchin and Sangbast, and a 110 km, 40-in. line between Miami and Jajarm. The system will have four compressor stations and will handle South Pars gas delivered through IGAT VIII.

To serve the western and northern provinces of Hamadan, Kordestan, Zanjan, and Western and Eastern Azerbaijan provinces, NIGC plans to lay 280 km of 48-in. pipeline between a compressor station at Saveh and the city of Bijar and 192 km of 40-in. pipeline between Bijar and Miandoab. Four compressor stations are planned. Other segments with diameters of at least 30 in. will boost pipeline lengths planned for this region to 950 km.

AMEC PLC began work in 2006 on a $200-million pipeline in Yemen from a natural gas field close to the town of Marib to an LNG terminal being built close to Bal Haf on the Gulf of Aden. The project will involve construction of 320 km of 38-in. gas pipeline and 25 km of 20-in. line. Work on the 6.7 million tpy system is now expected to be completed in 2009, a dispute between Hunt Oil Co. (an 18% participant in the project) and the Yemeni government having delayed the start of construction.

Calvalley Petroleum Inc. will build and operate 250 km of 16-in. crude oil pipeline in Yemen between Blocks 9 and 18, crossing several development areas before reaching a tie-in to an export pipeline already in place running from Block 18 to the Ras Isa terminal on the Red Sea.

Saudi Aramco signed two lump-sum turnkey contracts with subsidiaries of J. Ray McDermott SA, which include engineering, procurement, fabrication, and installation of the offshore Safaniya TP-18 tie-in platform, due online in December 2007, and a 24-in. pipeline between the new platform and a subsea connection with a new 42-in. trunkline flowing to the onshore Safaniya GOSP-1 separation facility.

The second contract is associated with the 22 km subsea portion of the new 66 km, 30-in. BKTG-1 pipeline, which will transport 220 MMcfd of gas from the Abu Ali plant to the Khursaniyah gas plant. The subsea portion will be installed by May 2007.

Africa

Nigeria and Algeria met in October 2006 to discuss implementation of the 4,400 km Trans-Saharan Gas Pipeline. Their respective national oil companies, Sonatrach and Nigerian National Petroleum Corp., signed a joint-venture agreement to conduct a feasibility study of the $7 billion project in 2005. Gas would flow north to Algeria at a rate of 25 billion cu m/year and then on to Europe.

Installation of the 353-mile main offshore segment of the West African Gas Pipeline was completed in 2006. The estimated $560 million project is the first regional natural gas transmission system developed in sub-Saharan Africa. First gas delivery depends on completion of tie-ins and onshore facilities.

Sonatrach has secured 30-in. X-60 pipe for the 665 km NK-1 Haoud el Hamra-to-Skikda oil pipeline.

A Korean consortium led by state Korea National Oil Corp. agreed to build a 745-mile gas pipeline from the Niger Delta to Abuja, as well as associated power generation facilities, in return for production sharing rights with NNPC on deepwater oil exploration Blocks 321 and 323.

Global Offshore International Ltd. received a letter of intent from Perenco Gabon SA to build the latter's $50 million Societe d'Energie et d'Eau du Gabon pipeline project. Global's contract includes transportation, installation, and precommissioning of one 8 in. 108-km gas pipeline, one 10 in. 98-km gas pipeline, and associated shore landings. Global will mobilize its Cheyenne and Comanche pipelay barges in May 2007 for installation in water up to 30 m deep along the Gabonese coast. ✦

New portable unit for onshore, offshore inspection uses

The new phased array flaw-imaging Phasor XS promises to help reduce inspection times and improve probability of detection.

The company says the portable unit is particularly suited for onshore and offshore inspection of pipelines, pressure vessels, and supporting structures.

With its operating platform and easy-to-understand, menu-driven inspection instructions, the new battery-powered instrument requires little operator training. The firm says this instrument brings phased array technology to routine manual inspection, such as weld examination.

When used in phased array mode, the instrument offers as many as 64 channels, and the operator can electronically multiplex a multielement probe to achieve precise control over the angle of inspection, the amplitude, and the depth of focus of each individual ultrasonic beam. The inspection image is presented as a full color, sector B-scan on the unit's high resolution TFT screen, providing comprehensive data in real time. Any of the A-scans that make up the sector scan can be selected for separate display or for simultaneous display with the sector image to allow instant and reliable sizing. Sector images and A-scans can be stored on a removable SD card for off-line data analysis and management.

A range of array probes is compatible with the new flaw detector, including dialog probes, containing probe identification data that can be transmitted back to the instrument to ensure increased inspection reliability, minimize setup errors, and assist in probe operation calculations. In conventional mode, the Phasor XS can use standard ultrasonic probes to carry out conventional inspection, including corrosion and thickness measurement.

Weighing less than 4 kg, the Phasor XS offers an entry-level phased array solution to manual volumetric inspections from the fabrication yard and onshore processing plant to the offshore production platform and pipelines in the harshest of environments.

Source: **GE Inspection Technologies LP**, 50 Industrial Park, Lewistown, PA 17044.

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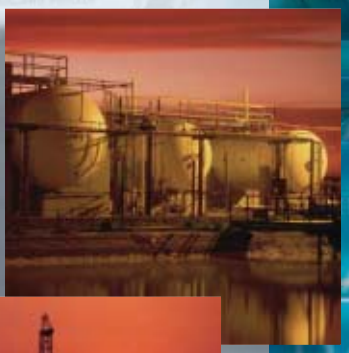

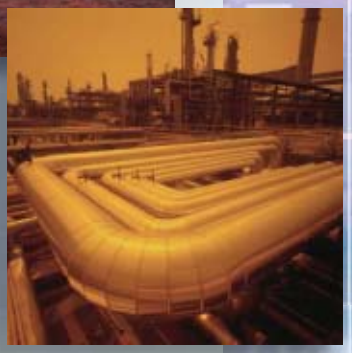

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	Current	Historical 1996–Current
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Petrochemical	E1341 $395.00 US	E1341C $1,495.00 US
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Production Projects Worldwide — List of planned production mega-projects Location, Project Name, Year, Production Volume, Operator and Type
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Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	2-9 2007	[1]2-2 2007	2-9 2007	[1]2-2 2007	2-9 2007	[1]2-2 2006	2-10 2006
	1,000 b/d						
Total motor gasoline	218	170	21	45	239	215	105
Mo. gas. blending comp.	492	475	69	73	561	548	259
Distillate[2]	286	261	9	9	295	270	596
Residual	72	136	89	23	161	159	490
Jet fuel-kerosine	272	88	128	146	400	234	160
LPG	230	314	2	3	232	317	357
Unfinished oils	614	473	54	71	668	544	602
Other	455	326	15	15	470	341	350
Total products	**2,639**	**2.243**	**387**	**385**	**3,026**	**2,628**	**3,009**
Canadian crude	1,517	1,722	129	26	1,646	1,748	1,809
Other foreign	6,748	6,394	711	882	7,459	7,276	8,794
Total crude	**8,265**	**8,116**	**840**	**908**	**9,105**	**9,024**	**10,603**
Total imports	**10,904**	**10,359**	**1,227**	**1,293**	**12,131**	**11,652**	**13,612**

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

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OGJ CRACK SPREAD

	*2-9-07	*2-10-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	67.48	64.31	3.17	4.9
Brent crude	57.63	61.23	–3.60	–5.9
Crack spread	9.85	3.08	6.78	220.2
FUTURES MARKET PRICES				
One month				
Product value	68.23	67.44	0.79	1.2
Light sweet crude	58.99	63.04	–4.05	–6.4
Crack spread	9.24	4.40	4.84	110.1
Six month				
Product value	73.97	77.02	–3.05	–4.0
Light sweet crude	61.94	66.37	–4.43	–6.7
Crack spread	12.03	10.65	1.38	12.9

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	12,310	59,030	29,008	10,167	58,621	18,626	8,364
PAD II	66,852	51,822	15,423	7,484	27,908	1,675	12,488
PAD III	180,272	66,178	26,807	13,674	33,975	16,717	43,219
PAD IV	14,033	7,103	1,775	499	3,071	353	2,594
PAD V	[1]51,784	31,297	22,986	9,606	11,543	6,572	19,734
Feb. 9, 2007	**[1]325,251**	**215,430**	**95,999**	**41,430**	**135,118**	**43,943**	**86,399**
Feb. 2, 2007[3]	**328,618**	**216,033**	**96,486**	**40,530**	**135,340**	**45,093**	**85,929**
Feb. 10, 2006	**328,979**	**219,675**	**78,204**	**43,503**	**137,350**	**40,122**	**87,723**

[1]Included in total motor gasoline. [2]Includes 4.215 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—FEB. 9, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,134	1,365	1,367	1,618	84.5	1,634	88	492	129
App. Dist. 1	83	75	75	95	79.0	17	0	17	0
Dist. 1 total	**3,217**	**1,440**	**1,442**	**1,713**	**84.2**	**1,651**	**88**	**509**	**129**
Ind., Ill., Ky.	2,152	2,100	2,146	2,355	91.1	1,187	160	576	48
Minn., Wis., Dak.	364	355	360	442	81.5	257	28	113	9
Okla., Kan., Mo.	841	624	715	786	91.0	456	33	224	5
Dist. 2 total	**3,357**	**3,079**	**3,221**	**3,583**	**89.9**	**1,900**	**221**	**913**	**62**
Inland Texas	930	857	618	647	95.5	491	33	174	6
Texas Gulf Coast	3,680	3,107	3,197	4,031	79.3	1,473	286	934	170
La. Gulf Coast	3,341	3,119	3,199	3,264	98.0	1,301	378	820	152
N. La. and Ark.	217	172	182	215	84.7	98	6	45	10
New Mexico	144	96	96	113	85.0	111	0	32	0
Dist. 3 total	**8,312**	**7,081**	**7,292**	**8,270**	**88.2**	**3,474**	**703**	**2,005**	**338**
Dist. 4 total	**605**	**513**	**515**	**596**	**86.4**	**307**	**26**	**163**	**13**
Dist. 5 total	**2,697**	**2,379**	**2,470**	**3,173**	**77.8**	**1,680**	**436**	**518**	**138**
Feb. 9, 2007	**18,188**	**14,492**	**14,940**	**17,335**	**86.2**	**9,012**	**1,474**	**4,108**	**680**
Feb. 2, 2007*	**18,624**	**14,612**	**14,984**	**17,335**	**86.4**	**8,815**	**1,443**	**3,928**	**566**
Feb. 10, 2006	**16,587**	**14,522**	**15,073**	**17,115**	**88.1**	**8,305**	**1,472**	**3,781**	**621**

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

OGJ GASOLINE PRICES

	Price ex tax 2-7-07	Pump price* 2-7-07	Pump price 2-8-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	177.6	217.3	232.7
Baltimore	178.0	219.9	237.6
Boston	177.4	219.3	234.6
Buffalo	180.2	240.3	253.8
Miami	184.4	234.7	246.2
Newark	179.4	212.3	244.4
New York	167.3	227.4	255.6
Norfolk	173.0	210.6	227.0
Philadelphia	191.9	242.6	245.4
Pittsburgh	173.2	223.9	246.2
Wash., DC	190.5	228.9	248.2
PAD I avg.	179.3	225.2	242.9
Chicago	191.0	241.9	252.5
Cleveland	175.5	221.9	228.4
Des Moines	171.9	212.3	221.5
Detroit	169.8	219.0	231.8
Indianapolis	177.7	222.7	224.7
Kansas City	170.9	206.9	217.7
Louisville	186.1	223.0	223.2
Memphis	168.8	208.6	226.9
Milwaukee	176.3	227.6	235.2
Minn.-St. Paul	177.9	218.3	222.9
Oklahoma City	170.2	205.6	214.5
Omaha	172.9	219.3	223.9
St. Louis	176.3	212.3	224.6
Tulsa	169.9	205.3	217.8
Wichita	167.9	211.3	216.6
PAD II avg.	174.9	217.1	225.5
Albuquerque	177.5	213.9	231.4
Birmingham	174.2	212.9	226.7
Dallas-Fort Worth	177.2	215.6	228.2
Houston	171.1	209.5	224.5
Little Rock	173.4	213.6	228.3
New Orleans	174.9	213.3	237.8
San Antonio	168.5	206.9	223.0
PAD III avg.	173.8	212.3	228.6
Cheyenne	172.5	204.9	213.5
Denver	171.8	212.2	219.5
Salt Lake City	172.3	215.2	220.7
PAD IV avg.	172.2	210.8	217.9
Los Angeles	202.1	260.6	254.6
Phoenix	191.8	229.2	234.2
Portland	209.3	252.6	213.6
San Diego	210.4	268.9	252.0
San Francisco	225.6	284.1	252.0
Seattle	208.3	260.7	234.6
PAD V avg.	207.9	259.4	240.2
Week's avg.	**180.4**	**224.0**	**232.1**
Jan. avg.	**181.7**	**225.3**	**227.3**
Dec. avg.	**184.9**	**228.5**	**216.5**
2007 to date	**181.5**	**225.1**	—
2006 to date	**186.4**	**228.8**	—

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

REFINED PRODUCT PRICES

	2-2-07 ¢/gal		2-2-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	152.98	New York Harbor	168.26
Gulf Coast	150.85	Gulf Coast	164.51
Los Angeles	179.35	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	141.36	ARA	166.49
Singapore	155.24	Singapore	169.17
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	152.48	New York Harbor	94.95
Gulf Coast	150.60	Gulf Coast	100.60
Los Angeles	187.35	Los Angeles	128.15
		ARA	84.24
		Singapore	112.97

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

BAKER HUGHES RIG COUNT

	2-9-07	2-10-06
Alabama	3	6
Alaska	9	10
Arkansas	38	18
California	32	33
Land	29	30
Offshore	3	3
Colorado	93	82
Florida	0	1
Illinois	0	0
Indiana	1	0
Kansas	11	7
Kentucky	9	6
Louisiana	188	176
N. Land	52	56
S. Inland waters	24	19
S. Land	43	38
Offshore	69	63
Maryland	0	0
Michigan	0	1
Mississippi	19	6
Montana	20	23
Nebraska	0	0
New Mexico	85	95
New York	9	4
North Dakota	32	28
Ohio	13	9
Oklahoma	183	173
Pennsylvania	13	16
South Dakota	0	0
Texas	822	683
Offshore	11	11
Inland waters	2	1
Dist. 1	24	21
Dist. 2	31	28
Dist. 3	53	56
Dist. 4	93	80
Dist. 5	153	121
Dist. 6	135	95
Dist. 7B	36	28
Dist. 7C	47	37
Dist. 8	107	75
Dist. 8A	25	38
Dist. 9	40	28
Dist. 10	65	64
Utah	44	31
West Virginia	27	25
Wyoming	71	96
Others—ID-1; TN-5; VA-3	9	3
Total US	**1,731**	**1,532**
Total Canada	**641**	**714**
Grand total	**2,372**	**2,246**
Oil rigs	254	206
Gas rigs	1,473	1,323
Total offshore	83	78
Total cum. avg. YTD	**1,717**	**1,489**

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

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

SMITH RIG COUNT

Proposed depth, ft	2-9-07 Rig count	2-9-07 Percent footage*	2-10-06 Rig count	2-10-06 Percent footage*
0-2,500	47	—	40	2.5
2,501-5,000	96	55.2	98	43.8
5,001-7,500	219	22.8	206	16.9
7,501-10,000	421	3.5	337	4.1
10,001-12,500	406	2.2	325	1.2
12,501-15,000	272	0.3	303	0.3
15,001-17,500	123	1.6	121	0.8
17,501-20,000	77	—	59	—
20,001-over	39	—	23	—
Total	**1,700**	**7.6**	**1,512**	**6.5**
INLAND	37		39	
LAND	1,599		1,416	
OFFSHORE	64		57	

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

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

OGJ PRODUCTION REPORT

	[1]2-9-07	[2]2-10-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	790	827
California	693	692
Colorado	58	60
Florida	7	6
Illinois	31	29
Kansas	94	96
Louisiana	1,373	1,170
Michigan	14	15
Mississippi	52	47
Montana	92	97
New Mexico	163	160
North Dakota	99	101
Oklahoma	171	172
Texas	1,380	1,291
Utah	44	46
Wyoming	141	140
All others	64	69
Total	**5,284**	**5,039**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	2-9-07
Alaska-North Slope 27°	49.99
South Louisiana Sweet	60.75
California-Kern River 13°	48.55
Lost Hills 30°	56.50
Southwest Wyoming Sweet	56.14
East Texas Sweet	58.02
West Texas Sour 34°	47.75
West Texas Intermediate	56.50
Oklahoma Sweet	56.50
Texas Upper Gulf Coast	53.25
Michigan Sour	49.50
Kansas Common	55.50
North Dakota Sweet	50.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	2-2-07
United Kingdom-Brent 38°	55.70
Russia-Urals 32°	52.60
Saudi Light 34°	49.55
Dubai Fateh 32°	52.55
Algeria Saharan 44°	57.02
Nigeria-Bonny Light 37°	57.64
Indonesia-Minas 34°	54.98
Venezuela-Tia Juana Light 31°	51.09
Mexico-Isthmus 33°	50.98
OPEC basket	53.40
Total OPEC[2]	51.81
Total non-OPEC[2]	52.49
Total world[2]	52.11
US imports[3]	49.35

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

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

US NATURAL GAS STORAGE[1]

	2-2-07	1-26-07	Change
	Bcf		
Producing region	744	807	–63
Consuming region east	1,326	1,465	–139
Consuming region west	277	299	–22
Total US	**2,347**	**2,571**	**–224**
	Nov. 06	**Nov. 05**	**Change, %**
Total US[2]	**3,407**	**3,189**	**6.8**

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

Statistics

International rig count

Region	Jan. 2007 Land	Jan. 2007 Off.	Jan. 2007 Total	Jan. 06 Total
WESTERN HEMISPHERE				
Argentina	85	—	85	80
Bolivia	2	—	2	5
Brazil	16	20	36	34
Canada	565	4	569	660
Chile	1	—	1	—
Colombia	24	—	24	18
Ecuador	12	—	12	12
Mexico	57	27	84	92
Peru	8	1	9	3
Trinidad	3	4	7	3
United States	1,630	84	1,714	1,473
Venezuela	55	18	73	75
Other	2	—	2	1
Subtotal	**2,460**	**158**	**2,618**	**2,456**
ASIA-PACIFIC				
Australia	10	11	21	14
Brunei	1	3	4	4
China-offshore	—	18	18	17
India	54	32	86	82
Indonesia	33	16	49	60
Japan	1	—	1	3
Malaysia	—	14	14	14
Myanmar	8	3	11	10
New Zealand	2	2	4	7
Papua New Guinea	2	—	2	3
Philippines	1	—	1	2
Taiwan	—	—	—	—
Thailand	3	9	12	10
Vietnam	—	4	4	11
Other	3	1	4	7
Subtotal	**118**	**113**	**231**	**244**
AFRICA				
Algeria	24	—	24	21
Angola	3	2	5	3
Congo	1	2	3	—
Gabon	4	—	4	1
Kenya	—	—	—	—
Libya	12	1	13	9
Nigeria	3	6	9	9
South Africa	—	—	—	—
Tunisia	3	2	5	1
Other	2	4	6	3
Subtotal	**52**	**17**	**69**	**47**
MIDDLE EAST				
Abu Dhabi	9	5	14	14
Dubai	1	—	1	3
Egypt	35	9	44	32
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	1	—	1	1
Kuwait	16	—	16	11
Oman	40	—	40	34
Pakistan	20	—	20	14
Qatar	1	8	9	13
Saudi Arabia	72	6	78	50
Sudan	—	—	—	—
Syria	24	—	24	22
Yemen	15	—	15	14
Other	1	—	1	2
Subtotal	**235**	**28**	**263**	**210**
EUROPE				
Croatia	1	—	1	3
Denmark	—	5	5	3
France	1	—	1	—
Germany	5	—	5	3
Hungary	3	—	3	4
Italy	3	—	3	4
Netherlands	1	4	5	5
Norway	—	16	16	19
Poland	2	—	2	2
Romania	2	—	2	2
Turkey	4	—	4	4
UK	1	23	24	27
Other	3	—	3	5
Subtotal	**26**	**48**	**74**	**81**
Total	**2,891**	**364**	**3,255**	**3,038**

Definitions, see OGJ Sept. 18, 2006, p. 42
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	258	2.17
Caribbean	Houston	Resid.	380	182	1.71
Caribbean	Houston	Resid.	500	162	1.52
N. Europe	New York	Dist.	200	246	3.29
N. Europe	Houston	Crude	400	196	3.84
W. Africa	Houston	Crude	910	133	2.89
Persian Gulf	Houston	Crude	1,900	57	2.30
W. Africa	N. Europe	Crude	910	135	2.17
Persian Gulf	N. Europe	Crude	1,900	58	1.71
Persian Gulf	Japan	Crude	1,750	61	1.46

*January 2007 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

US LNG imports

Country	Nov. 2006	Oct. 2006	Nov. 2005	Change from a year ago, %
	MMcf			
Algeria	—	—	8,954	—
Brunei	—	—	—	—
Malaysia	—	—	—	—
Nigeria	5,732	8,957	—	—
Oman	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	24,583	24,677	30,077	–18.3
Others	16,921	2,551	18,946	–10.7
Total	**47,236**	**36,185**	**57,977**	**–18.5**

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

Baker oil tools workover rig count*

Region	Jan. 2007	Jan. 2006	Change, %
Gulf Coast	270	298	–9.4
Midcontinent	274	255	7.5
Northeastern	74	79	–6.3
Rocky Mountains	213	228	–6.6
Southeastern	181	212	–14.6
West Texas	331	306	8.2
Western	136	128	6.3
Total US	**1,479**	**1,506**	**–1.8**
Canada	799	812	–1.6
Total N. America	**2,278**	**2,318**	**–1.7**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 18, 2006, p. 42. Source: Baker Hughes Inc. Data available in OGJ Online Research Center.

Propane prices

	Dec. 2006	Jan. 2007	Dec. 2005	Jan. 2006
	¢/gal			
Mont Belvieu	96.63	89.35	105.58	98.86
Conway	94.42	86.96	107.98	96.72
Northwest Europe	98.81	92.58	114.74	119.68

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
January 2007						
Product revenues	64.27	60.75	62.37	72.81	61.16	60.57
Feedstock costs	–52.79	–55.31	–50.08	–48.32	–51.92	–55.27
Gross margin	11.48	5.44	12.29	24.49	9.24	5.30
Fixed costs	–2.03	–2.35	–2.29	–2.67	–2.29	–1.78
Variable costs	–1.88	–1.29	–1.67	–2.85	1.79	–0.73
Cash operating margin	**7.57**	**1.80**	**8.33**	**18.97**	**5.16**	**2.79**
December 2006	7.19	2.14	8.32	17.48	3.79	–0.12
YTD avg.	7.57	8.33	1.80	18.97	5.16	2.79
2006 avg.	12.49	15.00	6.01	23.72	5.77	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

December 2006	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	237.29	219.35	253.19	242.96
Taxes	52.51	38.40	56.11	48.83
Wholesale price	173.46	171.61	193.22	184.10
Spot price	161.07	164.55	183.48	171.77
Retail margin	7.89	9.34	3.86	10.03
Wholesale margin	12.39	7.06	9.74	12.33
Gross marketing margin	**20.28**	**16.40**	**13.60**	**22.36**
November 2006	17.38	6.97	8.24	17.38
YTD avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38
2003 avg.	22.69	19.10	30.89	31.42

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Effective April 2003, Los Angeles margins include ethanol blending.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
January 2007			
Product revenues	49.44	79.84	93.53
Feedstock costs	–22.91	–50.91	–76.80
Gross margin	26.53	28.93	16.73
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–4.50	–5.28	–7.07
Cash operating margin	**16.65**	**17.29**	**2.47**
December 2006	12.89	15.68	–3.36
YTD avg.	16.65	17.29	2.47
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

January 2007	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	6.12	5.46
Liquids	0.93	2.55
Gas purchase cost	6.81	7.33
Operating costs	0.07	0.15
Cash operating margin	**0.18**	**0.53**
December 2006	0.15	0.58
YTD avg.	0.18	0.53
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment % of liquids	78%	77%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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Fossil fuel days are over, Turner informs Houston

When an oil company executive comments on energy trends, television people discount the observations on the basis of vested interest.

A television executive, however, lugs around no such baggage.

So when CNN founder Ted Turner shows up in Houston to opine about energy and the environment, people should take note. Right?

The Editor's Perspective

by Bob Tippee, Editor

"The days of fossil fuels as a fuel are over," Turner told the Houston World Affairs Council Feb. 7 while voicing fear about global warming. "It's just a matter of how soon everybody recognizes it. We only have one atmosphere."

Only one atmosphere! Who could have known?

But there it was, straight from a billionaire with insight unencumbered by connection with anything as nasty as oil and gas. He must be right.

In response to Turner's revelation about the death of fossil fuels, however, Houston didn't act eager to abandon its role as an oil and gas center.

A quick check indicated that rigs were still drilling in the Gulf of Mexico and around Texas. Refineries stayed busy along the coast. Tankers plied the Ship Channel pretty much as usual.

It must reflect failure by the witless to recognize what Turner—he's a television guy, after all—finds obvious: fossil fuels, 85% of the world's energy supply—kaput!

And forget war. Forget AIDS. Forget 2 billion human beings living in poverty.

"I think dealing with climate change is going to be the biggest single challenge humanity has ever faced, and we're facing it now," he proclaimed.

Remember: Turner's not an oil guy. When he speaks of doom, every word is worth its weight in ethanol.

In fact, Turner's better than not an oil guy; he's a solar guy. He told reporters in Houston that he recently invested millions of dollars in a New Jersey solar energy company.

No vested interest there. It's solar. It's righteous.

Predicting that clean, renewable future "is going to make a fortune," Turner praised wind, too.

So extend the logic. Millions of windmills, spinning furiously...and...and cutting the atmosphere into two pieces so there's a spare on hand when one overheats!

Somebody call Congress.

(Online Feb. 9, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude challenges $60/bbl ceiling

The March contract for benchmark US light, sweet crudes jumped to $59.89/bbl Feb. 9, the highest front-month crude closing on the New York Mercantile Exchange since late December, as a frigid cold front embraced the eastern US and a pipeline fire shut in 95% of production at Elk Hills oil and gas field near Bakersfield, Calif.

"Crude's up tick since the start of the year has met firm resistance at $60/bbl," said analysts at Raymond James & Associates Inc. "The fundamentals underlying the oil market support such a move, although there will likely be profit-taking and short-covering since prices have shot up about $9/bbl in the last 3 weeks, a result of continuing cold weather and added geopolitical risk. Iranian leader Ayatollah Ali Khamenei cautioned about challenging [his country's] nuclear program as further pressure could provoke antagonistic targeting of US interests worldwide."

Meanwhile, Nigeria oil workers contemplated a strike because of rebel attacks and kidnappings in the Niger Delta oil-producing region. "Technically, the strength of [the Feb. 8] closing rally has thrown crude oil back into positive momentum," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland.

A Feb. 6 fire at Elk Hills shut in most of the field's production of 120,000 b/d of oil equivalent. It is the largest natural gas field in California, Raymond James reported, but its production is 60% liquids. Occidental Petroleum Corp., operator, declared force majeure, suspending contractual deliveries from that field. No timeframe was given for returning the field to production.

The Energy Information Administration said US crude inventories slipped by 400,000 bbl to 324.5 million bbl in the week ended Feb. 2. US gasoline stocks increased 2.6 million bbl to 227.2 million bbl, while distillate fuel inventories declined by 3.7 million bbl to 136.3 million bbl, with decreases in both heating oil and diesel. "For the first time in a while, the latest US weekly data have demand indications that are pretty good across the board," said Paul Horsnel, Barclays Capital Inc., London. "Heating oil inventories have fallen for a third week, bringing them closer to their 5-year average." EIA reported the withdrawal of 224 bcf of natural gas from US underground storage. US gas storage was at 2.3 tcf, finally dropping below year-ago levels by 26 bcf but still above the 5-year average by 378 bcf.

Golden corn

High energy prices have attracted media attention for many months, but corn prices also are at record high levels on the Chicago Board of Trade, hovering around $4/bushel since December, well above the average price of $2.40/bushel over the last 10 years.

"This current price rally is based on expectations for the coming ethanol production boom to stretch corn demand beyond US farmers' ability to supply, which is a more enduring price driver," said Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va. Corn prices escalated more than 70% in 2006, primarily because of increased demand for ethanol. Commodity Futures Trading Commission data show the rise in corn prices also coincides with a substantial increase in noncommercial net long positions.

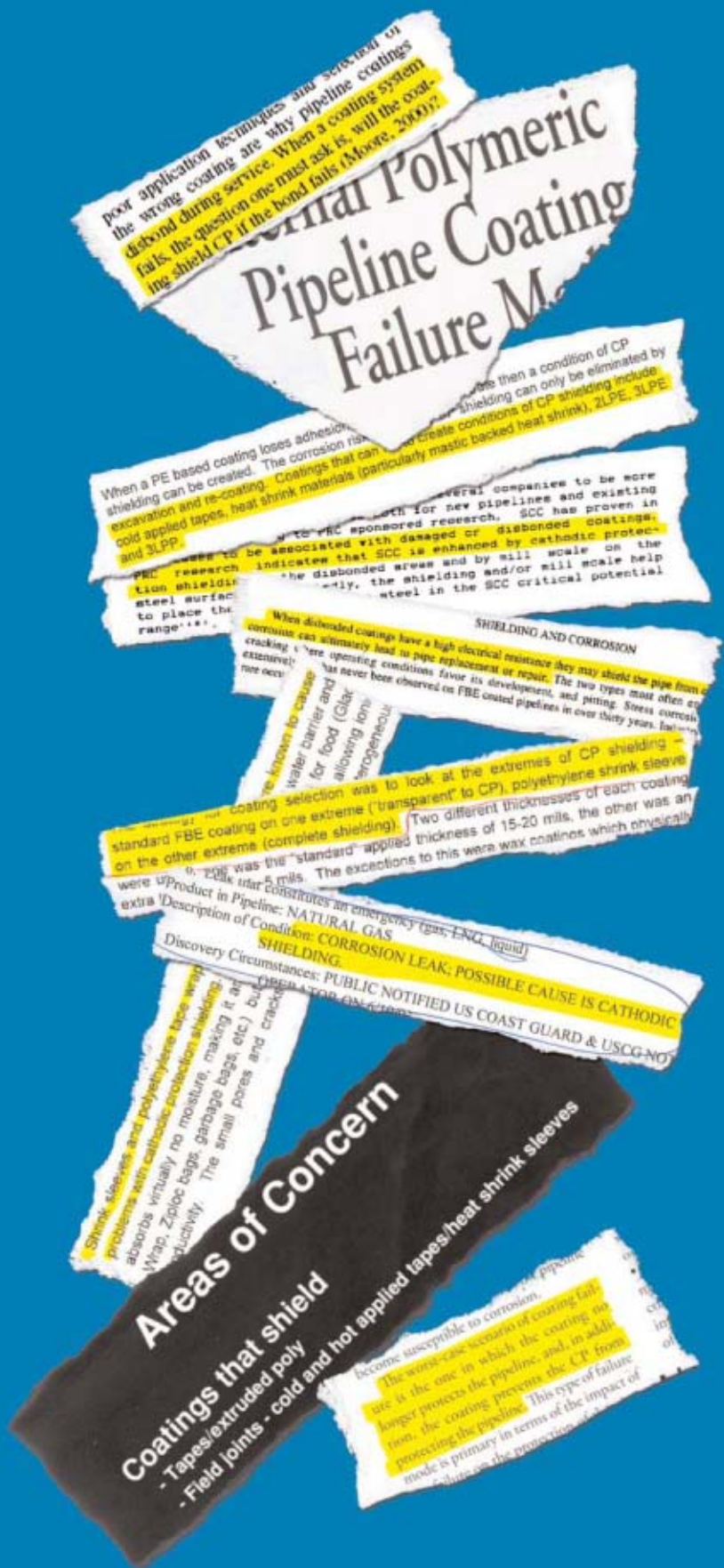
With the market price for corn escalating, US farmers planted 78 million acres with corn last year. In Midwest farms and markets, there is speculation that an additional 6-12 million acres of corn will be planted in 2007, "with recent surveys at the top of the range," Rousseau said in a Feb. 7 report.

"An extra 10 million acres coming into corn in 2007 and a 159 million bushel/acre average yield suggests a record 12.6 billion bushel harvest and increased season-ending corn inventories," said Rousseau. "Our model assumes a 4 billion gal year-over-year increase in ethanol production from September 2007-August 2008, representing a 1.5 billion bushel increase in corn demand."

The lure of an El Dorado of corn and ethanol has many US farmers demanding to pull idle farmland out of government conservation programs to cash in on this golden opportunity. As a result, the US Agriculture Department is considering releasing acreage from its Conservation Reserve Program in order to produce more corn for ethanol. That program pays farmers to idle environmentally sensitive low-producing land. A decision is expected by early summer, but the acreage wouldn't go into production until 2008, officials said.

Meanwhile, Rousseau warned, "A number of these ethanol projects have yet to begin construction and could be delayed or canceled. Although corn futures prices are currently well above our forecasts, we believe it is important to understand the context and that prices could reverse as quickly as they rose."

(Online Feb. 12, 2007; author's e-mail: samf@ogjonline.com)



"Shielding: Preventing or diverting the cathodic protection current from its intended path"

NACE Standard RP0169-2002, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems"

"Materials and construction practices that create electrical shielding should not be used on the pipeline"

NACE Standard RPO169-2002, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems

"Coating material for external corrosion control under § 195.557 must...Support any supplemental cathodic protection"

49 CFR Ch. 1 (10-1-04 Edition, p. 198.)

Evidence of CP shielding problems grows stronger every month. In October 2006 alone, no less than five articles[1] discussing cathodic shielding problems appeared in pipeline technical trade publications.

Solid film back coatings such as shrink sleeves, 3 layer systems, and tapes are proven to shield.

Several other types of corrosion coatings "may or may not" shield.

Only FBE and Polyguard RD-6 are proven not to shield when adequate CP is available.

Non-shielding coatings such as RD-6 are often called *"Fail/safe"*. Fail/safe coatings, in the event of failure (disbondment) are designed to permit protective CP currents to reach water in the disbonded area.

So, since the use of corrosion coatings that shield CP is contrary to NACE RP0169-2002, and is contrary to DOT regulations as published in 49CFR§195.557, the question is:

"Does your organization require that coatings be CP compatible when disbondments occur?"

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2. Talk to operators who have used Polyguard's RD-6 system. *(There are many)*. Ask them if they know of any serious corrosion or SCC ever found under RD-6. *(We don't, even after 19 years)*
3. Have someone in your organization attend the NACE course "Coatings in Conjunction with Cathodic Protection".

Polyguard RD-6. Fail /Safe. A 19 years track record. It's time for some serious advertising. Check us out.

(1) A list of the five October 2006 articles about shielding are on the Polyguard website.

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Supplement to *Oil & Gas Journal* • February 19, 2007

Technology Forum

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OIL&GAS JOURNAL PennWell

Technology Forum

Pipeline Equipment and Services

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Pipeline integrity concerns pressuring industry to zero-fault mode

Growing concerns over national security, environmental and human safety, and energy supply reliability are stepping up the pressure on the pipeline industry to strive for a zero-fault standard for pipeline integrity.

At the same time, the industry must contend with ever-growing demand for oil and natural gas, an aging global pipeline infrastructure, a shortfall of skilled talent, and rising costs.

The convergence of these factors have created an extremely challenging environment for industry to formulate new strategies and to develop new technologies to ensure the integrity of existing and future pipelines.

Pipeline integrity philosophy

Ensuring pipeline integrity is about more than just searching for technology solutions—it's about adhering to a philosophy of sticking to the basics, said Phillip Morrison, vice-president, pipeline integrity products and services, T.D. Williamson Inc. (TDW), Tulsa.

"If you take a close look at the history of TDW, you will clearly see that we are a long-term leader in the development of pipeline maintenance technology, which of course includes tools, products, and service techniques. Many of the most dependable technologies in use worldwide were first developed by our engineers," he said.

"TDW believes in the pursuit and refinement of technolo-

Pipeline integrity becomes an increasingly important issue with the dramatic expansion of facilities around the world. Here, workers connect line pipe in Salym oil field near Salym, Russia. *Photo courtesy of Shell Photographic Services, Shell International Ltd.*

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Solving problems, reducing costs

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"Technology has its place, and that place is within a conscientiously applied maintenance program. There are no shortcuts to heading off integrity issues. Stick to the basics, and the need for exotic technologies and their related costs are held to a minimum."

—*Phillip Morrison , T.D. Williamson Inc.*

gies that have the ability to provide a clearer analysis of pipeline anomalies. We also place great value in the development of methods that allow maintenance tasks to be performed faster and more efficiently.

"We are constantly in the process of making our existing products and services more efficient, economical, and safe to use. In fact, it is a rare day that our legal department isn't ushering at least a handful of new or improved equipment through the patent approval process. We are believers in the blessings of technology. However, after many decades of hands-on, practical, in-the-field experience, TDW has gained a very clear understanding of the role technology plays in maintaining a dependable level of pipeline integrity."

Morrison thinks that pipeline owners or operators that are waiting for a "silver bullet" technology that will simply and easily solve all pipeline integrity issues need to realize that it just doesn't exist.

"Technology has its place, and that place is within a conscientiously applied maintenance program. There are no shortcuts to heading off integrity issues."

Morrison contends that the pipeline operators with the fewest integrity situations to deal with typically are those who are good at sticking to the basics, namely regular cleaning, inspection, and corrosion control measures.

"Stick to the basics, and the need for exotic technologies and their related costs are held to a minimum," he said.

Morrison stressed that every pipeline is different: "The internal and external environment of a pipeline will fairly well dictate many of its maintenance requirements. Maintenance solutions that sustain pipeline integrity are always going to be a combination of technologies that are 'tuned' to a pipeline's characteristics. Pipeline owner and service company personnel need to work together as an integral team to provide ongoing integrity management."

Innovations

Even with an emphasis on sticking to the basics, Morrison acknowledged that new and developing technologies that have the potential to contribute to the future of pipeline integrity need to be encouraged.

"However, innovation is not limited to new technology," he said. "Innovation will have occurred when greater system integrity and capacity occurs at a lower overall cost to the industry and is accomplished in less time than present methodologies, programs, and practices allow."

Morrison contends that industry already has found and defined the problems and has produced technologies to fix those problems, but to achieve improved pipeline integrity, industry's tactics should shift to doing its best to keep problems from recurring.

"The primary focus of the industry should be on establishing and sustaining preventative maintenance programs," he said. "Achieving key pipeline integrity and performance objectives is, in large part, dependent on having a clean pipe. Assuring the cleanliness and piggability of pipelines may provide the most significant contribution to pipeline integrity globally."

Innovative ways to manage information and data are crucial for comprehensively addressing the issue of pipeline integriaty, according to David Edgar, vice-president of the pipeline business unit of Mustang Engineering LP, Houston.

"Pipeline integrity management is predicated on divergent technologies individually performing unique functions—but [at the same time] collectively assessing pipelines without disregarding one area or another. Because of this comprehensive approach, the list [of innovations] could be expanded to include other technologies such as information and database management."

Environmental concerns

The biggest challenge still facing the pipeline industry is how to prevent leaks and spills that can harm the environment and the public, noted Essam Zaghloul, president and CEO of FOX-TEK Inc., Toronto.

"Keeping the oil flowing is essential for the industry, but

"The process to obtain...approvals [for integrity digs] can sometimes take a substantial amount of time. This process has to be reviewed and changed to allow pipeline companies early entry for the integrity digs and follow-up with the agencies with an after-the-fact permit."

—*David Edgar, Mustang Engineering LP*

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doing so with safe operating practices in order to maintain safe facilities is essential to protecting the environment," he said.

At the same time, the pipeline industry must cope with an often cumbersome regulatory and permitting regime even in its efforts to ensure pipeline integrity.

"Currently, when a pipeline is tested either by hydrotest or smart tool, there is always the challenge of visual inspection and repair. If the area of concern falls within a wetland, state or federal lands, or [has] other ecological significant properties, then a permit is required by one or more agencies that have jurisdiction over these types of properties," Edgar pointed out. "The process to obtain these approvals can sometimes take a substantial amount of time. This process has to be reviewed and changed to allow pipeline companies early entry for the integrity digs and follow-up with the agencies with an after-the-fact permit."

Another big environmental challenge for the pipeline industry is an indirect challenge, Edgar added: transporting low-sulfur diesel and maintaining its low-sulfur content without contaminating the product.

Simply increasing public awareness of how excavation often damages pipelines may be the most effective simple solution to preventing environmental damage by pipelines.

"The greatest cause of large releases is third-party damage," Edgar said. "To minimize this, we need to increase public education programs."

Morrison concurred: "Every hour of every day, someone somewhere is damaging a pipeline. This cannot be allowed to continue. We need increased awareness, improved vigilance, and the technology to detect damage when it occurs."

Edgar noted that the industry is inching closer to having a national "811" number for excavators to call before excavating.

"This system will decrease third-party damages because it will be easier to remember and use," he said. "Hopefully, having a national 811 system will also result in having nationally consistent rules and regulations concerning the requirement to call before you dig."

New challenges

Posing new challenges for the industry is the fact that pipeline integrity issues are now moving into systems that have not been regulated in the past, Morrison pointed out. "For the most part, these systems are not compatible with technologies used today on larger, longer, and straighter lines. It may soon become evident that creating regulations for these difficult lines is the easy part and proving them safe will be difficult."

Another area of concern is aging pipelines, he added.

"An entire worldwide generation of pipelines has now become a seriously aged infrastructure. Our current global system for producing and transporting natural gas and hazardous liquids may become unable to deliver the energy needed within the next 10 years.

"Owner company and service company personnel changes over the years have caused a significant loss of corporate memory about each pipeline and how it was built, how it operates, what could be wrong with it, and what could be done to make it better.

"We need to attempt to stop such a tremendous loss of memory and try to preserve this vital information to assure future pipeline performance. The answer could be a focused program established to collect, verify, and maintain essential data on every pipeline.

"Once assimilated, this valuable information can be permanently archived, updated, and passed along if ownership or operational management should change."]

Pipeline challenges magnified in arctic, deepwater conditions

The difficulties entailed in pipeline installation, operation, and maintenance are magnified dramatically in the challenging physical and geographical conditions that deepwater and arctic operations present.

Compounding the challenge of technological solutions to accommodate such conditions is the charge that pipeline operators and contractors carry in these areas, in that they are also environmentally sensitive.

Deepwater challenges

Ultradeepwater pipelaying is clearly a challenge, with water depths of 3,000 m being targeted for some development, noted Allen Leatt, chief technology office for Acergy SA (formerly Stolt Offshore), Sunbury-on-Thames, England.

"At this depth, very large lay tensions are required, resulting in high-specification installation vessels and equipment," he said. "To meet these challenges Acergy invested in a new 750-ton tension J-lay tower for the Acergy Polaris [derrick lay barge]. The tower is now installed and operational on the BP Greater Plutonio project [off Angola]."

Leatt contends that the environmental impact of pipeline trenching and burial may present future challenges for the in-

An industry standard for offshore pipeline risk assessment, where failure frequencies are data-based, "would increase opportunities for evaluation among multiple disciplines and improve decision-making for pipeline integrity. An industrywide knowledge base also would allow designers to focus on mission-critical elements for effective integrity management."

— *John Stearns, INTEC Engineering*

dustry: "Minimizing seabed disturbance and turbidity presents challenges to today's burial techniques."

Other hurdles loom in deepwater pipeline installation as distances from seabed to production facilities lengthen with more ambitious projects.

"For the deepwater market today, pipelines remain relatively short," Leatt said. "However, this is changing with the innovation of Low Dosage Hydrate Inhibitors now enabling longer tiebacks. As these lines become more sophisticated (clad lines, heavily insulated lines, or HDPE water injection lines), onshore fabrication will become more cost-effective."

Leatt also sees innovations in pipeline insulation characteristics—either active, via electrical heating, or passive, via improved coatings—making a crucial difference to offshore pipelay operations.

"Their ability to minimize the requirement for pipe-in-pipe solutions and heavily insulated lines, with their corresponding high installation tensions, will result in improved project pipelaying economics," he said.

For large offshore trunklines, the ability to monitor and record the amount of fatigue every single joint experiences during installation ensures that the as-built documentation represents the material state of the pipeline following installation, Leatt said.

"Acergy conducted such measurement during the installation of the Langeled Pipeline [in the Norwegian North Sea] from the Acergy Piper [lay barge]. For the total installation of 900 km, the individual fatigue of every single joint was delivered to the operator as part of the design, fabrication, and installation dossier."

New standards needed

Standardizing information about the world's offshore pipelines would go a long way toward aiding pipeline operators and contractors working on the growing global deepwater infrastructure, according to John Stearns, vice-president, marine pipeline systems, INTEC Engineering, Houston. INTEC is a division of the Heerema Group.

Broader use of geographic information systems (GIS) databases to store and retrieve information throughout a project's life cycle would be especially beneficial to deepwater development.

"GIS previously has been the domain of onshore pipelines," Stearns noted. INTEC's vision is to make GIS database an industry standard. The database would contain all design information, material quality assessment/quality control [QA/QC] information, fabrication QA/QC information, and installation QA/QC information, as well as inspection, maintenance, and repair information."

Stearns would also like to see an industry standard for offshore pipeline risk assessment, where failure frequencies are data-based.

This "would increase opportunities for evaluation among multiple disciplines and improve decision-making for pipeline integrity. An industrywide knowledge base also would allow designers to focus on mission-critical elements for effective integrity management."

Pipeline construction and operation is occurring in ever more challenging environments. A landmark project in the annals of pipeline construction in challenging environments was the Trans-Alaska Pipeline System, shown here. *Photo courtesy of BP PLC.*

"The remoteness of operation and environment present many challenges for equipment, vessels, and logistics. Lessons learned from remote operations in West Africa, the harsh and challenging environment of the North Sea, together with investing in the right equipment and vessels, will enable the successful development of these regions."

— Allen Leatt, Acergy SA

Technology innovations

More research and development is needed in certain technology areas to improve assurance of pipeline integrity in challenging environments, according to Stearns.

"In the near term, industry R&D should focus on expanding the ability of MFL [magnetic flux leakage] inspection tools to inspect thick-wall pipes," he said. "Industry also requires new techniques, adapted and commercially viable, to assess the integrity of multidiameter pipelines and to detect fatigue cracks at high-fatigue locations in pipelines and risers, including both parent metal and weld areas.

Other areas where R&D could improve pipeline system integrity, said Stearns, without adding significant costs or that could improve project economics while maintaining or enhancing pipeline integrity, are:

- Development of higher-integrity, watertight, field joint coating systems for use in fatigue-loading situations. "Industry could then use less-stringent in-air crack growth rates for the fatigue design, compared with accepting the penalty of crack-growth rates in seawater with cathodic protection."
- Improvements in automated ultrasonic inspection for internally clad steel risers.
- Improved understanding of fatigue performance of corrosion resistant steel for catenary risers.

- Welding of ultrahigh-strength pipelines.
- Improved understanding of fatigue damage to offshore girth welds from low stresses in the loading spectrum.

Arctic realms

Leatt also pointed to arctic frontier areas such as the Barents Sea that present significant environmental challenges for contractors.

"As an EPIC [engineering, procurement, installation, and construction] contractor, Acergy recognizes that we occupy a critical position, even if limited in time, in the lifecycle of a pipeline," he said. "The remoteness of operation and environment presents many challenges for equipment, vessels, and logistics. Lessons learned from remote operations in West Africa, the harsh and challenging environment of the North Sea, together with investing in the right equipment and vessels, will enable the successful development of these regions."

Apart from new deepwater and arctic challenges, Leatt also expressed concern over the state of the world's existing offshore pipeline infrastructure.

"As offshore basins mature, the corresponding infrastructure is aging," he noted. "As with any maturing asset, the operational expenditure required to effectively maintain the system increases, while the production curve of the asset decreases.

"Through effective integrity management systems, the pipeline owner effectively manages the environmental risks. Key to this will be the inspection, maintenance, and repair programs put in place to ensure proactive management of the pipeline."

The final environmental challenge for the pipeline owners will be the decommissioning of pipelines, he added.]

Monitoring, inspection focus of next game-changing technology

Pipeline operators and contractors are focusing much of their attention on potentially game-changing technologies in the areas of continuous monitoring and inspection.

To some extent, they may focusing too much on detection solutions, contends David Edgar, vice-president of the pipeline business unit of Mustang Engineering LP, Houston.

> "I believe that everyone is concentrating too much on detection and not prevention. Of the possibilities listed, the only one that prevents failures is cathodic protection."
>
> —David Edgar, Mustang Engineering LP

"I believe that everyone is concentrating too much on detection and not prevention," he said. "Of the possibilities listed, the only one that prevents failures is cathodic protection."

On the other hand, cathodic protection isn't a magic bullet for ensuring pipeline integrity, according to Essam Zaghloul, president and CEO of FOX-TEK Inc., Toronto.

"Cathodic protection is a trusted method of preventing corrosion, but there are always those exceptional areas where the CP system is not working perfectly," he pointed out. "In addition, because the CP system does not measure the changes in the pipe, there is no direct way to see if it is working effectively."

Edgar maintains that if the threat assessment has determined that the largest threat is external, the pipeline is not able to pass a smart tool and cannot be taken out of service: "I would look at a direct assessment program coupled with good cathodic protection."

In-line inspection technologies

Today, the most significant contribution to pipeline integrity is being made by new technologies that operators can use to improve their continuous monitoring capabilities, Zaghloul contends.

[In-line inspection] is also a trusted tool, but the high cost of running these tools prohibits their use to once every 5-7 years," he said. "A lot of changes in product and operating conditions can happen to a pipe in that time that may result in increased corrosion rates. To a lesser degree, the improvements in ILI technology between runs sometimes makes the comparison of data difficult. Leak detection is important, but it is a 'reactive' approach. A proactive method that finds or tracks problems before a leak occurs would be much more valuable."

Edgar allows that ILI is a good tool with the potential to be a great tool.

"However, ILI is still not where it needs to be to identify some of the greatest concerns like SCC [stress corrosion

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cracking], seam defects, and cracks," he said. "ILI can reliably detect gross defects but still does not have the capability of reliably detecting and locating smaller defects, such as corrosion pits.

"If the largest threat is internal and the system can be removed from service, I would tend to look at ILI technology. The ability for the equipment to locate smaller anomalies with very accurate X-Y coordinate data is good. ILI also has the ability to discriminate between internal and external anomalies. It is able to detect actual wall loss."

However, there are some concerns with ILI, Edgar noted: "Some ILI tools are unable to see or resolve information inside of cased pipe. Anomaly orientation is still a problem. A decision must be made to look for anomalies oriented in the longitudinal direction or in the circumferential direction.

"Finally, the data need to be read and interpreted by a seasoned ILI technician. There are not enough highly skilled technicians to go around for the amount of work. The industry is going through a learning/growth mode at this time."

Continuous monitoring systems

Advances in SCADA systems and software are making the most vital contribution to pipeline integrity assurance, contends Allen Leatt, chief technology office for Acergy SA (formerly Stolt Offshore), Sunbury-on-Thames, England.

"The ability to monitor, manage, and record real-time information offers enhanced pipeline integrity for pipeline owners," he said. "Such systems enable integrity management decisions to be made on the understanding of the actual condition of the pipeline."

He noted that several companies have recognized the benefit of real-time simulation for various uses, such as operator training and process controls (e.g., the expectation of slugs in a first-stage separator).

"Acergy has a team of flow assurance specialists that are fully capable of providing models as input of the integrated SCADA/real-time simulation system."

While SCADA systems and flow modeling software help make the pipeline operations safer and help operators determine where problems might occur over a vast pipeline network, they're not measuring the actual changes in the pipe, Zaghloul pointed out.

"New materials that greatly increase the corrosion resistance or the strength of the pipelines are necessary to

New technology solutions will be needed to help the pipeline industry cope with the challenge of transporting the growing volumes of unconventional oil resources, such as kerogen from oil shale and bitumen from oil sands. Shown is the pipeline field infrastructure at the MacKay River oil sands project in Canada, operated by Petro-Canada. *Photo courtesy of Petro-Canada.*

ensure the integrity of planned pipelines, but the millions of miles of existing pipes are still at risk," he said. "New technologies, such as FOX-TEK's FT Sensor System, that can be installed on known problem areas on existing pipelines to continuously monitor changes in wall thickness, strain, or any deformation, promise to significantly increase the reliability of pipelines by allowing operators to know the state of the pipe at any time without having to re-excavate, visit the site, or suffer a loss of throughput."

Today, most technologies react to problems by providing a snapshot of the condition of a pipeline. Continuous monitoring systems for corrosion, pitting, and SCC would allow operators to gather and correlate pipeline condition data with operational conditions and then develop strategies to stop the growth of the degradation and prevent it from occurring in other locations.

—Essam Zaghloul, FOX-TEK Inc.

However, Leatt noted that while "the integration of fiber optic instrumentation along the pipeline will enable the real-time monitoring of the strain and temperature profile of a pipeline…only a limited number of pipelines can be cost-effectively equipped with such devices."

Game-changers

New technologies that allow operators to determine ways to mitigate problems such as corrosion, SCC, and leaks will be groundbreaking, Zaghloul reckons.

"Today, most technologies react to problems by providing a snapshot of the condition of a pipeline. Continuous monitoring systems for corrosion [e.g., non-intrusive methods such as FOX-TEK's FT Sensor System], pitting [e.g., field signature methods], and SCC [e.g., acoustic emission] would allow operators to gather and correlate pipeline condition data with operational conditions [pressure, temperature, product, inhibitor] and then develop strategies to stop the growth of the degradation and prevent it from occurring in other locations."

In the onshore pipeline construction business, new strain-based pipeline designs are having an impact in the onshore pipelaying world, said Zaghloul.

"Pipeline design/construction companies now include some form of monitoring in the new pipeline specification; however, the future in this area will be dominated by systems that allow continuous, distributed detection of leaks or deformation," he said.

"In new pipelines, corrosion and leaks from corrosion are almost a non-issue, but deformations from ground movement [frost heave, seismic] can put pipelines at risk," Zaghloul added. "Being able to detect the precise location and severity of the deformation over distances of tens to hundreds of miles is the goal of these new technologies—many of them based on fiber optics.

Edgar expects to see more emphasis on improvements in detection devices utilizing magnetic fields, electrical current flow, or induced harmonics.

"However, the most significant advancements will more likely occur in improved efficiencies and effectiveness within respective pipeline integrity programs, resulting in model programs emerging and being adopted," he said.

There is no single tool or technology that will ensure pipeline integrity, Edgar contends. "The area that we are currently concerned with is cased pipelines," he said. "There is currently only one approved or acceptable tool to test or look at buried, cased crossings, and it is more of a screening tool. We are currently looking at the possibility of other complimentary tools or technologies to help review cased crossings."

Another game-changing technology of tomorrow for Edgar is a system to identify the presence of excavators on a pipeline right-of-way in time to contact them before they start excavating.

"Such technology could include monitoring the right-of-way with satellites, the installation of sensing devices along the right-of-way, remote-controlled unmanned planes, or installing GPS locating devices in excavation and agriculture equipment.

Sub-One Technology, a small company based in Pleasanton, CA, thinks its new product represents just the kind of out-of-the-box thinking the industry needs—what it describes as a "revolutionary" means to coat the inside surfaces of pipes and parts used in oil production and transmission.

"The process lays down a thin, hard, anticorrosive coating that improves flow dynamics and reduces fouling," explained Sub-One Pres. and CEO Andrew Tudhope. "The film bonds with the pipe at a molecular level, making it unlikely to detach, like some existing epoxy or plastic coatings. In the unlikely event of a failure, the film returns to a near microscopic size of harmless carbon particles that flow out with the oil.

"Sub-One's technology still requires some development in order to coat the size parts required for oil transmission, but it should only be a matter of months."]