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International Petroleum News and Technology / www.ogjonline.com

Oil Sands Update

Fusion of climate models and geology adds insight
Oil discovery revives China foreland basin after long lull
European gas-supply security hinges on solving LNG issues


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OIL&GAS JOURNAL®

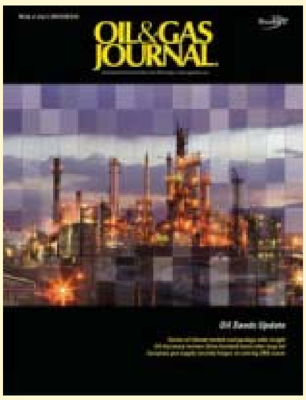
July 9, 2007
Volume 105.26

Oil Sands Update

Regular Features

Cover

Suncor Energy Inc.'s 90,000b/d refinery in Commerce City, Colo., processes Canadian crude from the company's oil sands operations. More upgrading and refining capacity will be needed in North America due to increased crude production from Canadian oil sands. The first article in this week's special report on oil sands, starting on p. 43, discusses the rapid increase in Alberta bitumen production. The second article, p. 54, covers capacity expansions in refining and upgrading to handle the additional crude supplies. Photo from Suncor.



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General Interest

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Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Europe opens gas, electricity markets July 1

Household customers across Europe became free to choose their gas and electricity suppliers on July 1, indicating the beginnings of a single, open energy market. The question, however, is whether customers will switch, as many utility firms on continental Europe continue to enjoy monopolies.

Legal unbundling of local electricity and gas distribution companies also was compulsory on July 1 to ensure independence from their parent companies and provide fair access to all suppliers in the distribution network. At transmission level legal unbundling was enforced in 2003.

Member states with open gas and electricity markets on July 1 were France, Bulgaria, Hungary, Poland, Romania, Slovakia, Slovenia, Lithuania, Luxembourg, Northern Ireland, Austria, Belgium, Czech Republic, Denmark, Germany, Spain, Netherlands, Italy, Ireland, Sweden, and the UK.

However, some member states have succeeded in obtaining derogations on introducing competition in their electricity markets; including Cyprus, Malta, and Estonia. Cyprus and Estonia have until 2013 to ensure there is a competitive electricity market.

Countries that have extensions to open their gas markets are Finland, Latvia, Greece, and Portugal, the last three of which have until 2010 to do so. "Cyprus and Malta do not have gas markets," a spokeswoman from the European Commission told OGJ.

The European Commission has championed an internal market, arguing it would provide competitive prices for consumers, energy efficiency, and investment in infrastructure. Developing a liberalized market has been difficult, with the latest report in January from the European Competition Commissioner, Neelie Kroes, showing that tougher rules to prevent discrimination are needed. Several legislative measures for greater unbundling are expected to be published in September.

According to UK researcher Datamonitor PLC, a single liberalized market "remains a distant possibility rather than an imminent reality" because of differing attitudes at a political level, market conditions, and varying degrees of competition.

On July 5 the European Commission will launch a charter of rights for energy consumers. The Commission hopes to have a fully functioning gas and electricity market with open competition and effective regulation in January 2009.

Denbury to buy more manufactured CO_2 for EOR

Denbury Resources Inc. agreed to buy carbon dioxide for enhanced oil recovery from Rentech Inc.'s proposed synthetic fuels plant to be built in Natchez, Miss.

Gareth Roberts, Denbury chief executive, said the Rentech agreement could supply additional CO_2 supplies as Denbury expands its tertiary operations in the Gulf of Mexico coastal area.

Initially, Denbury will use the CO_2 for EOR in Cranfield and Lake St. Johns fields near the Mississippi-Louisiana border, a company spokesman said, adding that there will be more CO_2 than will be needed by those fields.

The company holds operating acreage onshore in Louisiana, Alabama, in the Barnett Shale play near Fort Worth, Tex., and in Southeast Texas. Denbury plans to build a CO_2 pipeline from the Natchez plant. Details were not yet available.

The Natchez plant will be designed to use petroleum coke, coal, and biomass as feedstock and will use a patented Rentech derivative of the Fischer-Tropsch process, The particular feedstock to be used remains undetermined, a Rentech spokesman said.

Rentech's final investment decision on whether to build the plant will be made by Dec. 31, he said. Initial plans call for the plant to produce 25,000 b/d of synthetic fuels and specialty chemicals. It is to be completed in 2012 and would be expandable to 50,000 b/d.

Denbury said it expects to purchase 350-400 MMcfd of CO_2 from Rentech's Natchez proposed plant. Terms were not disclosed.

Previously, Denbury signed CO_2 purchase contracts for two other planned gasification plants proposed by Faustina Hydrogen Products LLC, one expected to be built near Donaldsonville, La., and another planned for construction near Beaumont, Tex.

If all three plants are built, total manufactured sources will provide Denbury with 750-850 MMcfd of CO_2 by 2012. Denbury already owns substantial CO_2 reserves on the Jackson Dome in south-central Mississippi. It operates and is expanding a network of CO_2 pipelines in the region.

Denbury said it plans to connect the manufactured sources of CO_2 to its natural source of CO_2, allowing the company to allocate production as required between the two sources. ✦

Exploration & Development — Quick Takes

Nigeria deal may be marginal field template

The Nigerian government has approved a marginal oil field farmout that a Houston firm believes could serve as a template for commercialization of several hundred undeveloped oil discoveries in the Niger Delta.

The government approved the farmout by ExxonMobil Corp.'s Mobil Producing Nigeria Unlimited unit and Nigerian National Petroleum Corp. of Ebok oil field on OML 67 to Oriental Energy Resources Ltd., Abuja.

Ebok, discovered in 1968, is in 150 ft of water 30 miles

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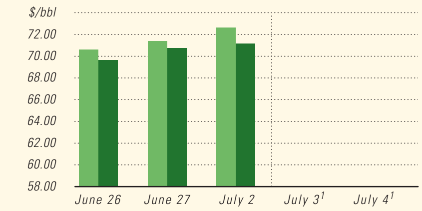
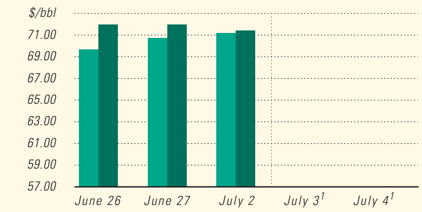
Industry Scoreboard

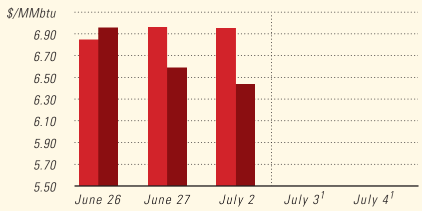
IPE BRENT / NYMEX LIGHT SWEET CRUDE



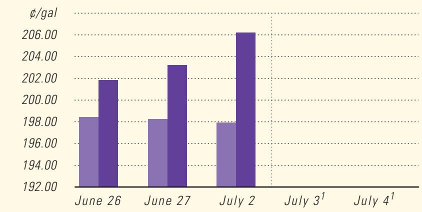
WTI CUSHING / BRENT SPOT



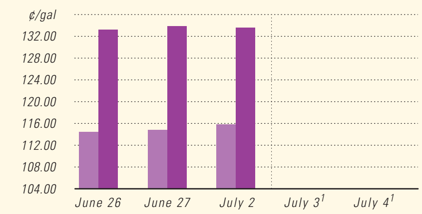
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



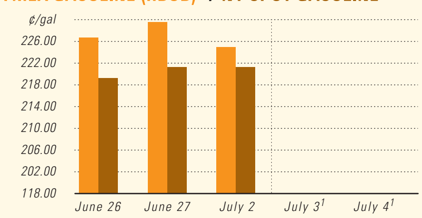
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available, [2]Reformulated gasoline blendstock for oxygen blending, [3]Nonoxygenated regular unleaded.

Scoreboard

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

off Nigeria near borders with Equatorial Guinea and Cameroon. Production of the field's 37° gravity oil could start as early as 2009.

Sovereign Oil & Gas Co. II LLC, Houston, conceived and negotiated the Ebok farmout on Oriental's behalf to compensate Oriental for partial loss of OML 115 that resulted from the 2000 maritime boundary treaty between Nigeria and Equatorial Guinea. That treaty facilitated ExxonMobil's development of giant Zafiro oil and gas field on Block B off Equatorial Guinea.

Sovereign has established a data room in Houston for Oriental's farmout to a qualified technical advisor of a 40% participation interest in Ebok, which has three untested wells as deep as 5,298 ft, one of which cut 271 ft of net oil pay in four sands at 2,600-3,600 ft.

Sovereign previously handled the farmout of nearby Okwok oil field to Oriental (OGJ Online, July 3, 2006). Oriental drilled four wells in Okwok in 2006 and plans to drill two more in 2007 with partner Addax Petroleum Corp., Calgary, which acquired 40% participating interest in Okwok in June 2006.

Mobil contributed Ebok field to Nigeria's marginal field program, and Nigeria in 2001 granted Oriental exclusive negotiating rights to take the Okwok and Ebok farmouts from Mobil as compensation for its loss to ExxonMobil in Equatorial Guinea waters.

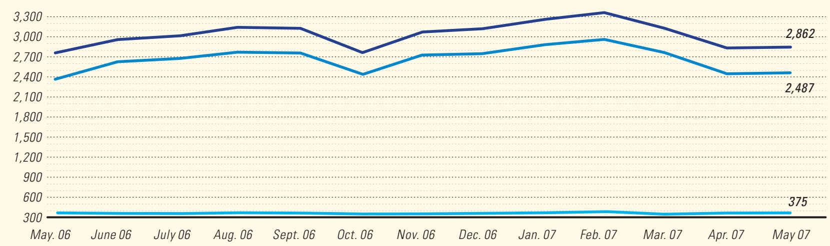
Petrovietnam, Petronas sign joint exploration deal

Petrovietnam has signed a contract with Malaysia's Petronas Carigali Overseas to drill for oil and gas in fields in the Gulf of Tonkin.

The fields lay 100 km offshore and cover nearly 12,000 sq km. They hold collective reserves of 50 billion cu m of gas and 45 million bbl of condensate, Petrovietnam said.

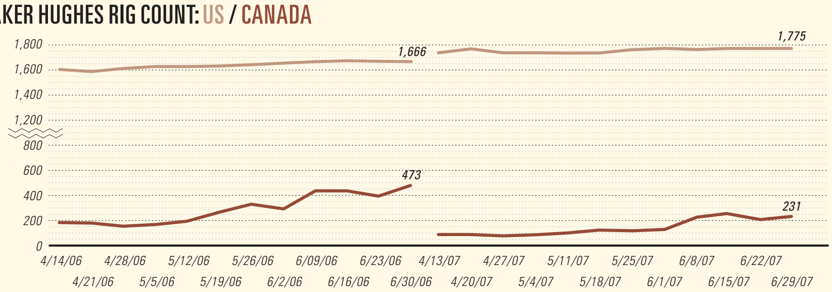
Under terms of the contract, the two companies will invest $57.7 million in exploration during the first 4 years, with Petrovietnam subsidiary Petrovietnam Exploration Group contributing 55%, and Petronas 45%.

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

Syria begins licensing round for offshore blocks

Syria's Oil Minister Sufian Al Alao and Syria Petroleum Co. General Manager Omar Al Hamad were in London in late June to promote Syria's first offshore licensing round, where four blocks covering 50, 000 sq km are available for lease. The deadline for applications is Sept. 27.

The selected blocks are in different petroleum basins where the expected potential for petroleum resources is "very high," said the Syrian petroleum ministry (OGJ Online, May 31, 2007).

The basins off Syria are the Levantine basin to the south, the Levantine basin to the north, the Iskenderun basin to the north and entering into Turkey territory, and the Cyprus basin, mostly off Cyprus.

Asked the status of talks between Syria and Turkey regarding maritime boundaries and how such discussions might affect licensing rounds, Al Alao said the two countries are friends. "We have selected acreage within Syria's territorial waters," adding that the foreign minister is having discussions with Turkey about border issues.

Most of the recent exploration in Syria has resulted in natural gas discoveries. Major gas projects under development in central Syria are Petro-Canada's Ash Shaer and Cherrife fields, which will produce an estimated 80 MMcfd of gas in 2010.

Life-of-field production from Ash Shaer and Cherrife is estimated at 500 bcf of gas equivalent over the 25-year contract.

Development is under way, and Petro-Canada has begun drilling another area, Al Hamad said.

Petro-Canada hopes that its appraisal wells will identify upside gas, which could double the initial life-of-field estimate and expand production capacity after initial start-up. Capital investment for the project is expected to be $460-660 million.

Syria also is looking at developing 2,000 Mw of wind power and has received bids for that work. The use of biofuels is being discussed, but Syria would have difficulty sourcing food crops, Al Alao added. ✦

Drilling & Production — *Quick Takes*

Rosa field off Angola starts oil production

Total SA reported the startup of oil production from deepwater Rosa field on Block 17 off Angola.

The field, discovered in January 1998, lies 135 km off the coast in 1,350 m of water. It is tied back 15 km from the Girassol floating production, storage, and offloading vessel, making it the first deepwater field of its size to be tied back to such a remote installation and in such water depths, Total said.

Rosa field, which is estimated to hold 370 million bbl of proved and probable oil reserves, will maintain the FPSO's production plateau at 250,000 b/d until early in the next decade, Total said.

Rosa field will comprise 25 wells, including 11 for water injection and 14 producers, which will be tied into four manifolds. The subsea installation consists of 64 km of insulated, pipe-in-pipe production flow lines and 40 km of water-injection lines linking Rosa to the FPSO vessel.

Block 17 is composed of four major zones: Girassol and Dalia, both on production; Pazflor, which is in the bidding process before sanction; and CLOV, a fourth production area based on the Cravo, Lirio, Violeta, and Orquidea discoveries, development of which is now being studied.

Future production from these fields will come in addition to the 500,000 b/d of oil currently pumped from the Girassol and Dalia structures on the block.

Total E&P Angola is operator of Block 17 and has a 40% interest. Partners are Esso Exploration Angola (Block 17) Ltd. 20%, BP Exploration (Angola) Ltd. 16.67%, Statoil Angola Block 17 AS 13.33%, and Norsk Hydro Dezassete AS 10%.

Rancher plans CO_2 EOR in Wyoming fields

Rancher Energy Corp. has selected two contractors to implement the front-end engineering and design of an enhanced oil recovery project using carbon dioxide injection in Powder River basin fields in Wyoming.

Rancher expects to recover at least 115 million bbl of oil by injecting CO_2 into the reservoirs of three fields in the southwest corner of the basin—South Glenrock B, Cole Creek South, and Big Muddy—all in Wyoming's Converse County.

Pipeline engineering consultant Trigon EPC LLC and surface facilities contractor Nicholas Consulting Group Inc. will conduct the FEED studies for construction of CO_2 infrastructure and a pipeline connecting Rancher's fields with a CO_2 pipeline operated by Anadarko Petroleum Corp.

Anadarko, under a long-term supply agreement, will deliver 25-40 MMcfd of CO_2 to Rancher for its EOR project.

Rancher Energy Pres. and Chief Executive John Works said the project is in the planning phase and the company does not have details on routing, timetable, and financial arrangements for the pipeline and surface facilities. The company also has not yet obtained financing for development of the fields and related infrastructure.

Rancher acquired the three fields earlier this year. The company has a 93.73% interest in South Glenrock B field and a 100% interest in the other two.

The 7,070-acre South Glenrock field, discovered in 1950 by Conoco Inc., is organized into three units: A, B, and C. It has estimated remaining recoverable reserves of 40 million bbl. Field production from the Dakota and Muddy sandstones have been maintained by secondary recovery initiated in 1961. Current gross production from Unit B is 210 b/d, primarily 35° oil.

Cole Creek South field, covering 2,080 acres, was discovered in 1948 by Phillips Petroleum Co. It has remaining oil reserves of 10.8 million bbl. The field has been water-flooded since the 1960s and currently produces 80 b/d of 35° oil.

Covering 8,500 acres, Big Muddy field is producing about 60 b/d. Since its discovery in 1916 by Conoco, it has produced about 52 million bbl of oil from several producing zones, of which the Wall Creek formation has been the most prolific, producing 32 million bbl at a depth of 3,500 ft. Geologically, the field is analogous to nearby Salt Creek field, in which Anadarko is conducting a successful CO_2 injection program.

Soco plans for 2008 Ca Ngu Vang oil deliveries

Soco International plans initial oil deliveries from its Ca Ngu Vang field in Vietnam in the first half of 2008. It is moving ahead with exploration and appraisal and will build infrastructure on Block 9-2, which contains the field.

The appraisal well tested at a maximum combined rate of 7,050 boe/d, with 5,333 b/d of oil and 10.3 MMcfd of gas in 2006.

Soco said Vietnam is a core area and that the Te Giac Den-1X well on Block 16-1 in Vietnam indicated oil and gas shows and an overpressured environment in the Oligocene interval. No testing has been carried out on that well.

In Yemen, Soco plans to delineate the western and southern parameters of Kharir field. Production facilities are being expanded "in anticipation of reaching 70,000 b/d of export capacity," the company added. Soco has acquired three rigs to drill on the block throughout the year, and will focus on development and injector wells to increase basement productivity and production capability.

The company hopes in early 2008 to drill its first exploratory well on the Marine XI block, off Congo (Brazzaville). It expects to select drilling targets for its West African portfolio in the third quarter.

Later this year Soco also will shoot a 2D seismic survey on the Nganzi and Cabinda North blocks in Congo (former Zaire).

BP terminal work to lift gas recovery off UK

BP PLC expects to increase gas recovery by 30% from West Sole and Amethyst fields in the southern UK North Sea by boosting compression in a reconfiguration of onshore terminals.

The company plans to invest $250 million to add compression at its Dimlington terminal and close its adjacent, unmanned Easington terminal by early 2008.

Dimlington now receives gas directly from fields in BP's Cleeton area and Ravenspurn fields along with gas from southern UK North Sea fields operated by other companies.

Easington receives gas from West Sole, Hyde, Newsham, and Hoton fields and passes it to Dimlington.

Amethyst gas flows to Centrica Storage Ltd.'s gas processing terminal at Easington. ✦

Processing — *Quick Takes*

EPA responds to Coffeyville refinery spill

Major flooding caused an oil spill from Coffeyville Resources LLC's refinery and fertilizer plant at Coffeyville, Kan. The oil spilled into the Verdigris River, flooded from several days of heavy rainfall. The 100,000 b/cd Coffeyville refinery was under 4-6 ft of water on July 3, emergency officials said.

Workers were able to return to some administrative offices and warehouses on July 4. But the extent of damages remained unknown until floodwaters recede more. It was unclear when the refinery might resume operations.

The US Environmental Protection Agency sent coordinators to Coffeyville for pollution assessments, the EPA Region 7 office in Kansas City, Kan., reported.

The refinery was shut on June 30, and flood waters breached a Coffeyville levee on July 1. The flooding caused an oil spill from storage tanks. The spill was isolated and stopped, a refinery spokesman said.

No estimate is currently available on cost of the damages. Coffeyville Resources management said.

"A tank system containing crude oil overflowed during the early hours of the flood, and subsequent record levels of flood waters have swept the oil from containment areas within the refinery," a refinery news release said. "No estimate was immediately available as to the amount of crude oil lost as access to tank gauges has been restricted by high water."

The company also reported a "small ammonia release" but said there was no threat to the immediate community. The nitrogen fertilizer plant is at higher elevation than the refinery, but it also remained closed.

The Verdigris River flows into Oologah Lake, a water source for Tulsa. Officials believe the oil will dissipate before it ever reaches the lake, said a spokesman for the Tulsa District of the US Army Corps of Engineers. Tulsa water plant operators along the Verdigris and the Oologah Lake reported no sign of the oil spill on July 2.

Exxsol Jurong Island fluids plant to be expanded

ExxonMobil Chemical said it will add 130,000 tonnes/year of capacity to its Exxsol hydrocarbon fluids plant in Jurong Island, Singapore, raising commercial production to more than 500,000 tonnes by yearend 2008.

ExxonMobil said the increased capacity is designed to meet the demand for differentiated hydrocarbon fluid products, which is growing annually at an average rate of 5-6% in Asia Pacific.

The hydrocarbon fluids are used for such uses as drilling mud oil used in oil exploration, metal working, polymer and pharmaceuticals processing, industrial cleaning, adhesives, and coatings.

Asia's increasing demand for the fluids comes from strong industrial growth, accompanied by heightened health, safety, and environmental requirements.

The more-stringent requirements include specifications of the Globally Harmonized System, the international agreement to classify products uniformly, and European legislation known as REACH (Registration, Evaluation, and Authorization of Chemicals).

The firm's fluids portfolio is positioned to meet or exceed such increasingly stringent regulatory and environmental requirements, according to Kittiphong Limsuwannarot, ExxonMobil Chemical's hydrocarbon fluids global marketing manager.

Siemens to supply equipment for propylene plants

Datang International Power Generation Co. Ltd. has let a €20 million contract to Siemens Power Generation to supply core equipment for the world's first methanol-to-propylene (MTP) plant to be built in China.

In the MTP process, natural gas or coal is used as feedstock to produce methanol, which is then converted to propylene.

China's MTP project comprises two propylene plants that will use Lurgi AG's plastics-from-coal technology. The plants, due on stream in late 2008 and early 2009, will each produce about 500,000 tonnes/year of polypropylene from coal (OGJ Online, Dec. 4, 2006, Newsletter).

The Siemens contract includes the supply of a synthesis gas compressor, which will compress the synthesis gas to 86 bar from 31.7 bar, and a propylene compressor that will compress the propylene to 17.6 bar from 1.05 bar.

Both compressors are single-shaft horizontally split compressors, driven by a SST-600 condensing steam turbine with an output of over 40 Mw. They are scheduled for delivery in the spring of 2008. ✦

Transportation — *Quick Takes*

BG to sell Karachaganak gas to KazRosGaz

KazRosGaz, a joint venture of OAO Gazprom and KazMunaiGaz, will buy 16 billion cu m/year of gas from BG Group PLC and its partners in the third phase of the Karachaganak project in northwest Kazakhstan. KazRosGaz also will purchase increased volumes of condensate, but figures for this were not available.

The contract lasts for 15 years. Gas is expected to come on stream in 2012 following completion of the $8 billion expansion at Karachaganak.

Production is expected to double at Karachaganak once the third phase is sanctioned in 2008 to 16 billion cu m/year of gas and 16.5 million tonnes/year of condensate. The Orenburg processing plant in Russia currently handles 8 billion cu m/year of untreated Karachaganak gas.

Mark Carne, BG executive vice-president, Europe and Central Asia, said the gas sales agreement covers more than 7 tcf of gas. "Additional gas sales resulting from the expansion will also enable the venture to increase liquids production for export to high-value western markets," he added.

BG is the joint operator of Karachaganak gas and condensate field with a 32.5% interest. Karachaganak holds estimated gross reserves of more than 2.4 billion bbl of condensate and 48 tcf of gas. Partners are Eni SPA (joint operator) with a 32.5% stake, Chevron Corp. with 20% interest, and OAO Lukoil with 15%.

Thailand's new gas pipeline starts deliveries

Thailand has completed the first phase of its $1 billion, third gas transmission line, and the pipeline has begun commercial operations.

The pipeline—424 km of 42-in. line offshore and 5km of 42-in. and 110-km of 36-in. line onshore—is delivering 250 MMcfd of gas from Chevron Exploration & Production's Erawan gas field in the Gulf of Thailand to Bang Pakong, east of Bangkok.

The deliveries augment gas transmitted from the gulf fields through PTT PLC's two 20-year-old transmission lines that are operating at their capacity limits of 1,800 MMcfd, officials of the state-controlled PTT said.

Construction of the second section of the new transmission line—334.5 km of 42-in. pipeline—is 6-9 months behind schedule and will be completed in first-quarter 2008.

It will connect Erawan field with Arthit gas field and extend into Block A-18 of the Malaysia-Thailand Joint Development Area in the southern part of the gulf.

Completion of the second stage will raise gas throughput volume in the third pipeline by 500 MMcfd to its maximum capacity of 750 MMcfd. PTT also plans to install a gas compression facility at Erawan field to raise the third gas line's total throughput capacity to 1,900 MMcfd in 2010, when additional supplies from fields in the southern gulf become available.

Chevron to increase Keystone storage capacity

Chevron Pipe Line Co. plans to expand the working gas capacity of its Keystone Gas Storage facility to 7 bcf from 5 bcf. Keystone is a high-deliverability natural gas storage salt cavern in the Permian basin production region of West Texas.

The company will hold an open season in third quarter to gauge interest in firm gas storage services for the additional 2 bcf of capacity, expected to be realized from two additional caverns scheduled to be completed in early 2010.

The project has received Texas Railroad Commission approvals and permits to develop these caverns—the facility's sixth and seventh. The fifth cavern was placed in service during fourth-quarter 2006.

The planned expansion is expected to increase the facility's injection capability by 40 MMcfd to 200 MMcfd. The facility's withdrawal capability currently is 400 MMcfd.

Keystone, which has been in service since September 2002, connects to the pipelines of El Paso Natural Gas, Transwestern Gas Co., and Northern Natural Gas Co. These connections allow Keystone to serve customers in Texas as well as the Midwestern and Western interstate regions.

Quebec approves Cacouna Energy LNG project

The Quebec government approved a proposal to construct the Cacouna Energy LNG project, a joint project of Petro-Canada and TransCanada Corp.

An LNG receiving, storing, and regasifying terminal is to be built at the existing harbor at Gros Cacouna, Quebec—about 15 km northeast of Rivière-du-Loup (OGJ, Sept. 13, 2004, Newsletter). Terminal plans call for an average send-out capacity of 500 MMcfd/year of natural gas. Canada's Environmental Assessment Joint Review Panel also approved the proposed project.

The partners will share the $660 million construction costs equally. TransCanada will operate the facility, and Petro-Canada will supply the LNG. The terminal could be in service by yearend 2010, the partners said. ✦

Calendar

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

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

2007

JULY

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

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

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

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

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

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

AUGUST

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

Diesel Engine-Efficiency and Emissions Research (DEER) Conference, Detroit, (540) 937-1739, e-mail: kim@cemamerica.com, website: www1.eere.energy.gov/vehiclesandfuels/resources/conferences/deer/index.html. 12-16.

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

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

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

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

SEPTEMBER

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

SPE/EAGE Reservoir Characterization and

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

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

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

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

Iraq Petroleum Conference, Dubai, +44 (0)20 7978 0075, +44 (0)20 7978 0099 (fax) website: www.thecwcgroup.com. 8-10.

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

Global Refining Strategies Summit, Houston, (416) 214-3400, x3046, (416) 214-3403 (fax), website: www.globalrefiningsummit.com. 10-11.

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

Annual LNG Tech Global Summit, Rotterdam, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.lngsummit.com. 10-12.

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

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

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

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

United States Association for Energy Economics/IAEE North American Conference, Houston, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 16-19.

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

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

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

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

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

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

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 337-1644 (fax), e-mail: Twilson@EventsiaGroup.com, website: www.ecc-association.org. 26-29.

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

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

OCTOBER

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

✦Well Control Gulf of Mexico Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: Jamie@pe.tamu.edu. 2-3.

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

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

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

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

Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 3-6.

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

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

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

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

NPRA Q&A and Technology Forum, Austin, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 9-12.

Deep Offshore Technology (DOT) International Conference & Exhibition, Stavanger, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 10-12.

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UK decommissioning issues

Uchenna Izundu
International Editor

Tidying and simplifying the rules on decommissioning oil and gas facilities in the UK North Sea is one of the pressing issues facing John Hutton, the new minister to lead the Department for Business, Enterprise, and Regulatory Reform (DBERR), formerly known as the Department for Trade & Industry.

Oil companies have complained that in its present state the Petroleum Act 1998 is unfair and complex because it requires every company that has had an interest in an offshore installation to draw up a decommissioning plan, even if it sells the interest or the entire asset. Although some companies have received exemptions from decommissioning liabilities because of special circumstances, Section 34 of the act allows the government to reinstate the requirements.

Companies served with a notice become jointly and severally liable to submit a decommissioning program for ministerial approval and to ensure that the program is implemented. This, of course, raises additional financial obligations as well as health, safety, and environmental responsibilities. As the UK tax regime has changed several times in the past 5 years, fiscal uncertainty has complicated decommissioning as companies are unsure about the level of tax relief available to offset decommissioning costs.

Decommissioning delayed

For now, decommissioning is being delayed by the strength of oil and gas prices, which has encouraged exploration and allowed the development of small fields tied back to existing production platforms. Ultimately, however, decommissioning liabilities undermine the government's objective of maximizing recovery from the UK continental shelf (UKCS).

According to the latest UKCS economic activity report by Oil & Gas UK, about 470 installations, 10,000 km of pipelines, 15 onshore terminals, and 5,000 wells await decommissioning. Costs estimates range from £15 billion to £20 billion.

The group estimates that elevated oil and gas prices over the past 4 years have delayed decommissioning by 2 years and suggests that decommissioning costs can be reduced "through greater coordination with the supply chain and a more systematic approach across the industry."

But questions about decommissioning are slowing asset deals as buyers and sellers are unsure about the limits of their responsibilities.

"Uncertainty over the future fiscal treatment of decommissioning costs is forcing companies to over-provide, making asset trading more costly," an Oil & Gas UK spokeswoman told OGJ. "The drop in the level of asset trading means potential investment by new owners who see value in extracting more costly oil and gas reserves is not being made and overall recovery will be lower."

The UK government has launched a consultation with industry on ways to improve the statutory decommissioning regime and to minimize the risk of liabilities falling on the public purse. The consultation closes on Sept. 13, 2007.

Discussions of regulatory and fiscal change are under way in PILOT (the government-industry forum chaired by the secretary of state) and between the industry and several government agencies. Talks on the fiscal element are expected to conclude in the autumn.

What are the possible solutions?

Oil companies want regulatory reform so they can drop any decommissioning liabilities once they leave a license under a DBERR-approved decommissioning cost-provision deed affording robust financial security for all parties. After 2 years of intense discussions within PILOT, Oil & Gas UK plans to launch a deed in August illustrating how financial security must be provided for all parties involved in a transaction.

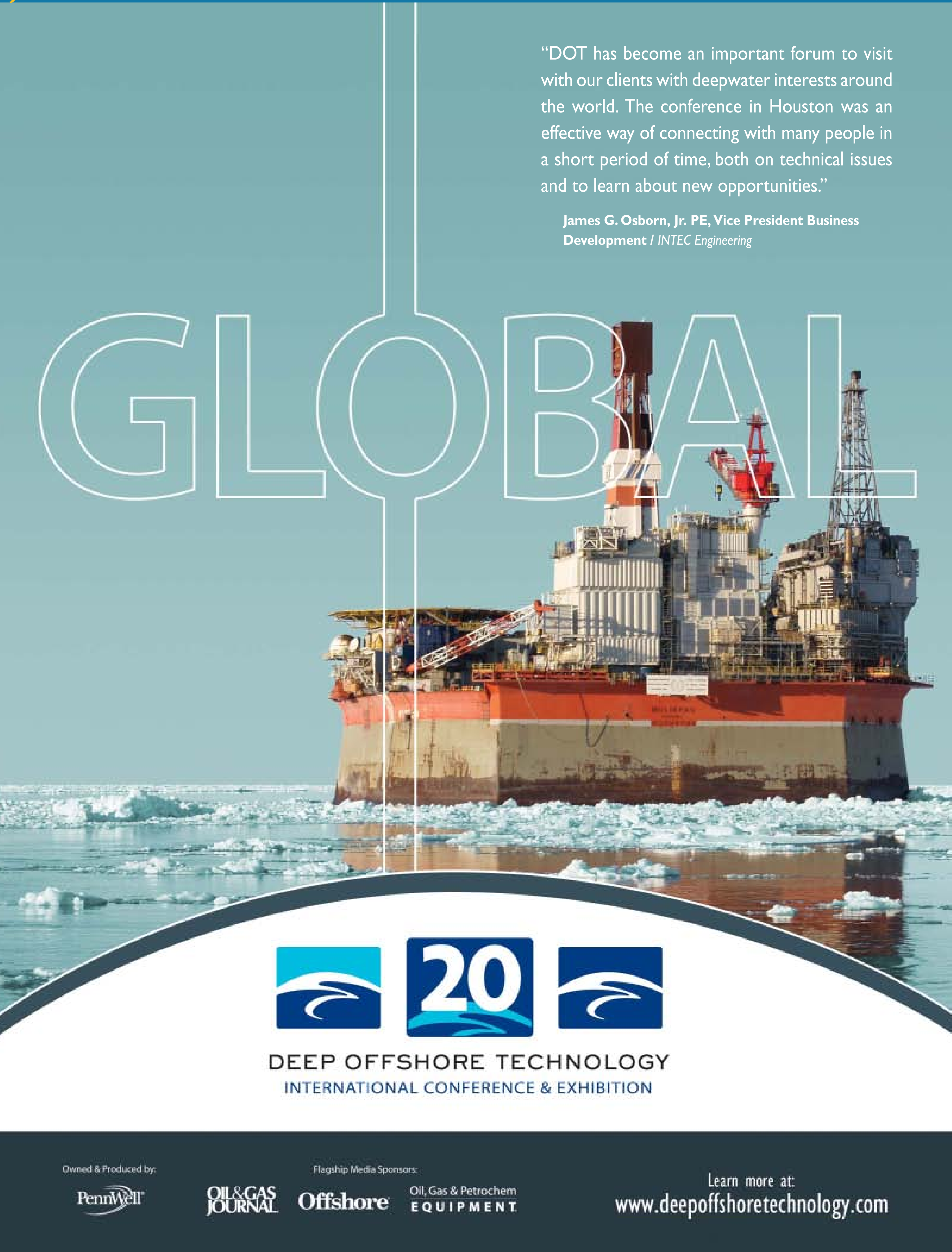
The industry also needs assurance about the availability of decommissioning tax relief and after-tax treatment of permit securitization. According to Oil & Gas UK, this will increase the funds available for asset trading.

Consultation responses

It will be interesting to hear the responses of the industry to the decommissioning challenge that Hutton must steer through its next phase. As a mature province, the UKCS is facing major international competition from other places for investment, innovation, and development.

Whatever emerges from the consultation, it is imperative that public education is at the forefront to ensure thorough understanding of the issues at hand. The oil and gas industry has often been misunderstood and perceived as selfish, greedy, and careless about the environment.

No company wants to repeat the controversy Royal Dutch Shell PLC endured in 1995-98 over the Brent spar loading buoy. The company initially planned to clean and scuttle the unit in the deep Atlantic but under heavy protest eventually dismantled it and used the metal for quay construction (OGJ, Jan. 15, 2001, p. 15). ✦


"DOT has become an important forum to visit with our clients with deepwater interests around the world. The conference in Houston was an effective way of connecting with many people in a short period of time, both on technical issues and to learn about new opportunities."
James G. Osborn, Jr. PE, Vice President Business Development / INTEC Engineering
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Iran's gasoline fracture

From the perspective of the US and other nations hoping for stability in the Middle East, regime change would be more than welcome in Iran. Any of a number of countries probably would act to bring change about if it could devise some promising and acceptable strategy for getting the job done. So far, no such strategy has emerged. Maybe it won't be necessary.

Evidence mounts that in Iraq and Afghanistan the US and its allies are fighting a proxy war with the Islamic Republic. Iranian weapons and agents are turning up in both places. The conflict broadens to the extent US entanglement in Iraq constitutes war against terrorism, Iranian links to which are well known. Beyond Iraq and Afghanistan, Iran is believed to support Hamas in Gaza, Hizbollah in Lebanon, and shady groups in Syria.

Deadly contest

In this deadly contest, events so far favor Iran. In Iraq, the US is expending lives and resources in a quagmire with no end in sight. It has lost stature abroad and political cohesion at home. Iranian President Mahmoud Ahmadinejad, meanwhile, courts other Persian Gulf leaders eager to hedge their bets against a US pull-out from Iraq and mocks the United Nations with nuclear work.

Iran has much to gain if the US flees Iraq and by all evidence is pursuing the goal with nasty enthusiasm. The Islamic Republic acts determined not only to fill whatever power vacuum might develop in Iraq but also to amplify its regional influence, denials notwithstanding, with nuclear weapons.

Iranian domination of the Persian Gulf would, among other things, overhaul the oil market. Since the late 1980s, the Islamic Republic's consistently expressed price aggression has been kept in check by more-sensible gulf producers led by Saudi Arabia. A nuclear Iran with 4 million b/d of crude production would tip that balance, especially if it were able to co-opt Iraqi output destined not to stay below 2 million b/d forever. And it could count on help from Venezuela, the maverick president of which, Hugo Chavez, met recently in Tehran with Ahmadinejad and Supreme Leader Ayatollah Ali Khamenei.

For the US and its allies in and out of the gulf, options are limited. Among the worst of them is an air raid on Iranian nuclear sites. While possession of nuclear weapons by Iran's ruling mullahs is no cheery prospect, preventive incursion would do more harm than good. Devastation would be impossible to confine to narrowly targeted air strikes. Tehran would retaliate with terrorist attacks, producing a body-count contest nobody wants. Oil prices would zoom.

What's more, military attacks would give Ahmadinejad political support he doesn't now enjoy. While his international truculence is said to be popular in Iran, his domestic policies are not. Indeed, Iran's large, young, and underemployed population generally loathes the oppressive clergy from which Ahmadinejad takes orders. Military attacks would congeal nationalistic support around a vile regime.

Better strategy

A better strategy is to let internal pressure widen Iran's political fractures. The oil-dependent Iranian economy is an ironic source of fundamental political weakness. Lavish subsidies of food and vehicle fuel, much of it imported, keep the government budget in deficit. Imposition of gasoline rationing late last month, following a 25% price hike in May, was a sure sign of strain. The move provoked riots and the torching of service stations in several cities. On July 3, during a news blackout, the Energy Committee of the Iranian parliament said the government would amend the rationing order to supply motorists "according to their real needs within the next 2 months" and called on the cabinet to supply the fuel.

The promise might relax immediate tensions. That it had to be made, however, signals the inevitably approaching end to Tehran's ability to buy political calm with cheap fuel. A large fracture then will grow. It will be a step of unpredictable importance toward regime change. For outsiders, it will be a time to keep warplanes in their hangars and to imagine a world in which Iran shuns the role of international menace. ✦

Fusion of climate models and geology adds insight

Paula Dittrick
Senior Staff Writer

Geologic knowledge can provide vital information for scientists modeling the climate, said Eric J. Barron, dean of the Jackson School of Geosciences at the University of Texas, Austin.

Climate models create mathematical representations of atmospheric patterns and ocean movements. The current focus is on models that relate temperature to concentrations of carbon dioxide in the atmosphere.

Scientists are developing increasingly sophisticated models that explain and project climate change.

For oil and gas exploration, climate modeling is a concept that has come and gone and now come again, Barron said. Scientists report great strides since 20-25 years ago in their ability to generate simulations that accurately examine specific time periods and basins.

"The geologic record is a window on how the earth can change," Barron said of the emerging climate-change science. "I like to say that climate modeling brings the discipline of forecasting to the geologic record."

He serves on an Association of American Petroleum Geologists special committee on climate changes. At the AAPG April convention in Long Beach, Calif., he presented a paper entitled "Is It Time for a Rebirth in the Geologic Applications of Climate Models?"

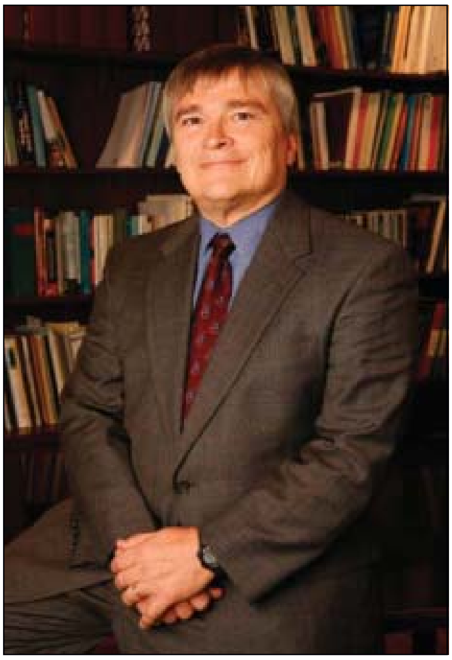
The committee is evaluating AAPG's policy statement on climate change, which Barron calls "a fast-moving field in some ways." The committee addresses whether AAPG should renew its statement to reflect growing public concern about climate change. "We're also looking for the opportunity to provide more education for AAPG members on climate change topics."

Climate projections have informed decision-makers worldwide about water resource management, ecosystems maintenance, and alternative energy development. Despite an inherent uncertainty in climate models, the science is gaining corporate attention as executives across all types of industries try to address global warming issues.

"It used to be that many of the automakers and oil and gas companies had mixed views about the issue of global warming," Barron said. "But I think the debate is being more broadly engaged than it ever has been. In my opinion, when this country starts talking about energy issues and global warming, it's almost as if you are for or against—you can do it this way but not that way. I hope we are coming to realize that there are all sorts of degrees, issues, and responses. We can actually address them quite intelligently if we set out to do so."

An advocate of integrating intelligent

"The geologic record is a window on how the earth can change. I like to say that climate modeling brings the discipline of forecasting to the geologic record." ***—University of Texas Jackson School of Geosciences Dean Eric J. Barron***



energy policy with climate policy, Barron notes that industrialized countries are better able to address environmental issues than many developing countries are. "It's very clear that the countries that have the most problems associated with any kind of environmental change are those countries that do not have economies that enable them to address issues. So I think robust economies are much more capable of addressing these issues. It's hard to separate energy from economic well-being."

Climate models

Climate modeling stems from science that started in the 1920s to predict weather. But climate modeling differs greatly from weather forecasting. Weather forecasters are concerned about near-term, localized phenomena while climate modelers are concerned with long-term, large-scale features and variables that respond to external pressures, called forcings. The models involve land, oceans, ice, interactive atmospheric aerosols, atmospheric chemistry, and the carbon cycle.

Climate models are very complex. Hundreds of independent teams having diverse expertise are comparing models primarily based on simulations performed in 2004-05 for the United Nations Intergovernmental Panel on Climate Change.

Barron said climate models can be applied to geological information in two ways. One involves improving knowledge of climate change so scientists can better project the future, and the other involves new ways of studying Earth's history.

In the typical model study of future climates, scientists study the period from 1895 to 2100. For the first 100 years, researchers have information to compare against their models, but they lack this information for the next century. Various models get very different results for the next century. The question confronting climate modelers is whether they can believe models based on simulating 100 years of history in which the changes were relatively modest.

"A great deal of change has a lot of significance for humans, while a little change has much less significance for humans," Barron said. "One application here is the geologic record is a wonderful way to explore the versatility and capability of climate models. How well can you predict the past? The one thing geology has is abundant examples of climate change. So can we replicate those changes? If we can then we certainly are adding insight."

The second application is exploration of past time periods. In the study of Earth's history, researchers start with a set of observations. These can be derived from cores or outcrops containing pollen or isotopes that document past conditions.

"You constantly try to build a bigger picture from a limited number of observations," Barron said. "You come up with this bigger picture, and you test it by trying to gather some more observations. A really good model gives you the potential to say, 'OK, I know what the physical geography of the continent was, and I know a lot of the conditions. What environment do I predict for a time period in the past?' Then all those observations become an opportunity to prove whether you did it right or wrong."

Climate modelers try to make world reconstruction projections that are independent of key observations, Barron said. If the observations fit the predictions, then scientists have more confidence when they look at geographic areas lacking many observations.

Barron said: "It's a way to fill in a lot of the holes if you can prove your predictions work well. If you attempt to reconstruct a past set of conditions, you tend to think rather simply about particular variables: Was it hot or cold? Was it dry or wet? Whereas what you are looking at could be one wet season and one dry season....

"The type of information that you derive could turn out to provide much more insight as well. Not only are you filling in the gaps but you are starting to tie what you see in the geologic record with a more defined set of physical variables. For instance, consider predicting severe weather in the past. Storms are capable of moving the sediments and altering the record."

Tsunamis and hurricanes inundate coastal regions, depositing sandy sediment across broad areas. Scientists believe identifying a sandy bed in the geologic record as a tsunami or hurricane deposit is crucial to accurately identifying a recurrent interval, which in turn could produce a statistical measurement regarding the probability of future tsunamis or hurricanes.

The variables in a climate model also are crucial to the model's accuracy. For instance, scientists are examining whether greenhouse gases (GHGs)

Career highlights

Eric J. Barron joined the University of Texas at Austin as dean of the Jackson School of Geosciences in 2006. He succeeded William L. Fisher. Barron's research interests are climatology, numerical modeling, and Earth history.

Previously, he was dean of the College of Earth and Mineral Sciences at Penn State. Before that he directed Pennsylvania State University's College of Earth and Mineral Sciences Earth System Science Center and was a geosciences professor.

Education

Barron has a BS degree in geology from Florida State University and a MS degree in oceanography and a Ph.D in oceanography from the University of Miami.

Organizations

Barron belongs to the American Geophysical Union and the American Association for the Advancement of Science. He has chaired several national research boards, including the Board on Atmospheric Sciences and Climate of the National Academies (1997-2003). He is chairman of the Consortium for Ocean Leadership, a combination of the former Consortium for Oceanographic Research and Education with the Joint Oceanographic Research Institutions.

influenced past climates. Ice cores document past GHG levels. When building climate models, scientists could not get the models to simulate past climate change unless they considered changes in CO_2 levels. Although scientists are not sure why the CO_2 levels changed, research indicates the changes contribute to observed warming. Climate scientists examine the cause-effect relationship between CO_2 levels and warming.

Climate models project additional warming on a global scale. About 30 major centers for atmospheric or ocean research develop climate models.

Universities involved in climate modeling in Earth history are the University of California, Santa Cruz; the University of New Mexico; the University of Michigan; Purdue University; and Penn State.

Barron said the list of universities involved is growing, and he believes climate models will continue to improve.

"If you have confidence that these models can predict the past, it starts to give you more confidence that they can predict the future. There are definite flaws. There are definitely things in Earth history that we are having trouble predicting," Barron said. "There are cases where you can safely say we don't understand this problem well enough. There are other cases fitting exactly as predicted, and that's where you start to believe you have something to say." ✦

Loss of three companies could hurt Venezuelan investment

Sam Fletcher
Senior Writer

The withdrawal of ExxonMobil Corp., ConocoPhilips, and Petro-Canada from Venezuela under government pressure to nationalize private industry in that country could potentially limit the development of four heavy-crude projects, that could produce 600,000 b/d from the Orinoco reserve, analysts say.

ExxonMobil and ConocoPhilips quit their Venezuelan operations when officers of the two companies refused to sign a memorandum of understanding that would make them minority partners in multibillion-dollar heavy-oil projects after surrendering controlling ownership to Petroleos de Venezuela SA (PDVSA), the national oil company.

Petro-Canada, Calgary, said it also is pulling out of Venezuela, having rejected new nationalistic terms for oil projects and passed its working interest in an oil discovery to the Venezuelan government. Through its predecessors, Petro-Canada has had assets in Venezuela since 1996.

In western Venezuela, Petro-Canada holds a 50% working interest in the ExxonMobil-operated La Ceiba Block on the eastern shores of Lake Maracaibo. The partners submitted a field development plan to PDVSA and the Venezuelan government in December 2005. In March 2006 PDVSA shut down ExxonMobil's 12,000 b/d production from La Ceiba oil field. Petro-Canada said at that time its production had already been shut in. PDVSA gave no reason for its decision to halt the loading of oil from La Ceiba (OGJ Online, Mar. 24, 2006).

Prior to the expropriation of its interests, ConocoPhillips held a 50.1% interest in Petrozuata, a 40% interest in Hamaca, and a 32.5% interest in Corocoro heavy oil projects in Venezuela (OGJ Online, June 27, 2007). The only operation ConocoPhillips retains in Venezuela is a minority interest in development of an offshore natural gas field.

The company said it expects to record a complete impairment of its entire interest in its oil projects in Venezuela of $4.5 billion, before and after tax, in its second-quarter financial results. Although hopeful that the negotiations will be successful, ConocoPhillips has "preserved all legal rights including international arbitration," it said.

Negotiations for compensation settlements for the international companies could last for up to 6 months and must go to international arbitration if no accord is reached. In the process, US companies may seek to attach PDVSA assets in the US, such as refineries of its subsidiary, Citgo Petroleum, pending a final agreement. Venezuela President Hugo Chavez has said he might sell Citgo or cut off oil sales to the US, which gets 14% of its oil imports from Venezuela.

A number of relief options may be available to the companies, said Neil Popovic, an attorney in the law offices of Heller Ehrman, and Alex Lathrop, a member of Heller Ehrman's Insurance Recovery Group. "Among these are political risk insurance (PRI), bilateral investment treaties (BITs) and other analogous bilateral and multilateral treaties, and any investment agreement between the company and the host government. For some companies, recovering under a PRI policy and assigning their direct claims against the host government to their insurer may be preferable to direct arbitration against the host government," they said (OGJ, June 25, 2007, p. 20).

ExxonMobil

In response to Venezuela's demand for a 60% or more stake in the Orinoco basin heavy oil projects by May 1, ExxonMobil announced Mar. 1 that it would hand over to PDVSA operations of Cerro Negro—one of the four Orinoco basin oil fields that it operates as part of a JV with BP. ExxonMobil has not yet indicated what other steps it might take. Attempts to reach company representatives at presstime last week in Houston and at its Irving, Tex., headquarters were unsuccessful.

ExxonMobil was the only major

international oil company to challenge Venezuela's 2004 royalty increase on heavy oil production and the only one to sell its interest in a field to avoid having to negotiate a new contract with PDVSA as the operator. In 2006, it ceased investments and postponed drilling in Venezuela.

ExxonMobil sold its 25% interest in Venezuela's Quiamare-La Ceiba field to Repsol YPF SA, which held the remaining 75% interest. The field, located in Anzoategui, produces 15,000 b/d of oil. Repsol YPF agreed to migrate the terms of the field's contract to a joint venture that PDVSA controlled under changes in the country's hydrocarbons law. PDVSA subsequently removed ExxonMobil from a multibillion-dollar petrochemical project, claiming the company was holding up the project launch.

ExxonMobil has no other operations in the country, having earlier sold its 49 branded gas stations in Venezuela.

Other companies' actions

Without investment capital to develop fully its extensive oil and gas reserves, Venezuela in the 1960s entered into service contracts with numerous foreign oil companies to invest in and operate Venezuela's oil fields. During that time, almost 60 foreign companies, many from the US, participated in the Venezuelan oil sector at the government's invitation.

In recent years as rising oil prices spurred the country's rapid economic growth, Venezuela's gross domestic product increased by 17.9% in 2004, 9.3% in 2005, and 10.4% in 2006.

The Venezuelan government then sought a greater share of revenue by forcing renegotiation of contracts and by nationalizing entire companies. In 2005, Venezuela gave foreign oil companies operating conventional oil fields 1 year to convert their service contracts into joint venture agreements under which PDVSA was to be granted the minimum 60% stake. In April 2006, after Total SA and Eni SPA refused to enter into the proposed JV agreements, the Venezuelan government seized the oil fields operated by those two companies. The remaining companies either sold their stakes or acceded to the government's demands.

Chavez set June 26 as the deadline for international oil companies to accept terms for the government to take a majority stake in four heavy-crude upgrading projects valued above $30 billion that produce 600,000 b/d of heavy oil from in the Orinoco reserve. That move is part of Chavez's nationalization drive that includes taking over US companies' assets in telecommunications and electrical power.

Four other international companies—Chevron Corp., Statoil AS, BP PLC, and Total SA—apparently accepted the accord that will keep them in the massive Orinoco projects.

Seeking more investment

Despite the expropriations, the Chavez government hopes to attract more than $21 billion in foreign investment to boost Venezuela's oil production to 5.2 million b/d by 2012, up from 2.4 million b/d currently. The fourth-largest producer among the Organization of Petroleum Exporting Countries, Venezuela plans to spend $77 billion over the next 5 years.

However, analysts say the nationalization program likely will disrupt those plans. Venezuela's oil production has fallen 25% since Chavez took office in 1999, largely as a result of the layoffs of more than 20,000 experienced PDVSA engineers and executives after they joined a 2002-03 strike to remove Chavez from office. ✦

'Blue Dog' energy plan counters House speaker's program

Nick Snow
Washington Correspondent

As she promised in January, US House Speaker Nancy Pelosi (D-Calif.) announced a wide-ranging energy legislation package on June 28. "With confidence in American ingenuity and high faith in our future, we Democrats declare America's independence from foreign oil," she said at a press conference with Majority Leader Steny H. Hoyer (D-Md.) and several committee chairmen.

Pelosi said House Democrats will return from their Independence Day recess prepared to debate bills that would invest heavily in biofuels and renewable energy sources, increase energy efficiency, press the Bush administration to combat climate change, and create "good green" jobs.

Critics said provisions that would substantially increase domestic energy production were missing from the package. Rep. John E. Peterson (R-Pa.) called independence from foreign oil "a worthwhile goal but far from realistic under this plan." He reintroduced a bill to increase gas production from the Outer Continental Shelf earlier in the week.

Pelosi's proposal, Peterson declared, "will make us more dependent on foreign countries for our energy, as she and much of this majority are rabidly opposed to any domestic energy production."

'Blue Dog' ideas

Two groups outside Congress said proposals offered by the Blue Dog Coalition of 47 House Democrats on June 27 were better than Pelosi's.

National Association of Manufacturers Pres. John Engler called them a welcome "break from the usual rhetoric." And Independent Petroleum Association of America Pres. Barry Russell suggested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that the Blue Dog Coalition "should steer the majority ship when it comes to crafting a substantive and comprehensive energy policy."

The fiscally conservative Blue Dog coalition of Democrats was formed in 1995 with an aim of representing the House's political center. Its core beliefs include a commitment to US financial stability and national security, according to a statement at the group's web site.

Reps. Jim Matheson of Utah and Charlie Melancon of Louisiana, both members of the House Energy and Commerce Committee, cochaired the Blue Dog Energy Task Force, which produced the eight principles dealing with energy production, climate change, fuel diversity, and technology development.

Matheson said the first principle applies the "pay as you go" concept to domestic energy. "America's energy policy cannot depend solely on a future technological breakthrough. We have diverse energy resources in America today, and we can't discard any of them. Until technology catches up, a reliable supply of conventional fuels is essential for our economy," he explained.

The principle states that US energy policy should not reduce access to domestic resources, domestic infrastructure, or incentives for domestic production unless there is a corresponding initiative to replace lost capabilities.

While renewable resources are increasingly contributing to energy supply, the Blue Dog Coalition considers oil, gas, coal, nuclear power, and other traditional sources key components of US energy supply.

'Reliable supply'

"In the long run, alternative fuels will provide a significant contribution to our country's energy profile," the group says. "Until that takes place, a reliable supply of conventional fuels will be important for our economy, and policies should be directed toward maintaining domestic conventional energy capabilities."

Other group principles address climate change (which the Blue Dogs believe should be handled with predictable long-term policies that don't disproportionately affect one industry or sector) and fuel diversity (which the group says should include biofuels, coal, geothermal, hydroelectric, nuclear, oil, and gas).

Heavy US reliance on foreign petroleum suppliers contributes to the country's balance of payments and distorts foreign policy by encouraging energy development in unstable regions, according to the Blue Dogs. They consider encouraging domestic exploration and production of petroleum "a responsible component of a national energy policy."

The group also considers renewable energy "the key to long-term energy security" and recommends that the federal government invest substantially to help develop wind, solar, biomass, fuel cells, and other sustainable energy technologies. "Congress should also extend the wind energy production tax credit to provide greater long-term market certainty," it says.

The Blue Dogs also call for consistent and transparent federal energy policies; keeping energy affordable with consistent rates and access to supplies; encouraging investments in electricity transmission systems, distributed generation, and a more efficient grid; promoting development of cleaner technologies with substantial federal investments in research; and encouraging adoption of more-efficient technologies to reduce consumption.

Support for principles

NAM's Engler said the Blue Dog Coalition's energy principles are "highly consistent" with his association's energy and economic security plan, which also supports domestic energy production, diversity, and technology development.

"When you restrict the domestic supply, it's only logical that prices will go up. Continuing down this path is not just bad policy, it's bad economics," he said.

IPAA's Russell said oil and gas currently represent about 65% of total US energy supplies and will continue to be significant as domestic demand grows by 30% by 2030. "Legislation that reduces the ability of American oil and gas producers to invest in the United States means higher costs for consumers and more dependence on foreign, often unstable, supplies. National energy policy needs to expand all of our energy resources, not pit one against another," he said.

Policies that support steady additions to domestic energy supplies are essential, American Petroleum Institute Pres. Red Cavaney said in a June 29 letter to members of the 110th Congress. "These policies ought to encourage development of every viable form of energy and more efficient use of each of them. However, an 'either-or' policy—one that favors alternative energy at the expense of oil and natural gas—is short-sighted and could end up harming both consumers and the economy," he said.

Two days before Pelosi's announcement, the House voted to renew a 26-year-old moratorium on new federal oil and gas leasing on the Outer Continental Shelf and make it part of the US Department of Interior's fiscal 2008 budget. ✦

US House votes to delay oil shale leasing, development

Nick Snow
Washington Correspondent

The US House voted June 27 to delay for at least a year oil shale leasing and development required under the 2005 Energy Policy Act (EPACT). It adopted an amendment proposed by Rep. Mark Udall (D-Colo.) to the US Department of Interior's fiscal 2008 budget that would bar the Bureau of Land Management from issuing any final regulations for commercial-scale oil shale leasing and from offering any commercial-scale oil shale leases.

Udall said EPACT currently requires BLM to issue the regulations and to move to leasing "on a crash basis and under a tight deadline." He proposed a similar amendment 2 weeks earlier as the Energy and Natural Resources Committee marked up HR 2337, the Energy Reform and Revitalization Act.

"Oil shale has potential as an energy source, but Colorado's Western Slope has had experience with a rush to development that ended up hurting our region's economy. My legislation will ensure that oil shale is developed in a responsible way," Udall said following the vote.

He said a 2005 Rand Corp. report, which had highlighted benefits of developing oil shale, also noted that large-scale development would significantly increase the area's population and put pressure on local communities to provide services.

Udall said many on Colorado's Western Slope oppose the timetable outlined in EPACT. He said they would rather see one in which DOI takes enough time to do the evaluation and leasing properly. "My amendment will slow that process down so that we can be thoughtful about oil shale development," he said.

Rep. Chris Cannon (R-Utah) disagreed. "On the very day that [Venezuelan President] Hugo Chavez took greater control of world oil supply, the House took a major step backward in the development of our very own sources of oil. Cowed by the environmental lobby, the majority today voted to put the plug back into one of the most promising and viable new sources of oil we have in the entire nation," he said following the vote.

Cannon said the Green River oil shale formation in Colorado, Utah, and Wyoming conservatively holds an estimated 2 trillion bbl of recoverable oil—enough to meet current US demand for 200 years or longer. "Development of diverse sources of energy is vital to our national security, and oil shale is an integral part of a comprehensive energy strategy," he said. ✦

New seismic data needed to make OCS decisions

Nick Snow
Washington Correspondent

Seismic data that are not several decades old are needed before the US Minerals Management Service's new 5-year plan for Outer Continental Shelf oil and gas leasing is acceptable, a House subcommittee chairman said as he opened a hearing on the plan.

"During debate on the House floor this week, it was said that 80% of the known resources on the OCS are available for drilling. I believe that's accurate, but I believe it's based on figures that are decades old," said Rep. Jim Costa (D-Calif.), who chairs the Natural Resources Committee's Energy and Mineral Resources Subcommittee. "That information needs to be updated."

Costa said too much of the debate on both sides of the aisle "has been focused on ambiguity, assumptions, and vigorously debated arguments," adding "We can have a more robust level of discussion with more-accurate-information."

Acting MMS Director Walter D. Cruickshank confirmed that MMS had to use seismic surveys shot in the late 1970s and early 1980s as it considered possibly including offshore Virginia in the 2007-12 OCS plan. He said MMS also considered seismic data from adjacent areas off Canada and the Bahamas, but said, "Until more work is done out there, it is not very good information," he said.

Companies that historically have supplied such information to the government aren't likely to pay for new surveys if an area is not going to be leased, Cruickshank said. "We don't do our own surveys. To do so for any given planning area would take $50-85 million and several years of processing. We have 26 planning areas, although there is more-recent data from places like the central and western Gulf of Mexico, where there has been oil and gas activity," he said.

New seismic data are needed because the technology has improved so dramatically in the last 25 years, said Rep. Stevan Pearce (R-NM), the subcommittee's chief minority member. "Back then, you got only a one-dimensional picture." he said.

Still off-limits

When Pearce asked Cruickshank if he thought companies would shoot new seismic surveys if OCS acreage off Virginia was removed from an existing congressional moratorium and presidential withdrawal, he said he thought that companies would. He added that MMS would not begin to prepare for a lease sale there while

the bans are in place.

Pearce said several members of New Jersey's congressional delegation have expressed concern over the possibility of a spill in the proposed leasing area off Virginia reaching their state's coast. "Currents running immediately offshore Virginia are southerly and, farther out, run straight out to sea. We believe the chances that a spill would reach New Jersey's coast are minimal," Cruickshank replied.

"Including Virginia in the 5-year plan will provide answers. It would be short-sighted not to seek them, as I believe the majority of Americans want to know how extensive our domestic resources are," said one witness, Rep. Thelma Drake (R-Va.), a former subcommittee member whose district includes much of Virginia's coast.

She and Virginia State Sen. Frank Wagner (R-Virginia Beach) separately noted that the state sought assurances in its energy plan that any federal leasing would take place an appropriate distance from shore. They criticized the new 5-year plan because it gives the state a much smaller potential federal leasing area because of Virginia's concave coast.

But Drake reiterated that it's important to learn just how much natural gas is out there. "All the renewable energy we could produce won't keep our homes warm and our lights on. We must allow MMS to determine how extensive our OCS resources are," she maintained.

Not every Virginian supports OCS leasing off the state's coast. Albert Pollard, a former member of Virginia's house of delegates, told the subcommittee that outside the Virginia Beach region in Wagner's district, the state has the largest coastal pristine acreage on the eastern seaboard. Production from offshore leases would not occur for at least 10 years, he added. ✦

MMS royalty in-kind program exceeds revenue goals

Nick Snow
Washington Correspondent

The US Minerals Management Service's crude oil and natural gas royalty in-kind program continued to exceed its goals during fiscal 2006, reported the Department of the Interior June 28. Financial returns increased, administrative costs decreased, and compliance cycles shortened, it said in an annual report delivered to Congress a day earlier.

The RIK program is now in its third year of full operation, said acting MMS Director Walter D. Cruickshank. He said the program generated $26.2 million more in revenues during the year than what would have been received if the government had taken its royalties "in value," as cash payments from producers. Combined with a $2.6 million gain from additional interest on RIK revenue received 5-10 days earlier than under a royalty in-value program, additional revenue was $28.8 million during fiscal 2006, Cruickshank said.

This followed $32 million of additional revenue in fiscal 2005 and $18 million more in fiscal 2004. With the fiscal 2006 increase, federal revenue under the RIK program has been more than $78 million above what it would have been under an RIV system, the MMS official said.

Under the RIK program, the federal government takes its oil royalties "in kind" as product, which is then sold competitively on the open market. MMS received and sold nearly 75.3 million boe in kind, valued at more than $4 billion, during fiscal 2006, the agency said. The Gulf of Mexico remains the core source for RIK crude, it added.

The program has drawn fire from House Natural Resources Committee Chairman Nick J. Rahall (D-W.Va.), who noted during a May 23 hearing on HR 2337—the Energy Reform and Revitalization Act—that the US Department of Justice is investigating the operation. MMS subsequently said DOJ's inquiry came in response to findings by DOI's inspector general. The bill, which the committee approved in mid-June, includes a provision that would limit RIK payments to crude used to refill the Strategic Petroleum Reserve.

Cruickshank said that by the end of fiscal 2006, MMS took in kind about 72% of the crude oil and 45% of the natural gas royalty volumes produced daily in the gulf. The agency began taking gas in kind for federal production in Wyoming in April 2006 at the rate of 30,000 MMbtu/day, he added.

MMS and the US Department of Energy also will use the RIK program to begin filling the SPR during July, with an initial 50,000 b/d from the crude oil portfolio, Cruickshank said. MMS will continue to use RIK sales in tandem with RIV payments, depending on the particular business case, to ensure a fair return on federal royalty assets, he said. ✦

COMPANY NEWS

Linn Energy to buy Dominion's US Midcontinent E&P assets

Linn Energy LLC agreed to buy certain natural gas and oil exploration and production operations in the US Midcontinent from Dominion for $2.05 billion.

These operations, primarily in Oklahoma, include reserves of 780 bcf of proved gas equivalent as of Dec. 31, 2006. The transaction is expected to close by the end of the third quarter.

Separately, Houston independent Tammany Oil & Gas LLC has acquired the Gulf of Mexico shelf divestment package from Dominion Oklahoma Texas Exploration & Production Inc., a subsidiary of Dominion. The purchase price was not disclosed.

In other recent company news:

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Chavez courts Russia, Iran

Venezuelan President Hugo Chavez returned home last week, fresh from visits that sought to strengthen political ties with fellow oil producers Russia and Iran.

In Moscow on June 28 Chavez said that Russia and Venezuela "remain strategic partners in energy." He went on to add, "Lukoil already operates in our country, which chagrined President Bush."

He also said, "We are thankful to Russian and other foreign companies, which remained in our country in contrast to US companies that left the Venezuelan market." Left the Venezuelan market? Ooh! Tell us another one, Hugo.

They didn't leave; he pushed them out. Last February, Chavez ordered exploration by international companies to be run under joint ventures with local companies. He even set a minimum stake of 60% for the local players.

Whistlin' Dixie

Needless to say, one or two international oil companies found that change a bit unfair and—more to the point—highly unprofitable, especially as Chavez also increased their tax rates.

Warming to this theme, Chavez thanked Russia for its position on oil pricing. "Oil prices were in jeopardy some time in the past; it was sold for a song," said the Venezuelan president, who must have been whistlin' Dixie back in the day.

This time, though, Chavez was just blowing smoke, suggesting that his country might begin to develop a nuclear power industry. "Who knows, maybe, Venezuela will head in this direction," he wheezed. That was doubtlessly another way of rattling Washington.

Meanwhile, he said, "We need a strong and strengthening Russia." The president stressed that Caracas "does not want war but wants peace." He insisted that "if the US dares to invade Venezuela…we are ready to fight and die for the freedom of our homeland." Sure.

Diesel subs

While awaiting the day when he can command a nuclear arsenal, Chavez discussed possible purchases of diesel submarines and other defense equipment from Russia, arguing that these are needed to defend his oil-rich country against the US.

Before heading on to Iran, Chavez met Russian President Vladimir Putin and Belarus counterpart Alexander Lukashenko and urged the two leaders in joining a global revolution against Washington.

He had the same to say in Iran, telling Iranian President Mahmoud Ahmadinejad that the two oil-producing states, which have forged close ties in opposition to the US, should cooperate to defeat imperialism.

"Cooperation of independent countries such as Iran and Venezuela has an effective role in defeating the policies of imperialism and saving nations," said Chavez, who backs Iran's nuclear program, which is under United Nations sanctions.

Ahmadinejad, whose country is embroiled in a standoff with the West over that program, took up the theme, saying, "The pillars of the global arrogance have become shaky." But short of mobilizing his country's cadres in a march against Washington, Ahmadinejad said "victory" could be achieved "with resistance and standing firm." ✦

- McMoRan Exploration Co. agreed to buy all of Newfield Exploration Co.'s producing properties in the shallow-water Gulf of Mexico for $1.1 billion and the assumption of liabilities associated with future abandonment of wells and platforms. The sale is expected to close this month.
- Cal Dive International Inc. and Horizon Offshore Inc. have signed a definitive merger agreement under which Cal Dive will acquire all of the outstanding shares of Horizon in a stock and cash deal valued at $650 million. The price includes $22 million of Horizon's net debt as of Mar. 31.
- BP PLC and TNK-BP have signed a memorandum of understanding with Russia's OAO Gazprom to jointly invest in major long-term energy projects or swap global assets, the companies said.
- Oneok Partners LP has agreed to pay $300 million to buy Kinder Morgan Energy Partners LP's North system, which comprises a 1,600-mile interstate pipeline that delivers natural gas liquids and products from Kansas to Chicago.
- Murphy Oil Co. Ltd., a wholly owned unit of Murphy Oil Corp., has acquired the interests of Bear Ridge Resources Ltd. for $155 million (Can.). Bear Ridge's assets lie in the Tupper area in British Columbia, an undeveloped Montney natural gas play.
- Compton Petroleum Corp. plans to buy Stylus Energy Inc. for $91 million (Can.), or $2.70/share, including the assumption of $12 million in net debt. Both companies are based in Calgary.
- North Peace Energy Corp. has increased its stake in certain oil sands leases in north-central Alberta's Red Earth area through the acquisition of Peace Oil Corp.'s interest in the Red Earth leases for $20 million (Can.) in cash and stock. Peace Oil is North Peace's joint venture development partner in the Red Earth leases.

Dominion assets sold

Last year Dominion, a Richmond, Va.-based electric and gas utility, announced plans to divest its E&P operations except for 1 tcf of estimated proved gas reserves in the Appalachian basin (OGJ, June 11, 2007, p. 32).

With the Linn transaction, Dominion now has sold or agreed to sell all the operations that it plans to divest. All other previously announced E&P sales have closed or are scheduled to close by that time.

Dominion wants to focus on its businesses in electric power generation, gas distribution, transmission, storage, and retail marketing.

Meanwhile, the asset package acquired by Tammany contained properties in state and federal waters across the gulf, both operated and nonoperated.

A Tammany spokesman called the assets "a mixed bag." The deal was small compared with Dominion's previously announced divestitures, he said, adding that he could not discuss details yet because of a confidentiality agreement with Dominion.

McMoRan in the gulf

McMoRan's transaction also provides the New Orleans-based independent with interest in Newfield's ultradeep-shelf acreage in its Treasure Island and Treasure Bay exploration program. Newfield will retain a 10-25% working interest in the Treasure Island and Treasure Bay acreage, which encompasses 85 lease blocks.

David A. Trice, Newfield chairman, president, and chief executive officer, said the sale is the first in a series of planned divestitures that also include assets in China's Bohai Bay, the North Sea, and Texas and Oklahoma.

Newfield, Houston, will continue to focus on growing its deepwater portfolio in the gulf, Trice said. Newfield also will continue to explore and drill shelf prospects, he said.

Current net production from the properties being sold is 270 MMcfd of gas equivalent. Newfield's net production from its shelf properties in the first half of this year is expected to be 46 bcf.

Upon closing, McMoRan will assume operatorship of the Treasure Island lease. In addition, McMoRan will join Newfield in a 50-50 joint venture on Newfield's shelf primary-term lease acreage. This venture will cover 19 blocks, or nearly 100,000 gross acres.

Treasure Island is believed to have potential for several trillion cubic feet of recoverable gas in Miocene and older sections.

Cal Dive-Horizon deal

The combined Cal Dive and Horizon Offshore will operate a fleet of 23 diving support vessels, seven pipelay and pipebury barges, one dedicated pipebury barge, one multiservice vessel, one combination derrick-pipelay barge, and two derrick barges.

The boards of Cal Dive and Horizon unanimously approved the transaction. Closing of the deal, expected in the third quarter, is subject to regulatory approvals and other customary conditions, as well as Horizon

PERSONNEL MOVES AND PROMOTIONS

Aztec Oil & Gas elects CEO and chairman

Aztec Oil & Gas Inc. has elected **Franklin C. Fisher Jr.** chief executive officer and chairman, effective July 15.

Fisher has served as an advisor to Aztec since its inception.

Before his appointment, he worked mainly as a strategy consultant for various businesses. Before that he was chairman of Ashford Bank-MBank Memorial, which experienced substantial growth and was later profitably sold to Mercantile Bank.

Fisher's career began in 1964 when he joined a small steel fabrication firm in Houston and, subsequently, bought control of the company after 2 years. He then became involved in various enterprises, and several of his firms operated in multiple foreign countries. Fisher has sold most of his construction and manufacturing holdings.

Other moves

Trans-Orient Petroleum Ltd., Vancouver, BC, has appointed **David Bennett** executive chairman.

Bennett, a 30-year industry veteran, is a cofounder of Austral Pacific Energy Ltd., where he was chief executive officer from 1997 to 2005.

Bennett was responsible for the Douglas-1 gas-condensate discovery in the Papua New Guinea foreland and led the team that discovered Ngatoro oil field and Kupe South gas-condensate fields in New Zealand.

Bennett said research indicates that the Selandian Waipawa and Maastrichtian to Danian Whangai fractured shales on Trans-Orient's permits in the New Zealand East Coast basin are "excellent candidates for oil and gas production."

Australia's BHP Billiton Group announced **Marius Kloppers** would succeed **Chip Goodyear** as chief executive officer effective Oct. 1. Goodyear plans to retire as chief executive on Sept. 30.

Kloppers currently is group president, nonferrous materials, and an executive director. Previously, he served as chief marketing officer and chief commercial officer.

Kloppers will be based at BHP's headquarters in Melbourne.

Louisiana Offshore Oil Port LLC (LOOP) has appointed **Thomas L. Shaw** president.

Shaw, an executive and professional engineer with 30 years of experience in the pipeline industry, succeeds **Robert C. Thompson**, who is retiring after more than 22 years.

Since 2005 Shaw has served as vice-president of operations for LOOP. Before that, he served as a vice-president of Marathon Oil Corp.'s pipeline organization, with engineering, procurement, construction, operations, and maintenance experience in Marathon's pipeline and refining organizations.

LOOP is jointly owned by Marathon 50.7%, Royal Dutch Shell PLC 46.1%, and Murphy Oil Corp. 3.2%. It is the nation's only deepwater offshore oil port capable of receiving supertankers for offloading of oil cargoes. LOOP expedites the delivery of over 1.5 million b/d of imported and US crude.

Stone Energy Corp. has appointed **Richard L. Smith** vice-president of exploration and business development. Smith will assume his role in late July.

Smith joins Stone Energy from Dominion E&P Inc., where he currently serves as general manager of deepwater Gulf of Mexico exploration.

Smith previously worked for Exxon Corp. and Texaco USA.

stockholder approval.

Following the transaction, Quinn Hebert will continue to serve as president and chief executive officer of the combined company and the Cal Dive board will be expanded to include two Horizon directors for a total board of eight members.

The combined company will continue to be based in Houston.

BP, TNK-BP asset swap

BP and TNK-BP said the recent move is "designed to extend Gazprom's access to international markets and deepen BP and TNK-BP involvement in Russian oil and gas." The companies will establish a joint team to "identify strategic opportunities for investment both overseas and inside Russia," they said.

Initially, the joint company team will look for projects of at least $3 billion in cost, said BP Chief Executive Tony Hayward. Hayward said the companies would immediately set up a joint steering group to look for suitable investment options "across all geographies."

As part of the MOU agreement, TNK-BP has agreed to sell Gazprom its 62.89% stake in Rusia Petroleum OJSC, the company that holds the license for Kovykta gas field in Eastern Siberia. Kovykta field lies 450 km from Irkutsk in the north of the Irkutsk region. The field has estimated resources of 2 trillion cu m of gas in place, TNK-BP said.

Also based on the MOU, TNK-BP will sell its 50% interest in East Siberian Gas Co., which is building the regional gasification project. Gazprom has agreed to pay $700-900 million, subject to adjustments, for both sets of interests.

Gazprom and TNK-BP also agreed to a longer term "call" option for TNK-BP to purchase a 25% plus one share stake in Kovykta at an independently verified market price. This option could be exercized "once a joint investment or asset swap has been agreed under the terms of the MOU," the companies said.

Gazprom is Russia's largest company and the world's largest producer of natural gas. It holds about one quarter of total world gas reserves. Gazprom exports gas to 32 countries within and beyond the former Soviet Union. In 2005 the company sold 156.1 billion cu m of gas to European countries and with 76.6 billion cu m to the Commonwealth of Independent States and Baltic states.

TNK-BP, the third largest oil company in Russia, is owned and managed jointly by BP and Alfa Access Renova Group.

Oneok buys pipeline system

Also included in Oneok's acquisition are Kinder Morgan's 50% ownership interest in the Heartland Pipeline Co., seven propane truck-loading terminals along the North system, and one multiproduct terminal complex in Morris, Ill.

The transaction, which is to close in the third quarter, is expected to be accretive to distributable cash flow to Kinder Morgan unitholders.

Murphy-Bear Ridge deal

In April Bear Ridge reported the successful drilling and casing of its fifth Tupper Montney test well at a-23-B/93-P-9. This well extended the Tupper Montney reservoir trend to the southwest with "increasing pay thickness," the company said.

The a-23-B well found the thickest pay interval of the company's five wells drilled to date in the area, reconfirming Bear Ridge's geological and geophysical model, which supports an estimated 800 bcf of original gas in place on the company's land block.

Compton-Stylus deal

The boards of Compton and Stylus have unanimously approved the transaction, which remains subject to certain conditions including approval by two thirds of Stylus shareholders. The acquisition is expected to be completed by Aug. 15, subject to regulatory approvals. Stylus, which has oil and natural gas operations in Alberta, will pay Compton $2 million if the deal does not close.

As of June 1, Stylus reported 2,677 million boe of proved reserves, 4,038 million boe of proved plus probable reserves, and production of 2,000 boe/d.

North Peace-Red Earth

North Peace has closed an agreement with Peace Oil and Peace Oil's indirect parent company, Surge Global Energy Inc. This includes a commitment to issue $5 million (Can.) of common shares, which will be subject to a contractual 1-year hold period.

Upon closing, North Peace's holdings in the Red Earth leases will increase to 100% interest from 70%.

The company recently reported that it is confident about the commercial potential of the leases in the Red Earth area, and it has confirmed that plans for a cyclic steam stimulation pilot project are advancing as scheduled, with the first steam cycle expected in late 2008 or early 2009. ✦

CHINA THRUST BELT EXPLORATION—1

Oil discovery revives China foreland basin after long lull

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Located in the northern edge of the Qilian Mountain fold belt in western China, the Jiuxi basin is a Mesozoic-Cenozoic foreland basin with Lower Cretaceous source rocks and Tertiary-Cretaceous reservoirs.

This is the first of two parts on the course of exploration and a relatively recent discovery that has implications for broader exploration in foreland basins and thrust belts elsewhere.

The Jiuxi basin is small but has 67 years of exploration history.

Five Tertiary anticline oil fields had been found in the foreland thrust belt at the southern margin of the basin with oil in place of 61.61 million tons from 1950 to 1960 and a peak production of 1.4 million tons in 1959. Since then, no discoveries were been made until the late 1990s, and production gradually declined to 0.4 million to 0.6 million tons/year.

In 1983, exploration turned to the source depression, i.e. the Qingxi Depression, and oil discovery peaked in the Jiuxi basin. In 1998 a high oil flow from the Lower Cretaceous was encountered in test well Liu 102 in the Liugouzhuang structure; and Qingxi field, the largest in the basin, was found. Since the discovery, 41 wells have been drilled, proved reserves have reached 58 million tons, and the basin's production is 80 million tons/year.

The discovery of Qingxi field in the Jiuxi basin is an example of successful exploration in foreland thrust belts. The key factors for the success include deepened geological understanding, improved seismic imaging in hilly areas, better identification of reservoirs, and good reservoir stimulation. This success provides hope for finding new oil and gas fields in other foreland basins, especially their thrust belts, in central and western China.

The case study of the Qingxi field discovery in this article sheds light on future hydrocarbon exploration in thrust belts of foreland basins in China and other parts of the world.

Introduction

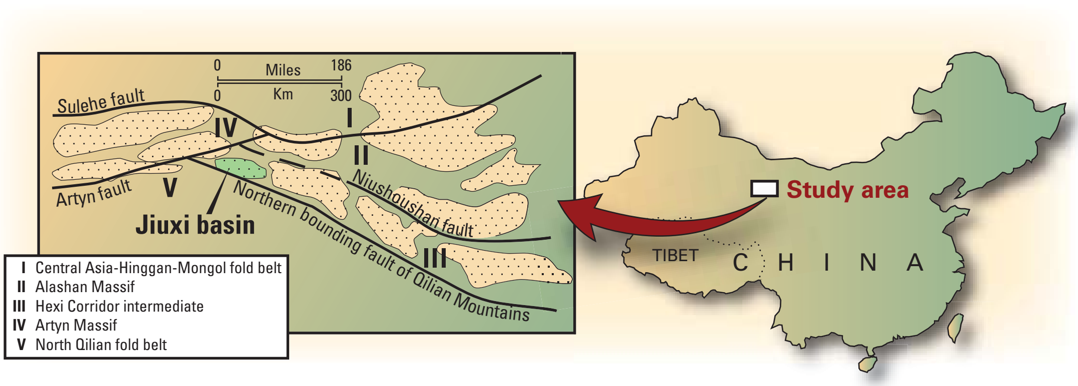
Foreland basins and their thrust belts are some of the world's most petroliferous areas with a great hydrocarbon exploration potential.[1]

Mann and Gahagan[2] classified six kinds of tectonic settings according to the evolution history of hydrocarbons and found that, among 595 giant oil and gas fields with reserves over 500 million bbl or equivalent gas, 141 are in collisional margins produced by terminal collision between two continents, and 44 are in collisional margins produced by overthrusting of volcanic arcs onto a passive margin. Pettingill[3] showed that 58% of 76 giant fields discovered in 1990-99 are in collisional tectonic settings, including fold belts, foreland, and foredeep.

The multiple stages of tectonic evo-

WESTERN CHINA'S JIUXI BASIN

Fig. 1

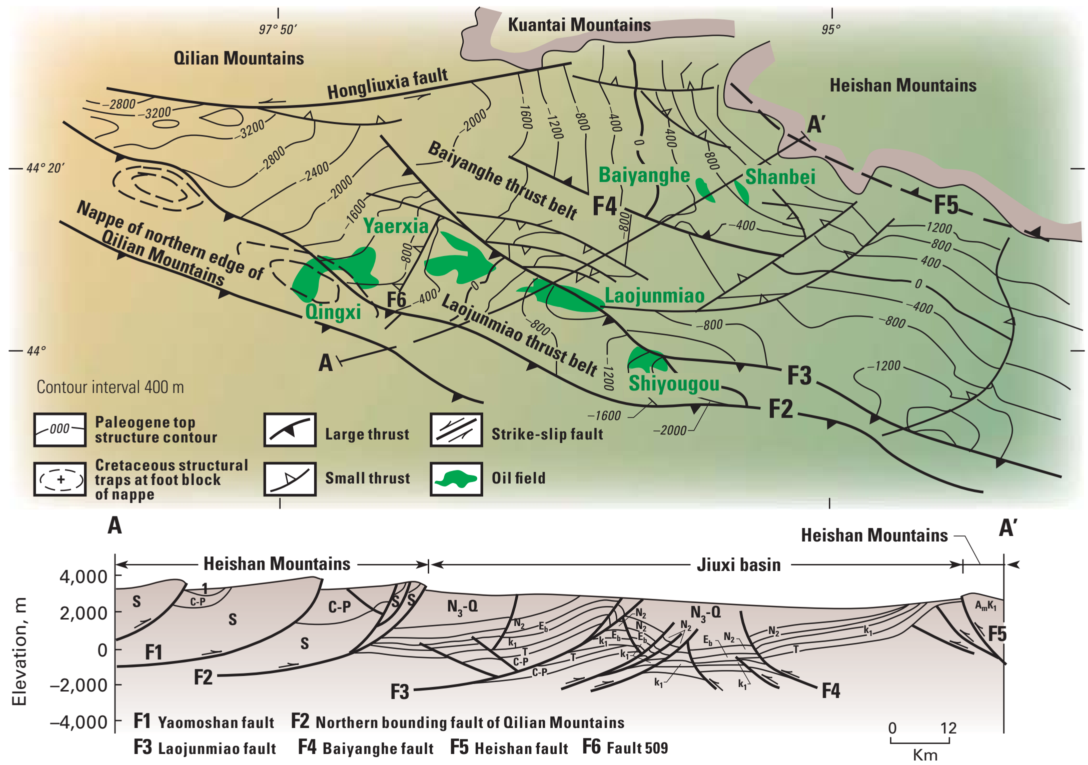


lution and multiple successions of source rocks in foreland basins are the principal geological factors for abundant hydrocarbon resources. The application of modern technology is critical to making a great discovery. For example, a suite of new and-or improved technologies in seismic data acquisition, processing, and interpretation, drilling and well completion, and stimulation of low permeability reservoirs, made the Greater Rocky Mountain Region the "garden" for exploiting previous big discoveries in the 1990s.[4] Improved seismic technology, especially deep seismic imaging, plays a great part in big discoveries.

Petroleum exploration in foreland basins and their overthrust and fold belts in west and central China has a long history.[5] During the 1950s and 1960s, exploration focused on clearly identified surface anticlines in foothills and depressions with many surface oil leakages, and

Structure map on top of Paleogene

Fig. 2



See Fig. 3 for explanation of stratigraphic symbols

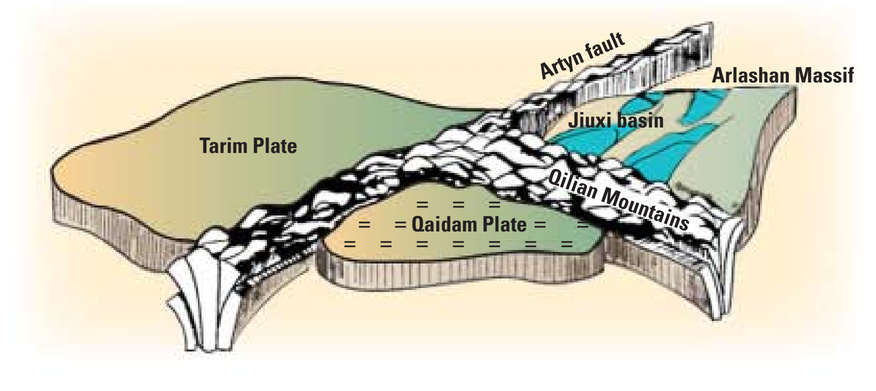
Jiuxi basin summary chart

Fig. 3

Age	Formation	Symbols	Thickness m	Lithology	Sedimentary facies	Source rock (TOC, % 1 2 3 4; R°, % .5 1)	Tectonic movement	Basin evolution
Quaternary		Q	656		alluvial fan		Himalayan movement II	foreland basin
Neogene		N3	1,900		fluvial lacustrine			
		N2						
		N1						
Paleogene	Baiyanghe	E3b	600		fluvial lacustrine		Himalayan movement I	
	Huoshaogou	E2h	1,200		alluvial fa fluvial			
	Liugouzhuang	E1l	100		fluvial		III	
Lower Cretcaceous	Zhonggou	K1z	600		fluvial delta lacustrine		II	pull-apart basin
	Xiagou	K1x	1,400		fluvial		Yanshanian movement	
	Chijinpu	K1c	1,800		fluvial lacustrine fluvial			
Middle-lower Jurassic		J1-2	1,100		fluvial lacustrine		I	
Middle-lower Triassic		T2-3	1,000		fluvial	Trendline of vitrinite reflectance	Indosinian movement	folded basement
Paleozoic	Permian Carboniferous	C-P	>1,000		fluvial swamp			
		D						
	Silurian	S	15,000					

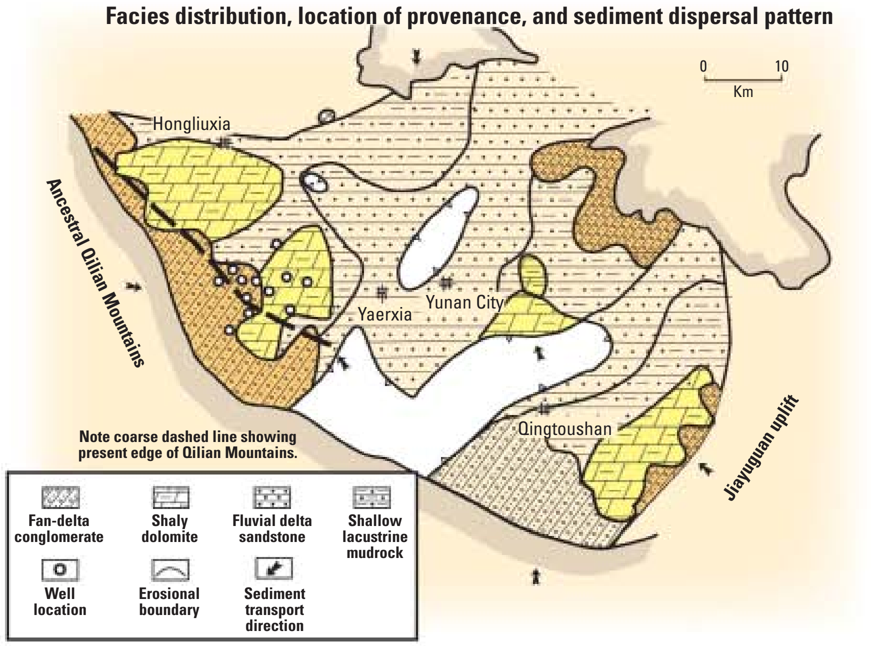
TECTONIC SETTING IN JIUXI BASIN PULL-APART STAGE

Fig. 4



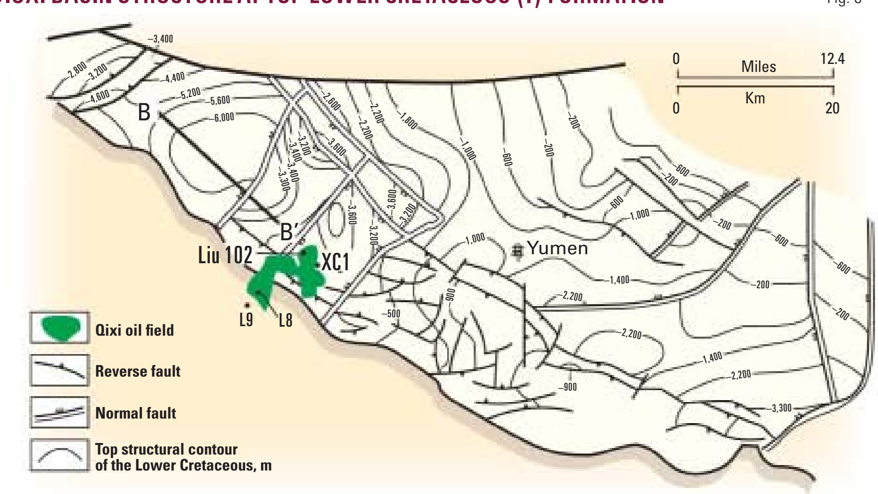
JIUXI BASIN EARLY CRETACEOUS PALEOGEOGRAPHY

Fig. 5



JIUXI BASIN STRUCTURE AT TOP LOWER CRETACEOUS (?) FORMATION

Fig. 6



many small and medium-sized oil fields were discovered.

In the 1990s, improved hilly seismic technology and drilling and well-logging technology under complex geological conditions (e.g., complex structures and high temperature and abnormal formation pressure) enabled discovery of a group of oil and gas fields in foreland regions, which increased reserves dramatically.

In the late 1990s, Qingxi field was discovered after 67 years of exploration in the mature Jiuxi basin. It is a great example of successful exploration in Chinese foreland basins and shows the great potential of hydrocarbon discoveries in many other thrust belts in west and central China. The success also demonstrates that good geological understanding and wise application of new technology can make great discoveries in mature foreland regions.

Basin evolution and petroleum system

Tectonics

The Jiuxi basin is located in the Hexi Corridor, northwestern China, bounded by the Alashan landmass in the north, Qilian Mountains in the south, Jiayuguan uplift in the east, and Arkin strike-slip fault belt in the west (Fig. 1).[6]

It is one of the Mesozoic-Cenozoic foreland basins along northern front of the Qilian Mountains and covers 2,700 sq km (Figs. 1 and 2).

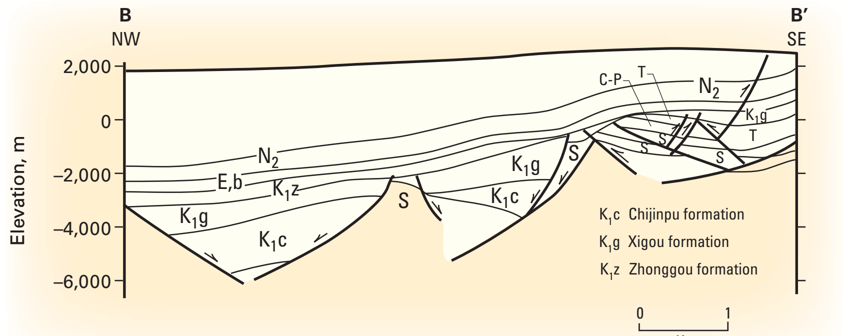
Stratigraphy

The Jiuxi foreland basin developed overlying a pre-Jurassic folded basement. Basin fill consists of Carboniferous, Permian, Lower-Middle Triassic, Lower-Middle Jurassic, Lower Cretaceous, Tertiary, and Quaternary, dominantly nonmarine deposits (Fig. 3).

The basement of folded and metamorphosed Lower Paleozoic rocks consists of extremely thick marine deposits.[7] The Devonian contains mainly purplish red fluvial sandstones and conglomerates, and some continental

JIUXI BASIN INCOMPLETELY INVERSED LOWER NORMAL FAULTS

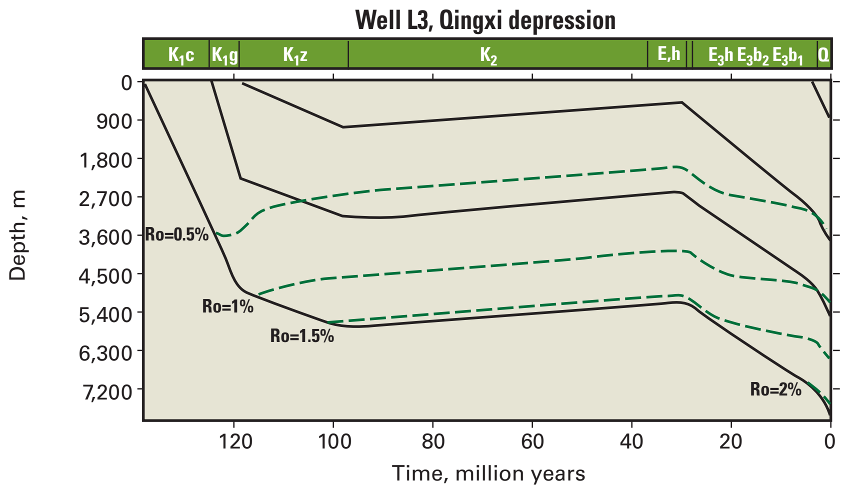
Fig. 7



See Fig. 6 for section location and Fig. 3 for key to stratigraphic symbols.

BURIAL HISTORY AND SOURCE ROCK MATURATION

Fig. 8



andesite and basalt that are also folded.

The Lower-Lower Carboniferous and Permian consist of about 1,000 m of transitional marine-nonmarine deposits mainly of sandstone with limestone and coal that were deposited in the marginal foreland basin settings after the Early Paleozoic ocean was closed.[8]

The Middle and Lower Triassic contain 1,000 m of fluvial-deltaic and lacustrine sandstone, siltstone, mudstone, and coal.[9]

The Middle and Lower Jurassic contain up to 1,100 m of fluvial-lacustrine pebbly sandstone, mudstone, and coal and are mainly at the piedmont side of the basin.

The Lower Cretaceous contains mainly alluvial and lacustrine deposits of upward Chijinpu, Xiagou, and Zhonggou formations. The Chijinpu formation has mainly sandstone and conglomerate in the lower part, dark gray mudstone in the middle part, and interbedded sandstone and mudstone in the upper part. Lateral facies changes are common in the Xiagou and Zhonggou formations.[10]

On the basin margin, purplish red sandstone, conglomerate, and mudstone are dominant and form one of the main oil reservoirs. Dark-gray mudstone, dolomitic mudstone, and black mudstone are in the central part of the basin as the key source rocks.

The Paleogene strata are dominantly fluvial-lacustrine purplish red mudstone and brownish red sandstone-conglomerate up to 2,000 m thick that were interpreted as being deposited in an arid climate.

The Neogene strata are primarily grayish white fluvial and lacustrine sandstones intercalated with brownish red mudstone. The Quaternary deposits are mainly piedmont conglomerates.

Basin evolution

In reference to basin type and evolution, formation of the Jiuxi basin has undergone three stages (Fig. 3).

Stage of basement formation. The northern Qilian oceanic basin underwent convergence closure at the end of the Caledonian Orogeny to form the northern Qilian orogenic belt was amalgamated with the northern Alashan landmass. Together they formed the folded basement for the overlying Mesozoic-Neozoic basins in the Hexi Corridor.

During Early and Middle Devonian, piedmont molasses were deposited on the edge of the northern Qilian fold belt. During Carboniferous and the earliest Permian, a mixed marine-nonmarine coal-bearing succession was deposited associated with an extensive marine transgression.

After a hiatus, typical continental clastic rocks were deposited during the Early-Middle Triassic. Thereafter, Upper Triassic was absent probably due to regional uplift associated with the Indosinian Orogeny.

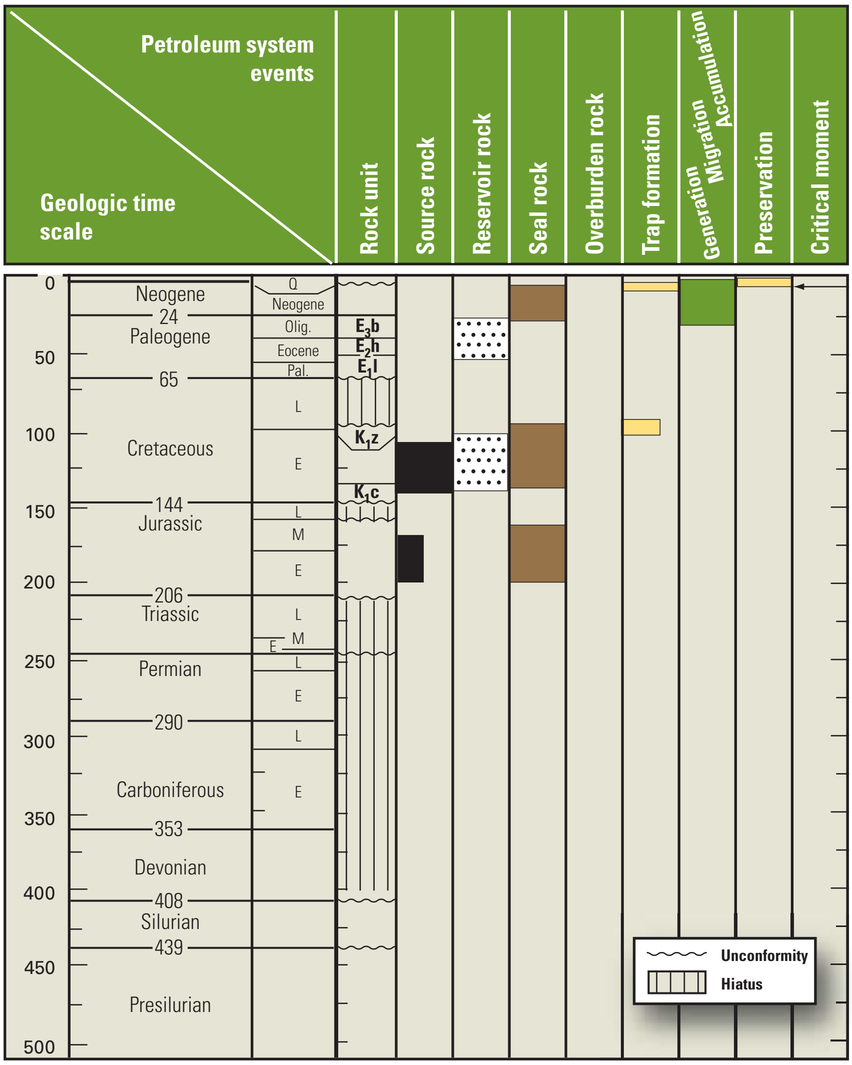
Stage of pull-apart and rift basin. The amalgamation of the Qinghai-Tibet Plate with the Northern China Plate in Jurassic and Early Cretaceous caused the northeastern movement of both the Qilian fold belt and the Alashan Massif via strike-slipping along the Arkin fracture.[6]

A more rapid eastward movement of the Alashan Massif caused a clockwise transtensional movement at the joint between the Qilian fold belt and the Alashan Massif, resulting in sets of NE-oriented fractures and transtensional rift basins[11] (Fig. 4). Depocenters at both the northern and southern ends of the rift basins were filled with lacustrine facies.

Outcrop data indicate that the Middle-Lower Jurassic Longfengshan

JIUXI BASIN SILURIAN-PALEOGENE PETROLEUM SYSTEM

Fig. 9



See Fig. 3 for key to stratigraphic symbols.

Group overlies unconformably the Middle-Lower Triassic Xidagou formation. The Yanshan Orogeny started at the end of Middle Jurassic and deformed pre-Cretaceous strata through faulting and folding.[12] The Middle-Lower Jurassic strata are sparsely present in the basin probably due to strong folding and erosion.

The major northern fault of the Qilian Mountains was overthrust towards basins during this stage.[13] At the Early Cretaceous, the transtensional movement formed a NE-trending half-graben basin with a faulted margin in the east and a ramp margin in the west. The Lower Cretaceous strata are 3,000-5,000 m thick (Fig. 5).

Fan delta conglomerate and sandstone were deposited at the basin margin and lacustrine shale, micritic limestone, and shaly dolomite in basin center.[10] During the Early Cretaceous, the rift basins experienced three phases: early rapid rifting, middle slow rifting, and late drifting, corresponding to deposition of the Chijinpu, Xiagou, and Zhonggou formations. Upper Cretaceous and Paleocene deposits are absent probably because of concurrent regional uplift.

Stage of foreland basin and thrust belts. Foreland basins formed in the piedmont areas due to intense uplift of the Qilian Mountains and northward compression from the latest Eocene to Oligocene,[14] and 1,900 m of clastic rocks were deposited.

The Huoshaogou formation is a succession of interbedded alluvial brownish red conglomerate and fluvial and lacustrine sandstone and mudstone deposited in an arid climate.

The Baiyanghe formation consists principally of brownish red interbedded mudstone and conglomerate-sandstone.

The Pliocene consists of 1,000-2,000 m of dominantly fluvial and lacustrine conglomerate, sandstone, and mud rock deposited in an arid climate. Faulting and thrusting intensified at the northern edge of the Qilian Mountains at the end of Pliocene due to the distal effect of the collision between the Indian and Asian plates and the uplifting of the Qinghai-Tibet Plateau, resulting in the formation of large thrust and nappe structures.

Both the sedimentary cover and basement were being involutedly deformed, becoming parts of the nappe at the northern edge of the Qilian Mountains. In this stage, the structural style in the basins had basically patterned. The northern Qilian orogenic belt has been

DATA OF CRETACEOUS SOURCE ROCKS, JIUXI BASIN

Table 1

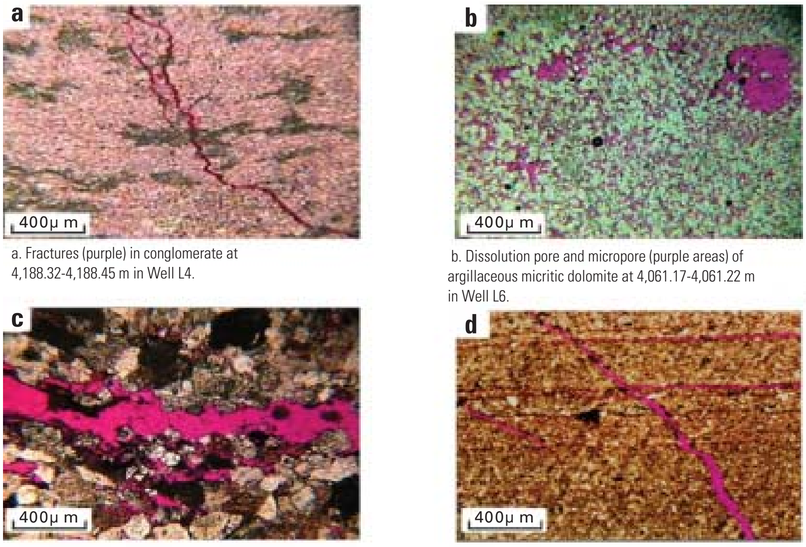
Stratigraphic intervals	TOC, % Range	TOC, % Average	Rock Ev, mg/g Range	Rock Ev, mg/g Average	Bitumen A, ‰ Range	Bitumen A, ‰ Average	Total hydrocarbon, % Range	Total hydrocarbon, % Average
Zhonggou fm	0.29-1.70	*0.78(87)	0.05-8.88	0.01(61)	0.02-2.03	0.37(35)	0.03-1.15	0.24(30)
Xiagou fm	0.18-3.33	1.35(134)	0.10-23.32	6.70(134)	0.08-5.00	1.59(59)	0.04-3.90	0.92(59)
Chijinpu fm	0.12-7.18	1.75(211)	0.06-54.80	7.70(96)	0.02-3.30	0.59(111)	0.02-2.10	0.49(73)

*Numbers in parentheses are numbers of samples.

CHARACTERISTICS OF FRACTURES AND DISSOLUTION PORES

Fig. 10

Photomicrographs of Jiuxi basin reservoir rocks



a. Fractures (purple) in conglomerate at 4,188.32-4,188.45 m in Well L4.

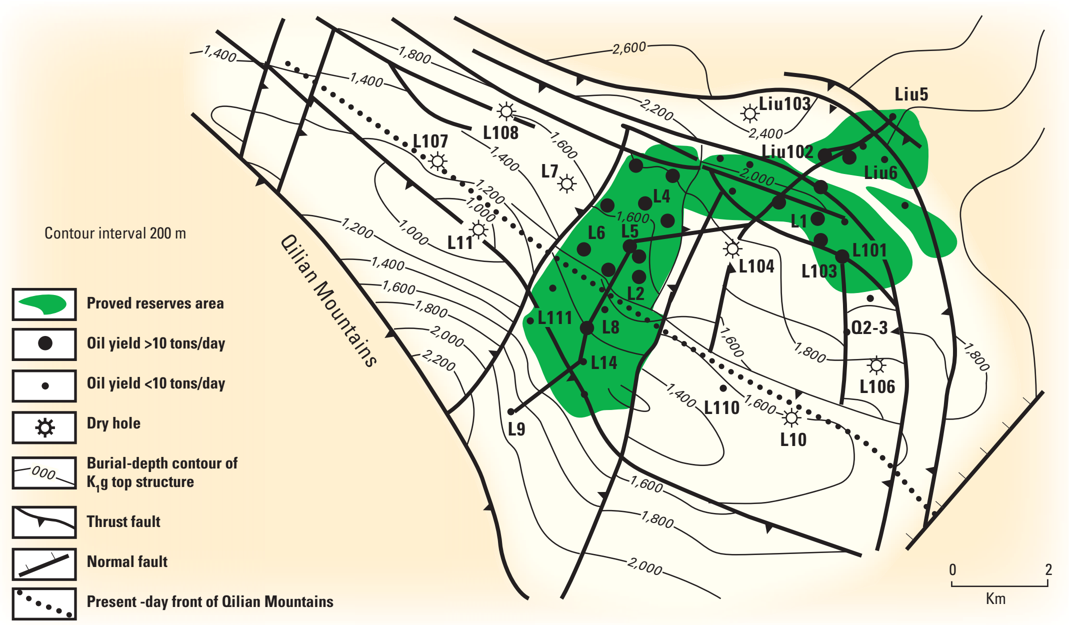
b. Dissolution pore and micropore (purple areas) of argillaceous micritic dolomite at 4,061.17-4,061.22 m in Well L6.

c. Fractures and interparticle pores (purple areas) in fine-grained sandstone at 3,737.10-3,737.11 m in Well L8.

d. Fractures (purple) 10-25 μ m wide at 4,131.38-4,131.50 m in Well L102.

STRUCTURE AT TOP OF CRETACEOUS XIAGOU FORMATION

Fig. 11



rapidly uplifted, and pluvial facies has been deposited in the basins during the Quaternary.

The sedimentary fill in the Jiuxi basin can be divided into two structural units (Fig. 6). The lower unit features NE-trending normal faults in the Jurassic-Cretaceous.[11] The Himalayan compression partially inversed the normal faults. However, as for most boundary faults of transtensional rift basins, the inversion was incomplete.

At present, the faults remain to be normal faults (Fig. 7) or "normal fault in the lower part and reverse fault in the upper part." The upper structural unit features NW-trending thrust faults and fault-related folds, forming an imbricated thrust system, which consists of the piedmont nappe structural belt in front of the northern Qilian Mountains in the south, the Laojunmiao thrust and fold belt in the middle, and the Baiyanghe thrust belt in the north (Fig. 2).

Petroleum system

Source rock. Dark gray and gray lacustrine shaly dolomite and dolomitic shale of the Lower Cretaceous Xiagou and Chijinpu formations are the source rocks in Jiuxi basin.[15-17] They are mainly in the Qingxi Depression and thicken from 2,400 m at basin margin to 3,200 m at depocenter.

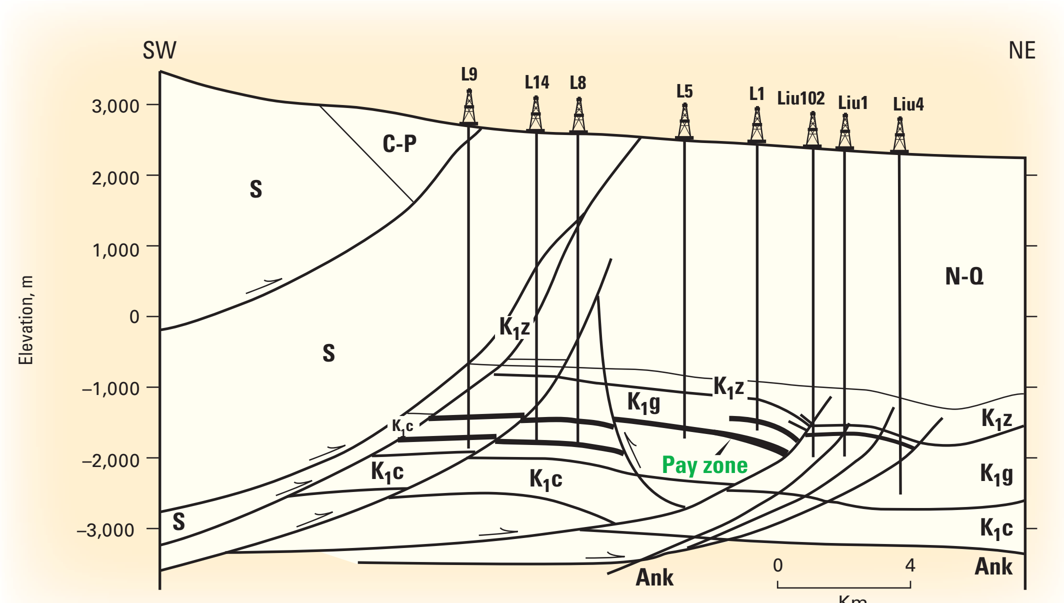
Total organic carbon is 0.6-2.0% (Table 1). Type II kerogen dominates with some types I and III kerogens. Hydrocarbon generation potential (S1 + S2) exceeds 6 mg/g. Kerogens in the Xiagou formation are mature with some submature; those in the Chijinpu formation are mature to highly mature.

Analyses of burial history, hydrocarbon generation, and evolution history indicate that hydrocarbon generation occurred principally at the end of Tertiary[18] (Figs. 8 and 9).

Reservoir rock. Reservoir rocks in the Jiuxi basin include Paleogene, Lower Cretaceous, and Middle-Lower Jurassic nonmarine clastic rocks, Lower Cretaceous lacustrine shaly dolomite, and Silurian fractured metamorphic rocks. Coarse to fine-grained sandstones of alluvial, braided stream, and deltaic origins in the Paleogene Baiyanghe formation

XIAGOU FORMATION CONFIGURATION AND OIL PAY ZONES

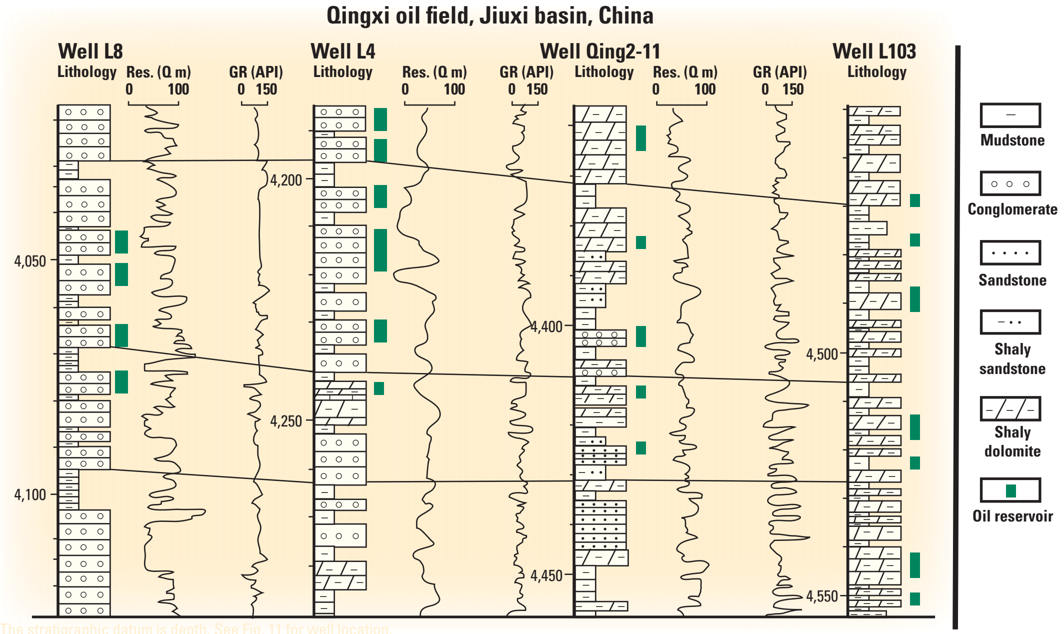
Fig. 12



See Fig. 5 for section and well location and Fig. 3 for symbol explanations.

LITHOLOGIC INTERPRETATIONS AND STRATIGRAPHIC CORRELATIONS

Fig. 13



The stratigraphic datum is depth. See Fig. 11 for well location.

have a porosity of 24% and permeability of 10-1,200 md with a mean value exceeding 100 md.

The Xiagou formation contains important porous fractured reservoir rocks (Fig. 5). In the piedmont area, the reservoir rocks are mainly alluvial-fan conglomerate, 100 to 400 m thick, and have a porosity of 6-19% (averaged at 8%) and a permeability of 0.987-44.4 md.

The lacustrine depocenter contains dolomite, shaly dolomite, and dolomitic shale, which are widely distributed and laminated. Their reservoir quality is poor, with a porosity of 1.27-7.13% (averaged at 4.31%) and a permeability of 0.1-1.6 md.[19] They are, however, extensively fractured near faults, forming porous fractured reservoirs (Fig. 10). Silurian metamorphic reservoir rocks are also fractured.

Cap rock. Illite and smectite-rich mudstones of the Paleogene Baiyanghe formation are the regional cap rocks with good seal capacity in the Jiuxi basin. Their illite content is 40-60% and smectite 30-40%.[20]

The cap rocks cover the entire basin but thin from 140 m in the Qingxi Depression to 20 m at the basin margin. The cap rocks that overlie the Cretaceous oil pools are mud rocks at the top of the Xiagou formation and in the lower part of Zhonggou formation. The thickness is 50-150 m, with a maximum thickness of 400 m in depocenter in the mountain front.

Migration and accumulation. Oil to source rock correlations[8] suggest that the oil is mainly from the Lower Cretaceous source rocks.

Oil generated in the Cretaceous source rocks in the lacustrine depocenter first accumulated in the shaly

PETROPHYSICAL CHARACTERISTICS OF RESERVOIR ROCKS OF XIAGOU FORMATION, QINGXI OIL FIELD Table 2

	Porosity, %		Permeability, md	
Lithology	Number of samples	Average	Number of samples	Average
Shaly dolomite	131	4.1	97	2.7
Dolomitic shale	106	4.7	71	4.3
Conglomerate	251	4.5	22	1.8
Sandstone	25	4.7	26	4.4

dolomite close to the kitchen and then neighboring fan-delta conglomerates at the basin margin, which formed lithostratigraphic traps. Thereafter, oil migrated along faults and-or unconformities and accumulated in structural traps and buried-hill traps. As a result, each structural belt has its own specific reservoir type.

Resources and reserves. Oil resources are estimated as 0.533 billion tons in the Jiuxi basin, among which accumulations in Cretaceous rocks account for 70%, Tertiary for 23%, and Silurian for 7%.

The total proved reserves in six oil fields are 148 million tons, among which Tertiary reserves account for 67.4%, Cretaceous for 23.1%, and Silurian for 9.5%.

Remaining resources are 0.396 billion tons, among which the Cretaceous resources account for 80%, Tertiary for 13%, and Silurian for 7%. This estimate suggests that the Cretaceous rocks have excellent prospecting potential.

Structural definition and trap configuration. The Kulongshan anticline under the Paleozoic nappes in the Qilian Mountain front is large and elongate with a gentle and broad eastern limb and a steep and narrow western limb in the map view.

The Kulongshan anticline covers 132 sq km with 1,800 m of closure. The anticline is covered by the overthrust for 6-8 km with a structural area of 97.8 sq km (Figs. 2 and 11).

The Kulongshan structure is composed of NW-trending thrusts and nearly NS-trending tear faults. The north flank is relatively steep where faults developed, while the southern flank is relatively gentle, where the Cretaceous and Tertiary strata were overthrust by Paleozoic (Silurian to Permian) metamorphic rocks.

In the piedmont nappe, hydrocarbon shows occur in the Silurian to Cretaceous interval in both hanging wall and foot wall. But the key target beds are in the Cretaceous Xiagou formation in the foot wall. The reservoirs are controlled by both lithology and fractures.

Reservoir architecture and properties. Oil accumulation in the Xiagou formation is primarily controlled by structure and lithofacies in Qingxi field. For instance, the dimensions of Kulongshan reservoirs are confined by structures (Figs. 11 and 12), with the same depth of oil-water contacts at –2,200 m elevation. The reservoir rocks are sandstones and conglomerates of fan-delta front facies (Fig. 13).

In the Liugouzhuang region, the oil-water contact is at –2,000 m elevation; and the reservoir rocks are lacustrine shaly dolomite and fractured dolomitic shale, which have a low matrix porosity but relatively high permeability and high oil production (Table 2) due to extensive fracturing.

Next: Jiuxi basin exploration history, use of modern technology, and lessons learned and their broad exploration implication. ✦

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Myanmar

Thailand's PTT Exploration & Production PLC gauged a combined gas flow of 53.83 MMcfd at the latest appraisal well drilled in Block M9 in the Gulf of Martaban off Myanmar.

Kakonna-2 was drilled to a TD of 2,607 m and encountered eight zones of gas bearing formation a total of 47 m thick. Tubing stem tests were conducted on two zones, indicating maximum flow rates of 25.7 MMcfd and 28.1 MMcfd, respectively.

The well follows a successful drilling campaign earlier this year (OGJ Online, May 23, 2007). PTTEP will drill two appraisal wells in the block, Zawtika-5 and 6, in July.

Mississippi

Odyssey Petroleum Corp., Vancouver, BC, plans to drill two 11,500-ft wells this year in Pelahatchie field, Rankin County.

One well is to be drilled in 18-5n-5e, to tap 200 ft of known oil and gas bearing formations behind pipe in the Harold Karges well in the same section. The other well is to be an infill well in 7-5n-5e, where Odyssey said geological and engineering studies indicate that more than 100 ft of oil and gas pay will be encountered.

Cretaceous Hosston is the deepest of the formations expected at the two wells. The company plans to propose a name change at its annual meeting Aug. 20 and may seek registration in the US.

Alberta bitumen development continues its rapid expansion

Guntis Moritis
Production Editor

The number of projects planned for developing the vast bitumen resources in Alberta's oil sands continues to grow. Recent reports list 30 in situ projects and 23 mining and upgrader projects in various stages of completion (Tables 1 and 2).[1-3]

The projects are in Alberta's Athabasca, Cold Lake, and Peace River regions (Fig. 1). The Athabasca region has both mining and various in situ projects, whereas the Cold Lake and Peace River, with their deeper bitumen accumulations, have only in situ projects.

Until now, most oil sands investment has focused on surface mining projects, but much of the future investment is geared toward in situ extraction and bitumen upgrading. In addition, companies will have to make investments in pipeline infrastructure to move products to markets.

From 2007 until 2016, the Alberta Energy and Utility Board (EUB) expects investment expenditure related to oil sands (surface mining, upgrading, in situ, and support services) to be $118 billion.[2]

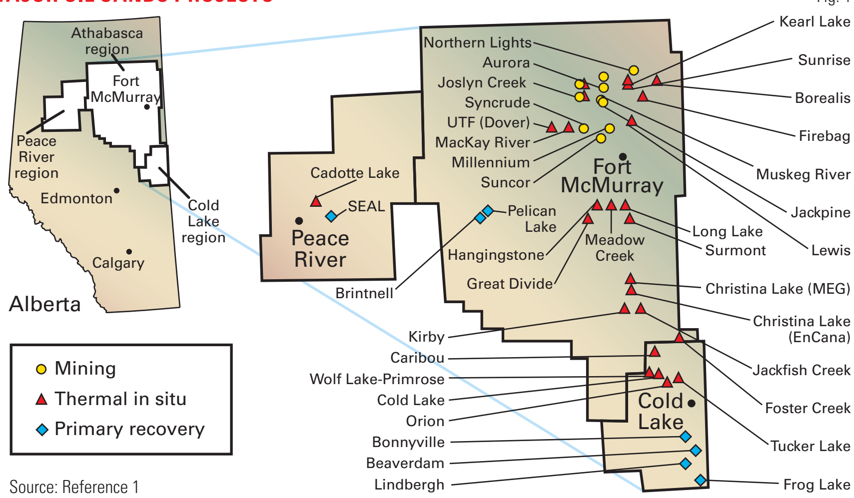
Leasing mineral rights

A report by McWilliams in a presentation said Alberta owns the mineral rights to about 81% of the province's 163 million acres.[4] The remaining 19% are federal government, aboriginal, or freehold lands. The province holds 97% of the oil sands mineral rights.

In 2006, McWilliams noted that Alberta sold 856 parcels, about 3.8 million acres, in the Athabasca, Cold Lake, and Peace River areas through public offerings. The average price was $443 (Can.)/acre. As a comparison, in 2004, 336 parcels, about 700,000 acres, were sold at an

MAJOR OIL SANDS PROJECTS

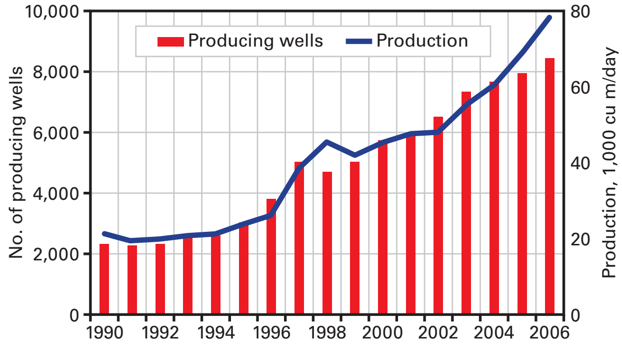
Fig. 1



Source: Reference 1

IN SITU PRODUCTION

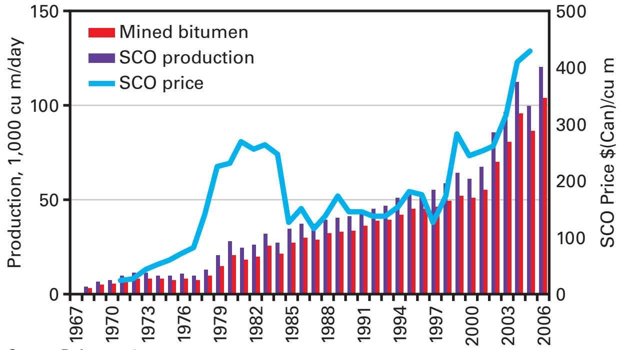
Fig. 2



Source: Reference 2

MINED PRODUCTION

Fig. 3



Source: Reference 2

average price of $97.11 (Can.)/acre.

Alberta holds public offerings of mineral rights every 2 weeks and issues leases or permits through a competitive and confidential bidding system. The highest bid wins the right to drill for and recover the minerals.

Leases typically have a primary 15-year term and can be extended, depending on the exploration work and if the lease is on production.

Resources

EUB's latest annual reserves report shows the following assessment of bitumen resources in Alberta at yearend 2006:[2]

- Initial in place: 1,701 billion bbl.
- Initial established: 179 billion bbl.
- Cumulative production: 5.4 billion bbl.
- Remaining established: 173 billion bbl.
- 2006 production: 0.458 billion bbl (1.25 million b/d).
- Ultimate potential: 315 billion bbl.

Crude bitumen is a viscous mixture of hydrocarbons that does not flow into a well naturally. The bitumen occurs in both sand (clastic) and carbonate formations, which are referred to as the oil sands. EUB's report also includes as bitumen some heavy oil resources lying in these same areas that can be produced by primary means.

The report says that the oil sands area contains 15 deposits, occupying a 54,000 sq mile area (Table 3). The main deposits are the Athabasca Wabiskaw-McMurray, Cold Lake Clearwater, and Peace River Bluesky-Gething.

EUB updated the resources in the Athabasca Wabiskaw-McMurray in 2005 and slightly revised them in 2006. It updated the Cold Lake Clearwater and Cold Lake Wabiskaw-McMurray deposit also in 2006.

In its latest report, EUB updated the Peace River Bluesky-Gething and found them to be more areally extensive than previously published.

The report says that these four deposits contain more than 60% of the total initial in-place bitumen resource and about 86% of the in-place resource found in clastics.

Of the 173 billion bbl remaining established reserves, EUB considers 82% or 141.7 billion bbl recoverable with in situ methods and the remaining 31.5 billion bbl recoverable with surface mining.

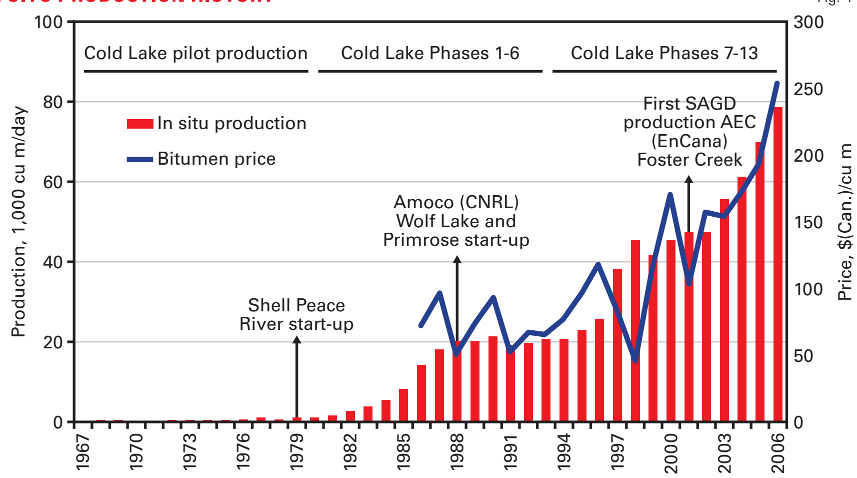
The currently active mining and in situ areas contain about 21 billion bbl out of the 173 billion bbl deemed recoverable.

EUB's report explains that bitumen saturation varies within a reservoir, decreasing as the reservoir shale or clay content increases or as the porosity decreases. Increased water saturation also decreases the amount of bitumen in the pore space.

The resource evaluation expresses bitumen saturation as mass per cent in sands and per cent pore volume in carbonates. In Cretaceous sands, the assessment used a minimum bitumen

IN SITU PRODUCTION HISTORY

Fig. 4



Source: Reference 2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MINING, UPGRADING PROJECTS

Table 1

Company	Project	Status	Start-up date	Capcity, b/d
Athabasca Oil Sands Project				
	Muskeg River mine	Operating	2002	155,000
	Expansion and debottlenecking	Application	2010	115,000
	Jackpine mine			
	Phase 1A	Approved	2010	100,000
	Phase 1B	Approved	2012	100,000
	Phase 2	Disclosed	2014	100,000
	Scotford upgrader			
	Phase 1	Operating	2003	155,000
	Debottlenecking	Application	2007	45,000
	Expansion	Application	2009	90,000
BA Energy				
	Heartland upgrader			
	Phase 1	Application	2008	54,400
	Phase 2	Application	2010	54,400
	Phase 3	Application	2012	54,400
BA Energy North West Upgrading				
	North West upgrader			
	Phase 1	Announced	2010	50,000
	Phase 2	Announced	2013	54,400
	Phase 3	Announced	2016	54,000
CNRL				
	Horizon mine and upgrader			
	Phase 1	Construction	2008	135,000
	Phase 2	Approved	2011	45,000
	Phase 3	Approved	2011	90,000
	Phase 4	Announced	2015	145,000
	Phase 5	Announced	2017	162,000
	Primrose upgrader			
	Phase 1	Announced	2,012	145,000
	Phase 2	Announced	2,015	58,000
Fort MacKay First Nation				
	Fort MacKay First Nation mine			
	Phase 1	Announced	TBD	TBD
Husky				
	Lloydminster upgrader			
	Existing operation	Operating	1992	71,000
	Debottlenecking	Operating	2006	12,000
	Expansion	Announced	TBD	67,000
Imperial/ExxonMobil				
	Kearl mine			
	Phase 1	Application	2010	100,000
	Phase 2	Application	2012	100,000
	Phase 3	Application	2018	100,000
OPTI/Nexen				
	Long Lake upgrader			
	Phase 1	Construction	2007	72,000
	Phase 2 (south)	Approved	2011	72,000
	Phase 3	Announced	2013	72,000
	Phase 4	Announced	2015	72,000
Peace River Oil Upgrading				
	Bluesky upgrader			
	Phase 1	Announced	2010	25,000
	Phase 2	Announced	TBD	25,000
	Phase 3	Announced	TBD	25,000
	Phase 4	Announced	TBD	25,000
Petro-Canada/UTS/Teck Cominco				
	Fort Hills mine			
	Phase 1 and 2	Approved	2011	100,000
	Phase 3 and 4	Approved	2014	90,000
	Fort Hills upgrader			
	Phase 1 and 2	Announced	2011	100,000
	Phase 3 and 4	Announced	2014	90,000
Suncor				
	Steepbank and Millenium mines			
	Steepbank and North Steepbank extension	Operating	1967	276,000
	Steepbank debottlenecking	Operating	2006	25,000
	Millenium debottlenecking	Construction	2008	23,000
	Tar Island upgrader			
	Base Units 1 and 2	Operating	1967	281,000
	Millenium vacuum unit	Operating	2005	43,000
	Millenium coker unit	Construction	2008	23,000
	Voyageur upgrader			
	Phase 1	Application	2010	156,000
	Phase 2	Application	2012	78,000
Syncrude				
	Mildred Lake and Aurora mining and upgrading			
	Existing facilities	Operating	1978	290,700
	Stage 3 expansion	Construction	2006	116,300
	Stage 3 debottlenecking	Announced	2011	46,500
	Stage 4 expansion	Announced	2015	139,500
Synenco				
	Northern Lights mine			
	Phase 1	Disclosure	2009	50,000
	Phase 2	Disclosure	2011	50,000
	Northern Lights upgrader			
	Phase 1	Disclosure	2009	50,000
	Phase 2	Disclosure	2011	50,000
Total (formerly Deer Creek)				
	Joslyn mine			
	Phase 1 (north)	Application	2010	50,000
	Phase 2 (north)	Application	2013	50,000
	Phase 3 (south)	Announced	2016	50,000
	Phase 4 (south)	Announced	2019	50,000
	Joslyn-Surmont upgrader			
	Phase 1	Announced	2010	50,000
	Phase 2	Announced	2013	50,000
Value Creation				
	North Joslyn upgrader			
	Phase 1	Announced	TBD	40,000

Note: TBD—to be determined.
Source: References 1-3

saturation cutoff of 3% mass and a minimum 1.5-m saturated zone thickness for in situ areas.

As of yearend 1999, EUB increased cutoffs to 6% mass and 3.0-m for areas amenable to surface mining.

In the carbonate deposits, the assessment used a cutoff of 30% bitumen saturation and a minimum 5% porosity.

EUB notes that the oil sands quality cutoff of 6% mass is more reasonable and plans to use that value in future resource updates. It adds that a change to 6% from 3% would reduce the bitumen in place as follows:

- Athabasca Wabiskaw-McMurray—20%.
- Cold Lake Clearwater—35%.
- Peace River Bluesky-Gething—50%.

EUB, however, also notes that new drilling may offset these reductions. For instance, in the Peace River Bluesky-Gething deposit, its update showed a slight increase of in-place resources due to drilling that extended the deposit especially to the northeast.

The report assumed a cutoff depth of 250 ft to separate mined and in situ resources, although it noted that some resources above a 250-ft depth might be produced with in situ methods. It identified potential mined areas using economic strip ratio (ESR) criteria, a minimum bitumen saturation cutoff of 7% mass, and a minimum 3.0-m saturated zone thickness cutoff.

The evaluation applied a combined 82% mining-extraction recovery factor to the resource volume, which reflects the combined loss, on average 18% of the in-place volume by the mining operations and the extraction facilities.

For in situ areas amenable for thermal, EUB used a minimum 10.0-m zone thickness in all deposits except the Athabasca Wabiskaw-McMurray, in which it used a 15.0-m cutoff in the Wabiskaw zones.

In primary development, EUB used a minimum 3.0-m zone thickness or lower if current production is from a zone with less thickness.

For in situ areas, EUB used a mini-

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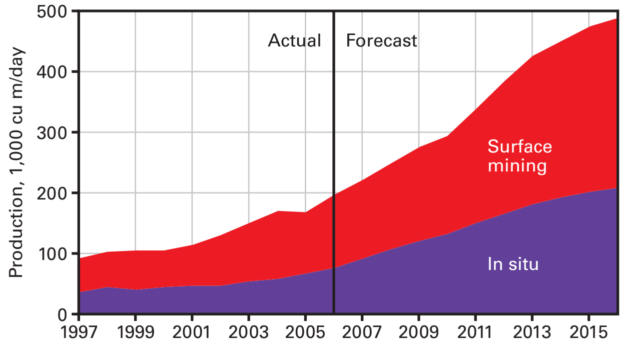
Production forecast

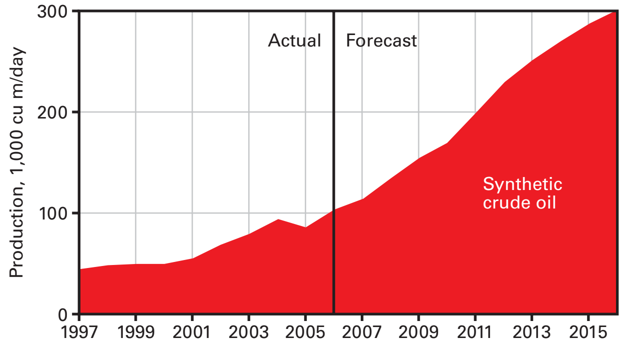
Fig. 5



Source: Reference 2

SCO forecast

Fig. 6



Source: Reference 2

mum saturation cutoff of 3% mass for all deposits but expects to increase that in future reports. The evaluation applied a 20% recovery factor for thermal projects and a 5% recovery factor for primary projects.

EUB noted that the deposit-wide recovery factor for thermal development is less than in some of the active projects so as to account for uncertainties. It also is currently reviewing these overall recovery factors.

For thermal commercial projects in the Peace River, Athabasca, and Cold Lake areas, the evaluation used 40, 50, and 25% recovery factors, respectively to reflect various steaming strategies and project designs.

Production

The EUB report noted that bitumen production from in situ projects increased by 13% in 2006 compared with 2005, while production from mining projects increased by 21%. Overall raw bitumen production increased by about 18%.

In 2006, the minable area produced 278 million bbl, while in situ projects produced 180 million bbl.

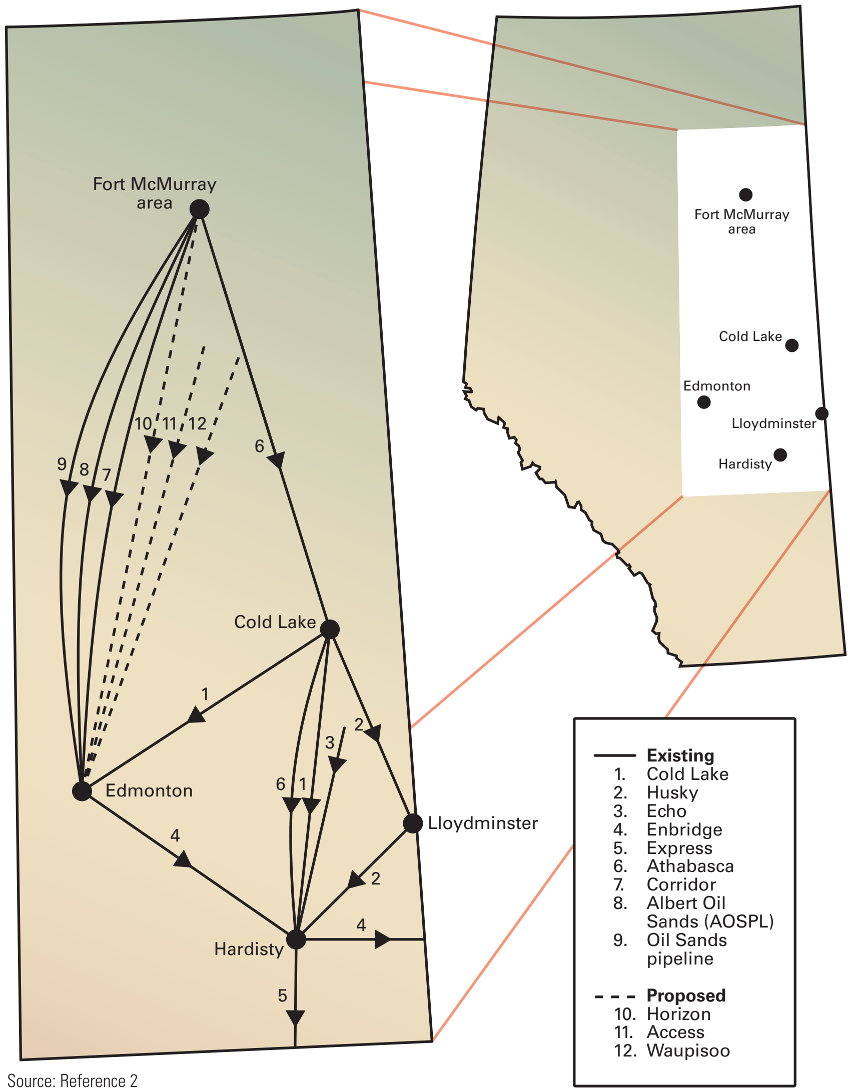
In situ recovery includes both primary methods and enhanced recovery, such as injection of steam, water, or other solvents into the reservoir to mobilize the bitumen.

Production in 2006 from the three current surface mining projects was:

1. Syncrude Canada Ltd.—310,000 b/d.
2. Suncor Energy Inc.—303,000 b/d.
3. Albian Sands Energy Inc.—146,000 b/d.

Alberta bitumen pipelines

Fig. 7



Source: Reference 2

IN SITU PROJECTS— (CONTINUED ON P. 50)

Table 2

Company	Project	Status	Start-up date	Capacity, b/d
Black Rock				
	Orion (Hilda Lake)			
	Pilot	Operating	1997	500
	Phase 1	Approved	2007	10,000
	Phase 2	Approved	2009	10,000
CNRL				
	Birch Mountain			
	Phase 1	Announced	2013	30,000
	Phase 2	Announced	2015	30,000
	Gregoire Lake			
	Phase 1	Announced	2016	30,000
	Phase 2	Announced	2018	30,000
	Phase 3	Announced	2020	30,000
	Phase 4	Announced	2023	30,000
	Kirby			
	Phase 1	Announced	2011	30,000
	Primrose			
	South	Operating	1985	50,000
	North	Operating	2006	30,000
	East	Construction	2009	30,000
Connacher				
	Great Divide			
	Phase 1	Application	2008	10,000
ConocoPhillips				
	Surmont			
	Phase 1	Construction	2007	25,000
	Phase 2	Approved	2008	25,000
	Phase 3	Approved	2011	25,000
	Phase 4	Approved	2014	25,000
Devon				
	Jackfish			
	Phase 1	Construction	2008	35,000
	Phase 2	Disclosure	2010	35,000
EnCana				
	Borealis			
	Phase 1	Announced	2010	20,000
	Phase 2	Announced	2011	20,000
	Phase 3	Announced	2012	20,000
	Phase 4	Announced	2013	20,000
	Phase 5	Announced	2014	20,000
	Christina Lake			
	Phase 1A	Operating	2002	10,000
	Phase 1B	Approved	2008	30,000
	Phase 1C	Approved	2009	30,000
	Phase 1D	Announced	2010	30,000
	Expansion 1	Announced	2011	30,000
	Expansion 2	Announced	2012	30,000
	Expansion 3	Announced	2013	30,000
	Expansion 4	Announced	2014	30,000
	Expansion 5	Announced	2015	30,000
	Foster Creek			
	Phase 1A	Operating	2001	24,000
	Phase 1B debottlenecking	Operating	2003	6,000
	Phase 1C Stage 1	Operating	2005	10,000
	Phase 1C Stage 2	Operating	2006	20,000
	Phase 1D	Operating	2006	20,000
	Phase 1E	Operating	2007	20,000
	Expansion 1	Announced	2009	25,000
	Expansion 2	Announced	2011	25,000
Husky				
	Sunrise			
	Phase 1	Approved	2008	50,000
	Phase 2	Approved	2010	50,000
	Phase 3	Approved	2012	50,000
	Phase 4	Approved	2014	50,000
	Tucker Lake			
	Phase 1	Operating	2006	30,000
Imperial Oil				
	Cold Lake			
	Phases 1-10: Leming, Maskwa, Mahikan	Operating	1985	110,000

At yearend 2006, the EUB report says about two-thirds of the initial minable established reserves were under active development. The developments that EUB considers active are the three projects on production and Fort Hills, Horizon, and Jackpine. The report does not consider the recently approved Kearl mine in the active projects.

Companies have drilled most of the in situ producing wells in the oil sands as deviated wells from pads to minimize the drilling and production footprint. EUB's report says that from 1985 through yearend 2006, companies had drilled 29,558 wells to explore for and develop oil sands (Table 4). About 8,500 wells were producing during 2006, with the average well producing 61 bo/d (Fig. 2).

EUB noted that upgrading the mined bitumen yielded 240 million bbl of synthetic crude oil (SCO), while companies mainly marketed production from most in situ projects as nonupgraded crude bitumen.

Fig. 3 shows the history of mined bitumen production in Alberta, starting with production from the Great Canadian Oil Sands (Suncor) project in 1967. Also shown is the price of SCO from 1971, which the EUB report says is generally at a premium to light crude oil.

Fig. 4 shows the historical production and price of in situ bitumen produced in Alberta. Imperial Oil Ltd.'s Cold Lake cyclic-steam-stimulation recovery project has accounted for most of the in situ production. EUB says Cold Lake's price generally follows the light crude oil price but at a discount of between 50 and 60%.

The EUB estimates that bitumen production will more than double by 2016 to about 3 million b/d (Fig. 5).

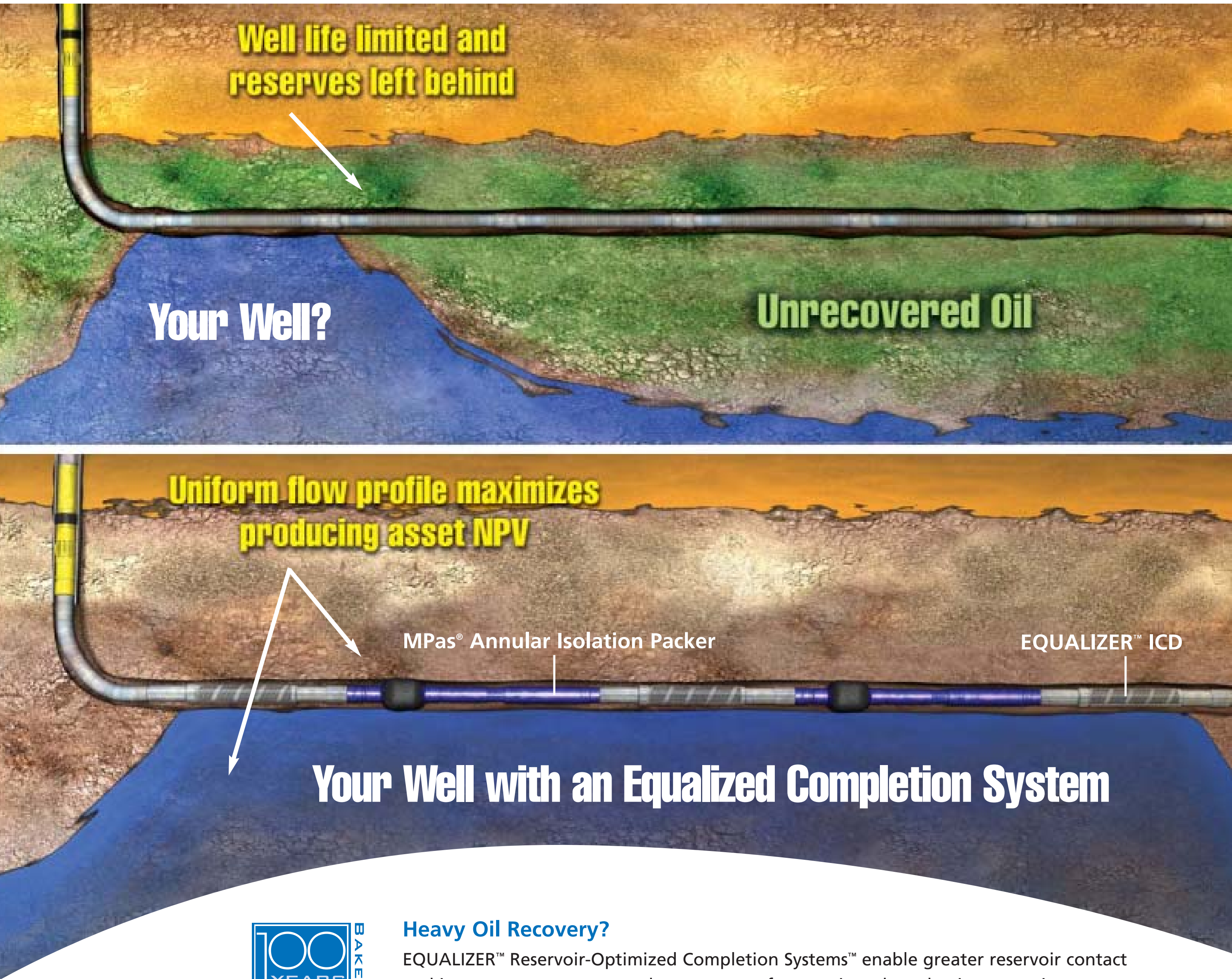
EUB assumed that West Texas Intermediate (WTI) crude oil would average $62/bbl in 2007 and rise to $69/bbl by 2016.

EUB expects upgraded bitumen product to increase more than threefold, from 661,000 b/d in 2006 to 1.898 million b/d by 2016.

If production follows the forecast, Alberta will required additional crude oil pipeline capacity by 2010-2012.

EUB also expects exports of SCO products will increase from 63% of the total SCO production in 2006 to 83% of SCO production by 2016.

Less water, more oil. . .even if it's heavy



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IN SITU PROJECTS—(CONTINUED FROM P. 48)

Table 2

Company	Project	Status	Start-up date	Capacity, b/d
Imperial Oil	Cold Lake (continued)			
	Phases 11-13: Mahkeses	Operating	2003	30,000
	Phases 14-16: Nabiye, Mahikan, North	Construction	2006	30,000
JACOS				
	Hangingstone			
	Pilot	Operating	2002	10,000
	Phase 1	Disclosed	2010	25,000
	Phase 2	Disclosed	2012	25,000
MEG				
	Christina Lake			
	Pilot	Construction	2007	3,000
	Commercial	Application	2008	22,000
North American (Statoil)				
	Kai Kos Dehseh			
	Phase 1 (Leismen)	Announced	2008	10,000
	Phase 2	Announced	2010	30,000
	Phase 3	Announced	2011	40,000
	Phase 4	Announced	2013	40,000
	Phase 5	Announced	2015	40,000
OPTI/Nexen				
	Long Lake			
	Pilot	Operating	2003	2,500
	Phase 1	Construction	2007	72,000
	Phase 2 (south)	Approved	2010	72,000
	Phase 3	Announced	2012	72,000
	Phase 4	Announced	2014	72,000
Orion				
	Whitesand			
	Pilot	Start-up	2006	2,000
Petro-Canada				
	Card			
	Phase 1	Announced	TBD	40,000
	Dover			
	SAGD pilot	Operating	2001	1,400
	VAPEX pilot	Operating	2003	100
	Lewis			
	Phase 1	Disclosure	TBD	40,000
	Phase 2	Disclosure	TBD	40,000
	MacKay River			
	Phase 1	Operating	2002	33,000
	Phase 2	Announced	2009	40,000
	Meadow Creek			
	Phase 1	Approved	TBD	40,000
	Phase 2	Approved	TBD	
Shell				
	Cadotte Lake			
	Pilot	Operating	1979	1,000
	Phase 1	Operating	1986	11,000
	Carmon Creek			
	Phase 1	Disclosure	2009	18,000
	Phase 1 expansion	Announced	2012	35,000
	Phase 2	Announced	2012	35,000
Suncor				
	Firebag			
	Phase 1	Operating	2004	33,000
	Phase 2	Operating	2006	33,000
	Cogeneration and expansion	Construction	2009	25,000
	Phase 3	Approved	2008	35,000
	Phase 4	Approved	2009	35,000
	Phase 5	Announced	2012	50,000
	Phase 6	Announced	2013	50,000
	Phase 7	Announced	2014	50,000
	Phase 8	Announced	2015	63,000
Total (formerly Deer Creek)				
	Joslyn			
	Phase 1	Operating	2004	2,000
	Phase 2	Construction	2006	10,000
	Phase 3A	Disclosed	2009	15,000
	Phase 3B	Disclosed	2011	15,000
Value Creation				
	Halfway Creek			
	Phase 1	Announced	2009	10,000
	North Joslyn			
	Phase 1	Announced	TBD	40,000

Note: TBD—to be determined.
Source: References 1-3

Upgrading, transportation

Upgrading converts bitumen and heavy crude oil into SCO by adding hydrogen, subtracting carbon, or doing both. The process also may remove sulfur in either its elemental form or as a part of the oil sands coke.

EUB's report says companies stockpile most oil sands coke, with some small amounts being burned to generate electricity. Companies also either stockpile elemental sulfur or ship it to facilities that convert it to sulfuric acid, which mainly is used in fertilizer manufacturing.

Pipeline transport of bitumen crude requires addition of a diluent such as a lighter viscosity product, which in Alberta is mainly pentanes plus. Pentanes plus represent about 30% of the blend volumes. These diluents are recycled if the blend has an Alberta destination but usually not returned to the province from markets outside Alberta, according to EUB's report.

Companies can use SCO as a diluent, although this requires a volume of about 50% SCO in the blend. Other used diluents are naphtha and light crude oil.

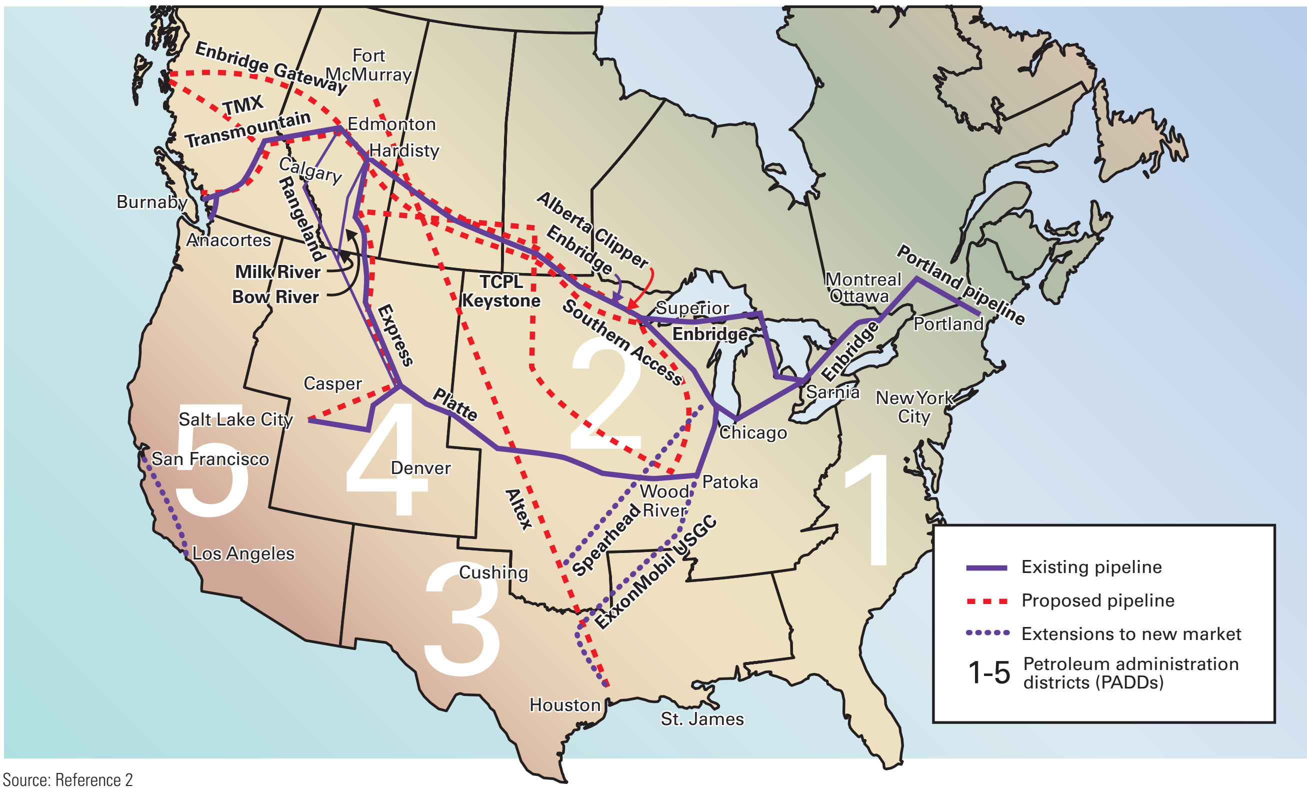
Heated and insulated pipelines decrease the amount of diluent required diluent.

EUB's forecast of upgrading considered potential production from existing facilities and supply from future projects, as follows:

- Suncor's existing production and expected expansions, including Voyageur and Voyageur South.
- Syncrude's existing production and expected expansions, including Stage 3 with start-up in 2006 and the Stage 3 debottleneck of the four-stage project that began in 1996.
- Albian Sands' existing project and debottlenecking projects and expansion, approved by EUB in November 2006 and scheduled for completion by yearend 2010.
- CNRL's Horizon project, approved by the EUB in January 2004 and with proposed production starting in 2008.
- Shell Canada's Jackpine mine, ap-

CANADIAN, US PIPELINES

Fig. 8



Source: Reference 2

proved by EUB in February 2004 and with production expected 2 years after the Muskeg Mine expansion in late 2010.

• Petro-Canada-UTS Energy-Teck Cominco's Fort Hills project (originally TrueNorth Energy's Fort Hills Oil Sands project), approved by the EUB in October 2002 with production proposed by 2011.

• Imperial Oil-ExxonMobil's proposed multistage Kearl mine project, approved by EUB in February 2007 with start-up expected by late 2010. Current plans do not include on site upgrading facilities.

• Deer Creek's (Total E&P Canada) proposed multistage Joslyn North mine project with production expected in 2013.

• Synenco Energy-SinoCanada

INITIAL IN-PLACE BITUMEN ESTIMATE

Table 3

Oil sands deposit	Initial in place, billion bbl	Area, 1,000 acres	Average pay thickness, ft	Average bitumen saturation — Mass, %	Average bitumen saturation — Pore volume, %	Average porosity, %
Athabasca						
Grand Rapids	54.6	1,703	24	6.3	56	30
Wabiskaw-McMurray (mineable)	101.2	633	100	9.7	69	30
Wabiskaw-McMurray (in situ)	831.2	11,527	43	10.2	73	29
Nisku	65.0	1,233	26	5.7	63	21
Grosmont	317.7	10,297	34	4.7	68	16
Subtotal	**1,369.6**					
Cold Lake						
Grand Rapids	108.9	4,223	19	9.5	66	31
Clearwater	59.3	1,070	39	8.9	59	31
Wabiskaw-McMurray	27.0	1,198	18	7.3	59	27
Subtotal	**195.1**					
Peace River						
Bluesky-Gething	69.0	2,511	20	8.1	68	26
Belloy Debolt	1.8	64	26	7.8	64	27
	49.1	746	78	5.1	65	18
Shunda	15.8	353	46	5.3	52	23
Subtotal	**135.6**					
Total	**1,700.3**					

Source: Reference 2

Petroleum's Northern Lights mining and extraction project, proposed as a two-stage project with initial start-up in late 2010.

EUB's report says that during 2006 only 9% of the in situ bitumen was upgraded in Alberta, but it forecasts that this will increase to 43% by 2016 (Fig. 6).

With the expected increase in both SCO and non-upgraded bitumen over the forecast period, Alberta will require additional pipeline capacity. Fig. 7 shows the existing pipelines and proposed bitumen pipelines in Alberta, while Fig. 8 shows existing and proposed pipelines the move Alberta's crude to markets outside the province. ✦

No. of bitumen wells drilled

Table 4

	Development commercial	Development experimental	Exploration	Total
1985	975	229	593	1,797
1986	191	75	171	437
1987	377	132	105	614
1988	660	54	276	990
1989	37	24	246	307
1990	69	30	122	221
1991	91	13	51	155
1992	101	2	13	116
1993	290	6	5	301
1994	143	0	53	196
1995	828	1	222	1,051
1996	1,675	15	459	2,149
1997	2,045	8	645	2,698
1998	270	6	500	776
1999	502	0	351	853
2000	890	2	576	1,468
2001	818	4	1,115	1,937
2002	1,056	8	1,222	2,286
2003	1,000	0	1,610	2,610
2004	859	0	1,739	2,598
2005	1,158	2	1,496	2,656
2006	1,147	0	2,195	3,342
Total	**15,182**	**611**	**13,765**	**29,558**

Source: Reference 3

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Canadian, US processors adding capacity to handle additional oil sands production

David N. Nakamura
Refining/Petrochemical Editor

Refiners in the US and operators in Canada are adding capacity to handle additional volumes of bitumen and synthetic crude oils from increased oil sands production. Rising crude prices in the past few years and increased demand for refined products have pushed up oil sands production substantially (see article on p. 43).

Producers also have to decide what types of products will match up with future processing configurations in Canada and the US. They have the choice of producing bitumen, synthetic crude oil (SCO), a synthetic-bitumen blend (synbit), or a condensate-bitumen blend (dilbit).

According to a 2006 study from Canada's National Energy Board, the light-heavy crude price differential will remain wide for the next several years until sufficient upgrading capacity is added.[1] Because international heavy crude output is also rising, NEB predicts that Canadian crude will continue to be heavily discounted.

Core markets for oil sands crudes include Canada, US Petroleum Administration for Defense District (PADD) II, PADD IV, and Washington state.[1] Canadian producers are also considering expansion into markets in the US Mideast, US Gulf Coast, and even perhaps Asia.

Fig. 1 shows that production in Canadian crude will increase to 3.3 million b/d in 2015 from about 2.5 million b/d in 2006.[2]

Bitumen vs. SCO

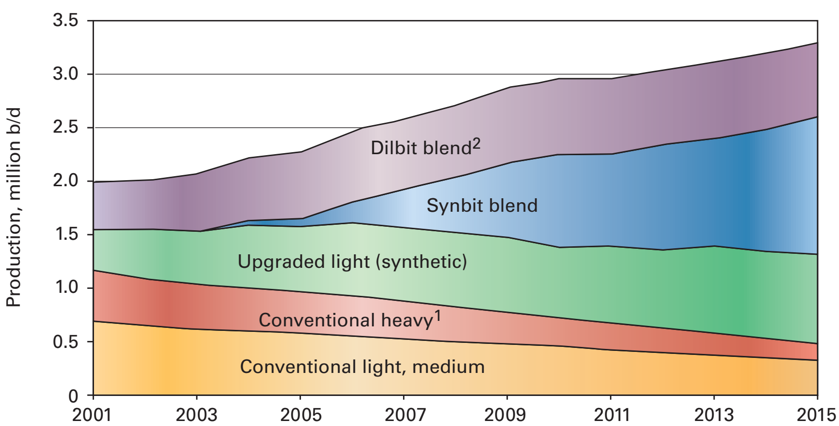
New Canadian oil sands production must either upgrade bitumen to SCO, or dilute it to synbit or dilbit, before transporting it to the end user. Incentives for producers to invest in processing include the ability to capture the light-heavy differential. SCO is more marketable and easier to transport than bitumen blends.

Bitumen requires diluent blending for pipeline transport, has a high residual content that requires more conversion (coking or hydrocracking), and is of low quality.[2] Bitumen is not a good fit with refineries designed for light, sweet crudes. It also requires large amounts of hydrogen for hydroprocessing and creates many unwanted by-products.

SCO, on the other hand, can have a much higher quality, depending on the degree of processing. Premium SCO is a bottomless, refined product. Sour synthetic is partially

CANADIAN CRUDE PRODUCTION

Fig. 1



Note: 1. Conventional heavy excludes upgrader feedstock.
Note: 2. Dilbit blend includes upgraded heavy.
Source: Canadian Association of Petroleum Producers

upgraded and may or may not have a bottoms component. And other new formulations are planned in new projects.[2]

Disadvantages of SCO in conventional refineries are the low quality of distillate produced, high amounts of aromatics, and that only a limited amount of SCO can be processed.

Light sweet SCO in particular has a low sulfur content and produces very little heavy fuel oil.[3] The latter is desirable in Alberta, where there is almost no market for heavy fuel oil.

Fig. 2 shows refinery yields that are feeding different crudes. It shows that SCO is a much higher quality crude than bitumen.

In Alberta, much of the bitumen is upgraded to SCO. Three major upgraders produced about 258,000 b/d (Suncor Energy Inc.), 261,000 b/d (Syncrude), and 141,000 b/d (Shell Canada) of SCO in 2005.[3]

Suncor's plant produces light sweet crude, medium sour crude, and diesel. The Syncrude plant produces light sweet SCO. The Shell upgrader produces intermediate refinery feedstocks and sweet and heavy SCOs.

Fig. 3 shows expected SCO production from Alberta based on project expansions and new upgraders.[3]

Demand for Alberta SCO will be from existing markets that are losing other sources of light crudes. The largest export markets for Alberta SCO and bitumen are the US Midwest and Rocky Mountain regions.

Fig. 4 shows that oil sands products have become more diverse and are targeting different refining markets.[4]

Canadian refining, upgrading

According to the NEB study, Canada's refining and upgrading industry does not hold significant growth opportunities for oil sands producers. Canada's 19 refineries have a combined crude processing capacity of just more than 2 million b/d.

In 2005, less than 50% of Ontario's crude requirements were from western Canada; only 22% was SCO and blended bitumen.[1] There are few growth opportunities for western Canadian crude in Ontario and Quebec.

Western Canadian refineries process exclusively western Canadian production. In 2005, nearly 40% of crude refined in western Canada was SCO (35%) and blended bitumen (4%).[1 3] According to the Alberta Energy and Utilities Board, the nine refineries in western Canada had a total crude capacity of about 577,000 b/d.

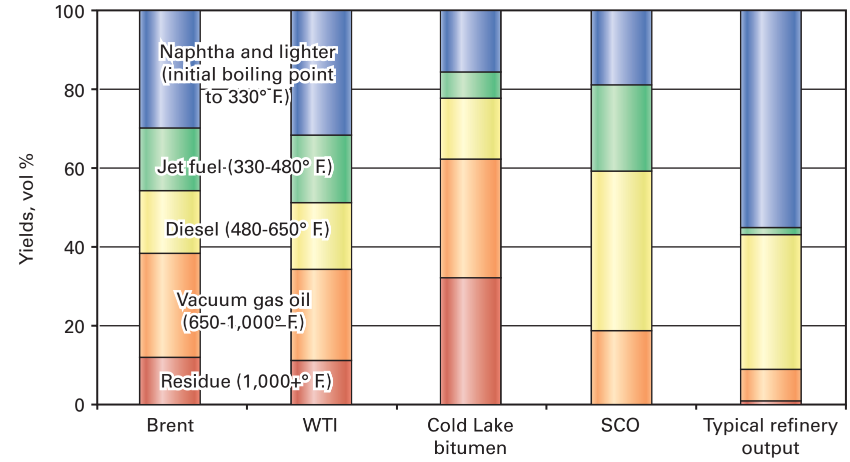
In 2006, the five refineries in Alberta fed about 206,000 b/d of SCO and about 20,000 b/d of non-upgraded bitumen.[3] The five refineries have a combined crude capacity of about 476,400 b/d.

In 2003, Petro-Canada announced that it would convert its Edmonton refinery to handle exclusively oil sands crude, according to the NEB study. By 2008, the refinery will process 135,000 b/d of oil sands crude, which will displace conventional crude currently processed. The NEB study reported that Petro-Canada would obtain these supplies through an agreement with Suncor, which will process bitumen from Petro-Canada's MacKay River in situ facility into sour SCO.

In March 2006, Husky Energy Inc.

Typical yields

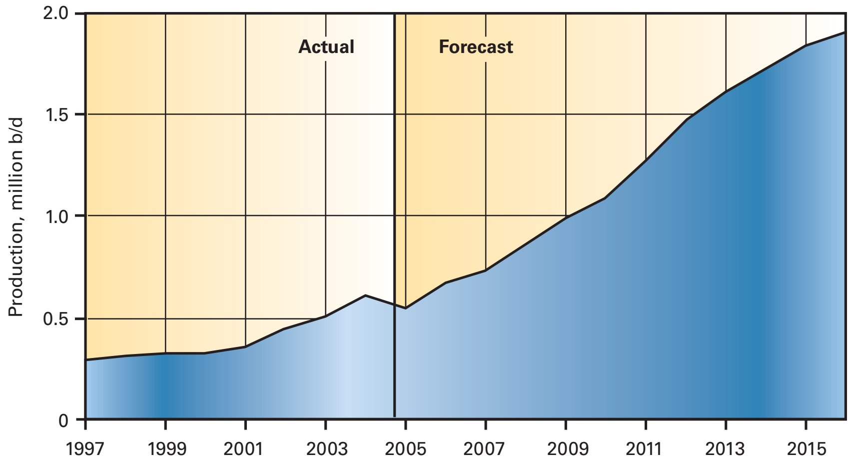
Fig. 2



Source: Reference 2

Alberta SCO production

Fig. 3



Source: Alberta Energy and Utilities Board

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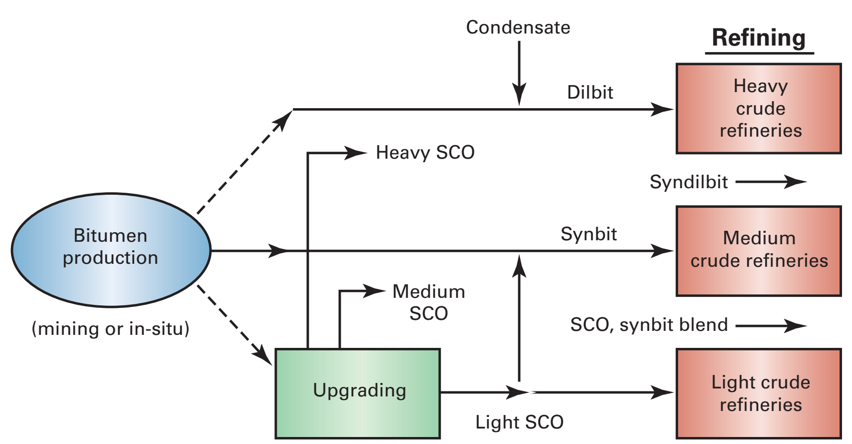
OIL SANDS PRODUCTS

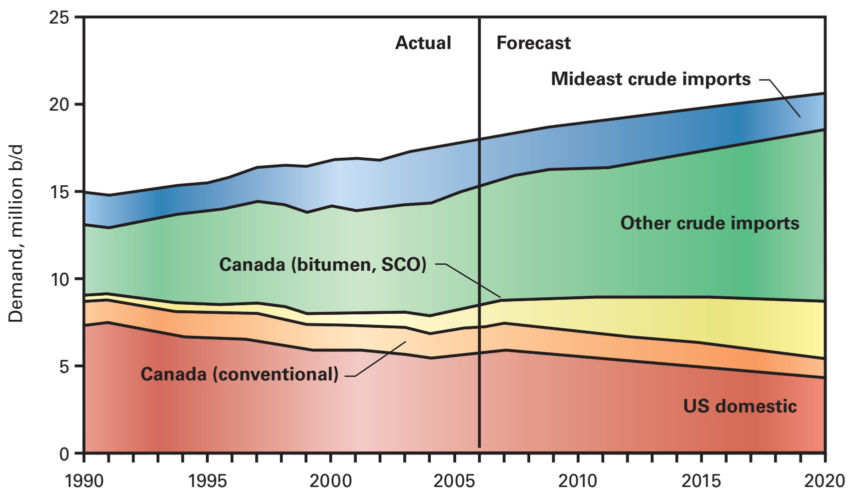
Fig. 4



Source: Reference 4

US, CANADIAN CRUDE

Fig. 5



announced that it is proceeding with detailed engineering for its project that would nearly double capacity at its upgrader at Lloydminster to 150,000 b/d by 2009 from its current 80,000 b/d. "It would enable Husky to capture full value from increased production at its Cold Lake and Athabasca oil sands projects," according to the NEB study.

Husky also announced on May 7 that it is acquiring Valero Energy Corp.'s 165,000-b/sd Lima, Ohio, refinery. The $1.9 billion sale was to close at the end of second-quarter 2007. This would allow Husky a direct outlet for its oil sands production.

There have been three merchant upgrader proposals announced, according to the NEB study.

The BA Heartland Upgrader project will take place in three phases, with the first phase starting up in early 2008. The first phase will process 77,000 b/d of bitumen blend. The project will have a total processing capacity of 250,000 b/d.

North West Upgrading Inc. is planning to construct a heavy oil upgrader near Edmonton. The first phase is to come on stream in early 2010 and will upgrade 50,000 b/d of bitumen to SCO, according to NEB. North West is planning as many as three additional phases by 2015, with a total processing capacity of 231,000 b/d and would produce 180,000 b/d of SCO and 42,000 b/d of diluent.

Peace River Oil Upgrading Inc. has proposed a 20,000-b/d bitumen processing facility near McLennan, Alta., according to NEB.

US refining

US refineries are Canada's largest market for crude exports and, according to the NEB study, "possess the greatest potential for increased penetration of oil sands derived crude oil." In 2005, Canada supplied nearly 10% of US crude feed.

Fig. 5 shows combined US and Canada crude production and that falling production in the US will be offset by more crude from Canada.

In US Petroleum Administration for Defense District I (East Coast), only the United Refining Co. refinery, Warren, Pa., processes western Canadian crude. In 2005, it processed 21% SCO and 8% blended bitumen, according to the NEB study. In September 2006, the company announced that it was delaying a project for a new coker due to "uncertainty in the petroleum markets."

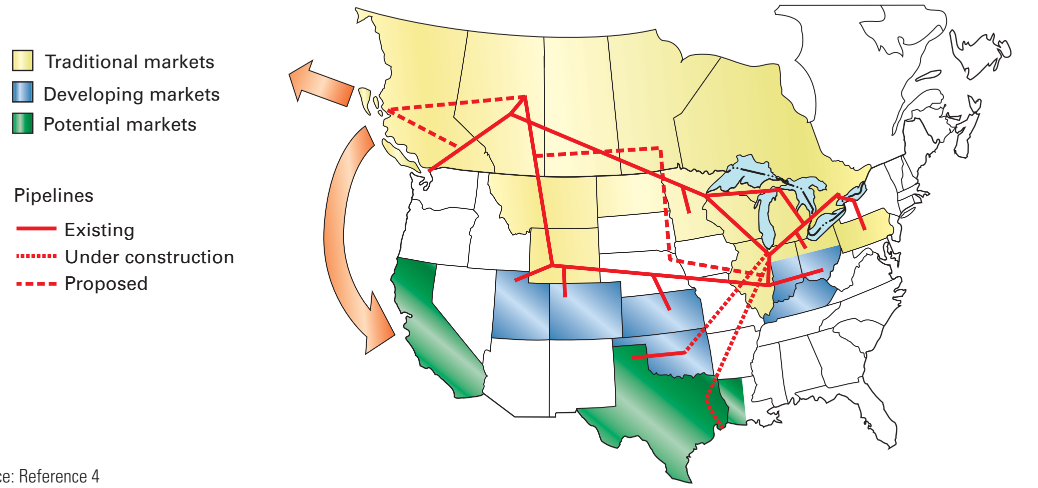
PADD II (US Midwest) is the largest market for western Canadian crude: In 2005, 70% of western Canada's crude exports were to PADD II, according to NEB. SCO comprised 20% of that volume and blended bitumen was 19%.

Because refineries in Northern PADD II are complex, they are well positioned to run more bitumen blends and SCO. Especially wide light-heavy differentials are resulting from rising output from oil sands and conventional production in Northern states.

"This could be alleviated in the future," according to NEB, "as a number of companies identified an interest in constructing a coker or developing refinery expansion plans that would allow them to process heavier crude oil to take advantage of the light-heavy differential and the expected increase in oil sands production."

WESTERN CANADIAN CRUDE MARKETS

Fig. 6



Source: Reference 4

Canadian heavy crude has the largest market share in US Midwest refineries, which processed 3.3 million b/d of crude in 2005, of which 24% was heavy sour crude.[4] Nearly all was from Canada. Canadian light crude had a smaller market share.

PADD III (US Gulf Coast) is an attractive market for Canadian producers due to the complexity of refineries there. Bitumen blends especially could compete against imports from Venezuela and Mexico.

PADD IV (US Rocky Mountain) refineries have traditionally been a significant market for western Canadian crudes. Recently, however, higher prices have resulted in more drilling and production in the district, according to NEB.

"Refiners in PADD IV are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crudes," according to the NEB study.

"The large discount is in reaction to aggressive Canadian crude pricing, shortage of refinery capacity, and the lack of pipeline capacity to move the crude oil to other markets. Due to its size and the complexity of its refineries, PADD IV will continue to be a marginal growth market for western Canadian crude oil, particularly SCO and blended bitumen," says the study.

It considers PADD V (US West Coast) a growth market for western Canadian crude, especially Washington. This is due to a decline in the availability of Alaska North Slope crude. In 2006, Washington received only 11% of its crude from Canada.

Fig. 6 shows the different markets and pipeline systems for western Canadian crude.

Market expansion

High oil prices will continue to compel oil sands expansions. The NEB study outlined a scenario in which oil sands crude would expand its markets:

1. Fill existing markets, including Washington, PADD II, PADD IV, and additional volumes in Canada.

2. Expand into southern PADD II and PADD III and refinery expansions and conversions in northern PADD II, IV, and V. Southern PADD II could take 40,000 b/d more with the expansion of the Spearhead pipeline, and the US Gulf Coast could take up to 400,000 b/d if the necessary pipeline capacity existed. NEB estimates that in the next 10 years, PADD II could take an additional 500,000 b/d.

3. Develop new markets such as California and Asia. This would require new pipelines or expansions.

Because the light-heavy differentials should continue for the near future, this price environment should provide a strong incentive for US refiners to add conversion capacity. Traditional inland markets could add up to 200,000 b/d of resid conversion capacity by 2010.[4] ✦

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Correction

The article "Study outlines European refinery demand to 2015" (OGJ, May 14, 2007, p. 46) inadvertently failed to mention that the 2015 demand scenarios were based on supply-demand forecasts from an industry study by Wood MacKenzie. In addition, Figs. 1 and 2 were from the Wood MacKenzie study.

European gas-supply security hinges on solving LNG issues

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"Energy security" has become a key word in understanding European politics. Even more than its world environmental leadership, the European Union is apparently defining itself around the need–or the perceived need–of developing a common energy policy, despite the fact that under the European Treaty energy is left to the member states.[1]

The commission, Europe's executive body, has set three goals for its energy policy:

1. Creation of an internal market.
2. Security of supply.
3. Promotion of environmental sustainability.

The idea that Europe's energy supplies are not secure enough rests upon the belief that Europe's increasing dependence on imported hydrocarbons "carries political and economic risks."[2] There are at least two reasons for this.

One is merely ideological or political: It has to do with the myth that energy, as a strategic sector, should be produced domestically, as well as with Europe's obsession with decreasing the carbon component of its economy.

There is also a more pragmatic reason: Europe depends upon a small number of providers especially for natural gas, which in turn is becoming the single most important energy source for the continent. This helps to explain why for Europe, LNG is not just another way to meet its energy needs: It is also a political challenge.

According to the commission, indeed, to promote energy security "Projects should be developed to bring gas from new regions, to set up new gas hubs in central Europe and the Baltic countries, to make better use of strategic storage possibilities, and to facilitate the construction of new liquid natural gas terminals."[3]

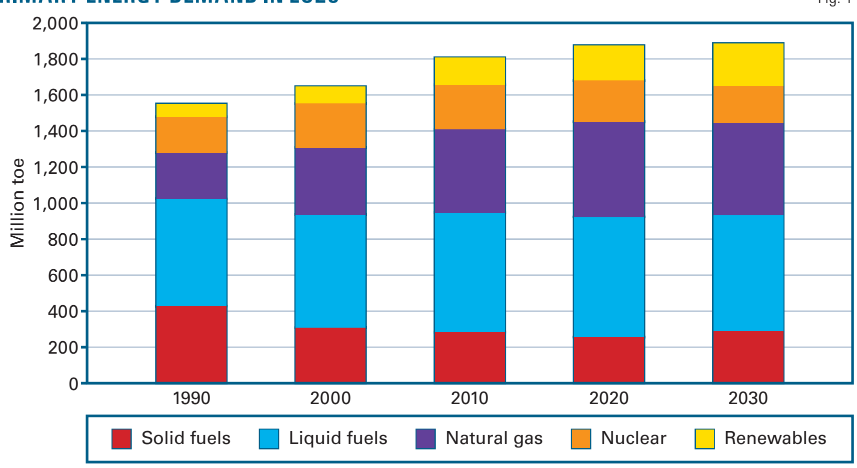
European situation

Europe is becoming increasingly dependent on natural gas because such fuel is, at the same time, economically competitive and environment friendly. Compared with other fossil fuels, its greenhouse gas emissions are significantly lower. In fact, the amount of CO_2 emissions produced per unit of electricity generated by the burning of natural gas are, respectively, 49% and 32% lower than with coal or oil.[4]

European consumption of electricity is growing as well, and electricity is increasingly generated by natural

PRIMARY ENERGY DEMAND IN EU25

Fig. 1



Source: European Commission

gas, which apparently is more socially accepted than coal and nuclear. As a result, the European energy mix is shifting from being coal and nuclear-based towards being based upon natural gas, both in absolute and relative terms, as Figs. 1 and 2 show.

What these figures don't show is that natural gas is becoming even more fundamental in the EU15, that is, in Western Europe where demand growth is slower but environmental requirements, particularly those CO_2-related, are ever more stringent.

As natural gas becomes more important, two other trends are set in motion.

On the one hand, domestic production of methane is steadily declining, while the relative weight of only two gas producers, i.e. Russia and Algeria, increases. While the quota of imported energy sources in general will increase to 65% of the total by 2030 from 50% now, the share of imported gas will grow to 84% from 54%.

Domestic energy production in the EU25 grew to 896.6 million tonnes of oil equivalent (toe) in 2000 from 877.84 in 1990, but then it started to decline to 888.17 million toe in 2003. Likewise, natural gas domestic production peaked at 196.66 million toe in 2000 then declined to 189.39 million toe in 2003. In 2004, EU15 alone relied on only three countries–Norway, Russia, and Algeria–for more than 80% of its gas imports (Table 1).

Concerns

European policy-makers find such a scenario concerning for two reasons.

One is merely political: As Europe learned at its own expense, its reliance on Russia in particular carries risks as well as benefits. While Russia's proven gas reserves are the largest in the world, Pres. Vladimir Putin is clearly aiming to consolidate his regional leadership by using gas as a political weapon. In January 2006 he turned off gas to Ukraine–a transit country for pipelines to Europe–which did not hesitate to take gas from the flow headed westwards.

Even though the practical loss of gas was limited, Europe understood then that it was at continuous risk of seeing its deliveries suspended or reduced, even though it isn't directly involved in disputes. Luckily, it is unlikely that Russia will ever turn off its gas to the EU, except for short periods of time, as happened in January 2006. After all, Russia depends upon European money as much as Europe depends upon Russian gas. And, while it is true that pipelines can't be redirected so that Europe has little ability to adjust in the short term, that is true for Russia as well: Russia won't be able to export its gas elsewhere.

A second and perhaps more serious problem is Russia's ability to keep pace with growing demand, both internal and external. Russian companies just can't afford the investments needed to develop existing and new fields, let alone technologies and know-how, and international oil companies find a hostile and risky environment in Moscow. According to some experts, then, the risk that around 2010 Russia will be unable to meet its supply commitments is real.

The risk has nothing to do with physical scarcity of gas; it is caused by the lack of a stable and investment-friendly legal framework in Russia, so that international oil companies hesitate or are discouraged, while national companies, including but not limited to state-owned Gazprom and Rosneft, are unable to achieve production increases that are needed.

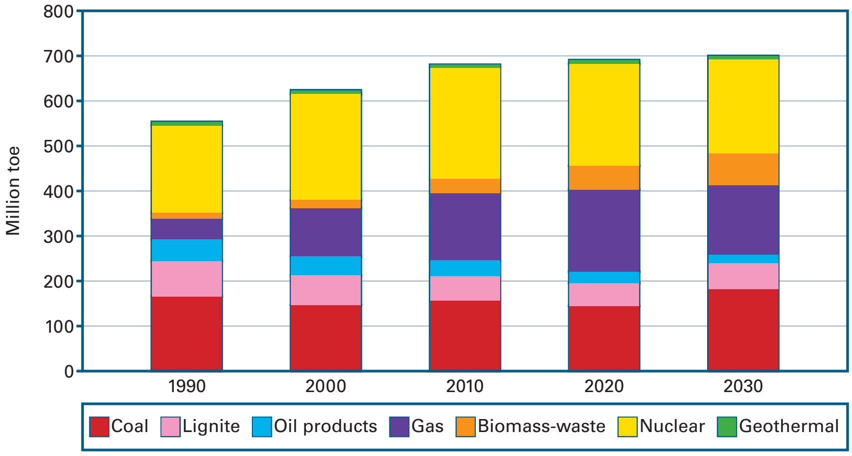
Correctly or incorrectly, virtually everybody in Europe agrees that

- Both in the short and long run, the current state of things is insecure.
- More diversification must be pursued.
- LNG may be a key step in that direction.

In fact LNG promises the safest,

Electricity generation in EU25

Fig. 2



Source: European Commission

Gas imports in the EU15

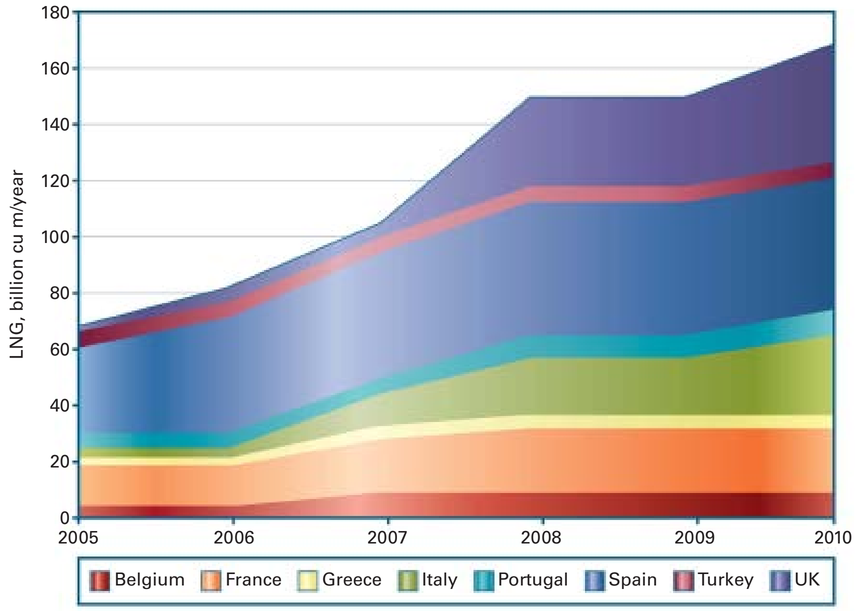
Table 1

Origin	2000	2002	2003	2004	Share 2004, %
	Million cu m				
Russia	78,484	68,807	74,160	76,709	32.5
Norway	46,714	61,351	66,707	67,212	28.5
Algeria	56,644	53,162	52,086	49,879	21.2
Nonspec. origin	6,808	15,966	18,700	24,899	10.6
Nigeria	4,283	6,276	8,746	10,538	4.5
Qatar	293	1,857	2,972	1,666	1.2
Total	**195,083**	**210,604**	**223,958**	**235,754**	**100.0**

Source: European Commission

EUROPEAN TERMINAL SENDOUT CAPACITY

Fig. 3



Source: OGJ's LNG Observer, Vol. 3, No. 2, p. 10; www.lngobserver.com.

quickest, and cheapest way to increase the number of gas providers, hence the flexibility of the system as a whole, and, at the same time, to increase the amount of imported gas, in order to address the declining domestic production and the increasing demand.

Finally, LNG is gas, i.e. the fossil fuel Europeans like (or tolerate) most. This explains why the European Commission has paid so much attention to the issue in the last few months, as well as the attempts to make it easier for oil companies to develop LNG terminals. In fact LNG could help new gas producers come on stream. It will also allow arbitrage of gas tankers, and therefore of natural gas, on the spot market in a way precluded by pipeline transportation.

In 2005, the EU25 imported 366 million cu m of gas via pipeline and just 48 via LNG. Considering how many proposed LNG terminals are in the process of being built, it is likely that the EU's import-terminal sendout capacity will increase to nearly 170 billion cu m in 2010 from less than 70 billion cu m (Fig. 3).[5]

Imported LNG will come mostly from North Africa and the Middle East. The growth in LNG demand is driven both by the desire to diversify energy sources and by supply constraint, as well as the fear that Russia in the future might not be as reliable as it has been thus far (OGJ, Apr. 9, 2007, p. 20).

Under this scenario, Europe faces two major challenges.

- One is about its ability to overcome the NIMBY (Not in My Back Yard) syndrome.

Local and environmentalist vetoes are a reality that companies and state authorities are rarely able to solve. There seems not to be a unique response.

The trick is to build a consensus within, and together with, local populations, showing them that the presence of an LNG terminal, either onshore or off, near where they live poses little or no threat, while being necessary to meet national gas and electricity demand—a trick as obvious as it is hard to achieve.

- The LNG market is growing so rapidly that a short-term bottleneck is already forming. The cost of building facilities has increased dramatically due to the rise of commodities price as well as to the surge of engineering, procurement, and construction costs that according to some estimates have risen to $600/ tonne/year or more today from $200/tonne/year in 2000.

Also, there is a scarcity of liquefaction plants, hence of LNG, and gas cargoes around the world, so that unless a terminal or customer has already signed or is about to sign long-term contracts with LNG producers and has secured cargoes, capacity short fall may be very real.

Both these problems will be more deeply examined presently with regard to Italy, which in a way suffers the same problems of Europe but more acutely.

The Italian job

The issue of energy security is particularly hot in Italy because of the country's heavy reliance on natural gas (Figs. 4 and 5), which is also due to a 1987 decision abandoning nuclear power (despite four nuclear power plants then operating) and its reluctance to increase the share of coal in electricity generation.

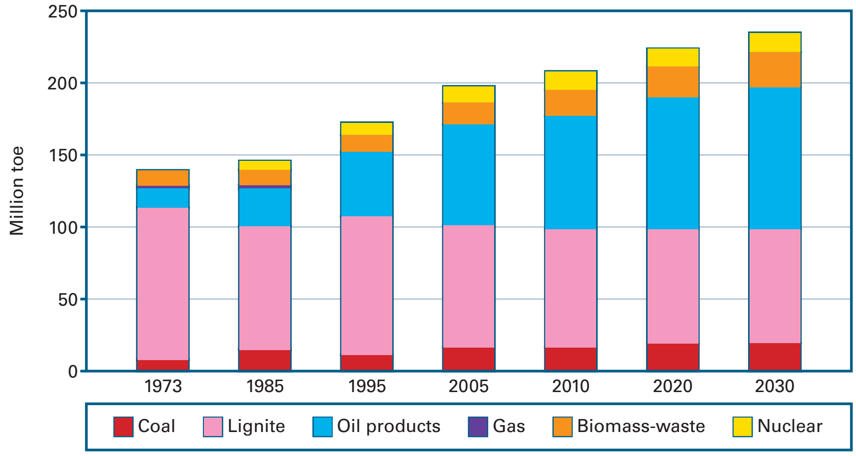
At the same time, Italy's demand of natural gas has grown so rapidly that new import capacity must be built. Companies operating throughout Italy are pursuing this goal both by increasing pipeline capacity (which would also increase dependence upon Russia, Algeria, and to a much lesser extent Libya) and by creating new LNG terminals. Virtually the entire political spectrum agrees that LNG terminals would help; that consensus ends, however, over where terminals should be located.

The share of imported gas has grown to 84% in 2004 from 12% in 1973 and will grow again up to 92% in 2010,[6] whereas domestic production is declining not only as a share of all consumption but also in absolute terms (to 8 billion cu m in 2010 from more than 15.3 billion cu m in 1973).[7]

In 2010, two thirds of natural gas needs will be met through imports from Russia and Algeria alone. Today only one LNG terminal is working in Italy, operated by the former monopoly ENI with capacity as low as 4 billion cu m/year, part of total natural gas consumption of around 86 billion cu m

PRIMARY ENERGY DEMAND IN ITALY

Fig. 4



Source: Reference 6.

in 2006.

Favorable economic and political conditions have convinced several companies, both Italian and foreign, to submit projects for new terminals. More than 10 projects have been approved or are in the process of being approved, although only three authorizations had been released by May 2007 and only one terminal can be expected to come on stream almost on time. By Italian standards, that means the process is likely to take less than or around 10 years (Table 2).

Paradoxically, if all the terminals were approved and actually built, a significant excess capacity would occur and Italy might become a sort of natural gas hub for Southern Europe, as among others the head of Italy's energy regulator Alessandro Ortis has been suggesting for a while. Introducing 2006 Annual Report of the regulator, Ortis said, "With regard to gas, Europe should be aiming to create at least two or three hubs, one in Italy for south central Europe."[8] In fact, by 2010 the aggregate supply of natural gas domestically produced, LNG, and imported via pipeline might be as high as 206-219 billion cu m, with a demand of 95-100 billion cu m.[9]

All approved terminals—Rovigo by ExxonMobil, Qatar Petroleum, and Edison; Brindisi by British Gas; and Livorno by OLT Offshore—have encountered problems, mostly due to local and environmentalist objections. People close to the companies say, however, they are confident that, despite some further delay and likely increase in the projected costs, Rovigo should come on stream by 2008, although it could have come on line at least 2 or 3 years sooner and thereby have prevented the January 2006 gas crisis had opposition to the terminal been less determined.

The Brindisi terminal is in a worse situation, partly because of bribery charges involving three former BG Group managers, who would have paid a €180,000 bribe for authorization to start works. The prosecutors arrested the three men as well as Brindisi's former mayor, who supported the project, and sealed the worksite.[10] That has led to seizure of the worksite. The terminal was originally to become operational in 2007, while today the deadline of 2010 is considered highly optimistic.

Interestingly, while the judicial action is a significant obstacle, the deadline would not be much different anyhow. In fact local, provincial, and regional elections in the last few years allowed opponents of the terminal to come into power and initiate a process that might lead to repeal of authorizations that originally were released.

The 2006 national elections and appointment of Alfonso Pecoraro Scanio, a leader of Italy's Green Party, as environment minister also contributed to making BG's way much tougher. In fact, Pecoraro Scanio, while claiming not to be against LNG terminals in principle, on several occasions questioned the validity of the authorizations for the Brindisi terminal.

Recently the Environment Ministry has requested BG to submit an environmental impact assessment, instead of an environmental impact study that had already been submitted because the law allowed it. Interestingly, from any practical purpose there is no difference in the amount of technical information required: The major difference is in the fact that the environmental impact assessment requires a popular consultation.

As far as the Livorno terminal is concerned, authorization has been released and preliminary works have started. But legal battles lie ahead.

An appeal has been filed from Edison, a competing company that is also trying to obtain authorization to build

PROJECTED LNG TERMINALS IN ITALY

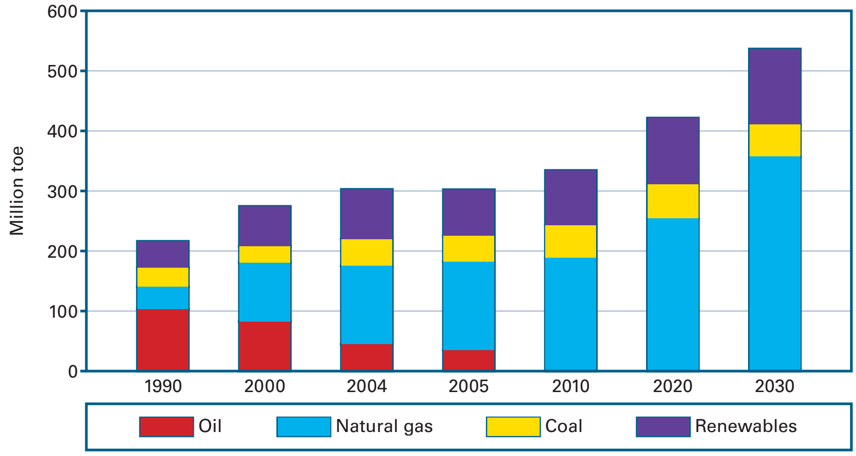
Table 2

Place	Operator(s)	Capacity, billion cu m/year	Authorization progress*
Rovigo	ExxonMobil, Qatar Petroleum, Edison	8.0	a
Rosignano	BP, Edison	3.0	s
Livorno offshore	OLT Offshore	3.0-4.0	a
Trieste offshore	Endesa Italia	8.0-12.0	s
Trieste Zaule	Gas Natural	8.0	t
Augusta	Erg, Shell	8.0-12.0	s
Brindisi	BG	8.0	a
Porto Empedocle	Nuove Energie	8.0	s
Taranto	Gas Natural	8.0	s
Gioia Tauro	LNG Terminal	4.0-8.0	s

*(a) authorized; (s) submitted; (t)to be submitted.

ELECTRICITY GENERATION IN ITALY

Fig. 5



Source: Reference 6.

an LNG plant near Livorno. According to Edison, OLT didn't have a right to take advantage of simplified procedures that were allowed. This claim has been supported by the chief legal officer of the Environmental Ministry, Sergio De Felice, in an unsolicited letter to the court.

With this claim, he is also implicitly claiming that the ministry itself was wrong in releasing the authorization. Among the arguments he makes, one is amusing: Since the part of the sea that lies before Livorno is part of the so-called Cetaceans' Sanctuary of the Mediterranean Sea,[11] an international treaty between Italy, France, and the Principality of Monaco aimed at protecting the cetaceans applies, France and Monaco should take part in an environmental impact assessment.[12] The terminal is supposed to be on stream in 2009, but it is still unclear if the schedule will be met.

Political problems are likely to interfere with other projects. At the same time policy makers are aware of what is at stake: not just a company's right to follow up the authorizations it has received, but more broadly Italy's ability to satisfy its own gas and electricity needs. Many politicians believe it was a mistake to give lower levels of government what in fact is veto power and suggest a return to centralization.

Others think the national government should take the lead in those infrastructures of strategic importance, including regasification terminals. To this end, a year ago was formed a "cabina di regia," i.e., a high-level working group on LNG terminals.

The group's members are Pecoraro Scanio, Economic Development Minister Pierluigi Bersani, Cabinet Undersecretary Enrico Letta, and later Infrastructure Minister Antonio Di Pietro. All of them, except for the environmental minister, support LNG terminals, including Brindisi.

The group has met a few times, the last in December 2006, without reaching any meaningful conclusion. Rumor in early summer was that it will not meet anymore. Significantly, both in Rovigo and Brindisi and presumably elsewhere the national leadership of most parties has been openly in favor, while local leaders were against.

There is, hence, a problem of making the regulatory process faster and more effective. In part it can be solved through appropriate reforms. The belief that centralization of the process might solve the problem, however, is probably excessively optimistic.

"It's not just about the legal side of the whole thing," said Massimo Romano, a former vice-president of Enel who is now chief executive officer of Sogin, a state-owned company created to dismantle Italy's nuclear sites.[13]

"Companies should invest more in creating a consensus within the local communities. Building a new plant is not only about bureaucratic requirements: It is about convincing people as well that they can get more benefits than costs, and showing them that companies pay much attention to the safety issues. We should communicate [to] them that we are not working against or despite them, but with and for them as well as for our shareholders."

Yet a legal problem does exists, which depends on the lack of certainties regarding the outcomes of the administrative processes as well as with the practical ability of local and regional governments to reverse their own decisions because of electoral changes.

Moreover, there is a broader problem in the legal framework. For example, last summer Pecoraro Scanio declared that four LNG terminals are enough for the country and named them, significantly omitting Brindisi. This is inconsistent with a liberalized market, where what is "too much" is decided by the market and whether a terminal should be operating depends upon the ability of the owners to meet administrative criteria that are known in advance.

Then, if the imported gas is "too much," the price will fall and some companies will post losses in their budgets, but addressing this problem is not the government's business. By the same token, the criticism that only a minority of the proposed LNG terminals have already secured a long-term contract for natural gas should not be a government's concern.✦

References

1. Article 175 of the consolidated version of the Treaty on European Union and of the Treaty Establishing the European Community (available online at http://eur-lex.europa.eu/LexUriServ/site/en/oj/2006/ce321/ce32120061229en00010331.pdf) provides that "by way of derogation" from the normal decision-making

procedures, "measures significantly affecting a Member State's choice between different energy sources and the general structure of its energy supply" shall be adopted by "the Council, acting unanimously on a proposal from the Commission and after consulting the European Parliament, the Economic and Social Committee and the Committee of the Regions."

The requirement of unanimous decisions means that any member state has veto power over common energy policy, the effect of which is that energy policy is kept under national sovereignty.

2. An Energy Policy for Europe, Commission of the European Communities, 2007; http://eur-lex.europa.eu/LexUriServ/site/en/com/2007/com2007_0001en01.pdf, p. 4.

3. An Energy Policy for Europe, Commission of the European Communities, 2007; p. 11.

4. http://www.epa.gov/solar/emissions.htm.

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6. Clô, Alberto, Materiali per una politica energetica e ambientale, Bologna, Rie, 2006, p. 39. An earlier version of the study is available online at http://studi.sede.enea.it/documentazione/rie.pdf; the data here referred to are in Table 13, p. 30.

7. Ibid.

8. Ortis, Alessandro, "Annual Report on Regulatory Activities and the State of Services. Introduction by the President," Autorità per l'energia elettrica e il gas, 2006, http://www.autorita.energia.it/inglese/annual_report/pres_ra_06.pdf, p. 8.

9. Clô, Alberto, Materiali per una politica energetica e ambientale, pp. 37-38. The estimate is not available in the online version.

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11. See http://www.santuariodeicetacei.it/whales.nsf/EnglishHome.

12. "Guai in vista per progetto del rigassificatore Olt," http://www.intoscana.it/intoscana/vivere_in_toscana.jsp?intenzione=viverein&id_categoria=5&tipologia=articoli&id_sottocategoria=1228&id=98024&typeAsset=Articolo&language=it.

13. Private interview.

The author

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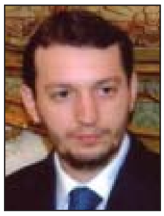


Equipment/Software/Literature

New meter measures distance, level, volume

Here's the OPTIFLEX 1300 C TDR level meter, an instrument that promises accurate measurement of distance, level and volume of liquids and solids.

Its high signal dynamics translate to measurements that are accurate and stable. Despite disturbances such as strongly agitated surfaces, the meter will clearly locate the product's true surface and will continue to provide accurate measurements, the company points out.

Sharper pulses allow the meter to detect and measure interfaces as thin as a 2-in. film of oil on water in a large tank. The sharper pulses also allow better repeatability of results, the firm says. OPTIFLEX measures down to a dielectric of 1.4 (and even 1.1 under certain conditions).

The instrument is available with five probes—single rod, double rod, single cable, double cable, and coaxial, helping ensure that the device can handle virtually any application. The unit's maximum measuring range is from 13 ft to 115 ft, depending on the probe type.

Installation and setup of the tool requires the user to simply fit the gauge to the tank, wire it, and turn it on, after which the device will then run a self-diagnostic test to ensure proper operation. A setup wizard takes the user through a simple series of questions to define the tank and the product to be measured. A help screen is also available to assist in setup and any subsequent operation. The instrument also features a device type manager—a device driver that makes functionality available independent from the field bus protocol.

Source: **Krohne Inc.**, 7 Dearborn Rd., Peabody, MA 01960.

Literature discusses oil field tubulars

New literature details DUOLINE 20 corrosion resistant oil field tubulars for water injection and disposal of salt water or other environmentally degrading corrosive fluids, including case studies of its installations during the past 20 years.

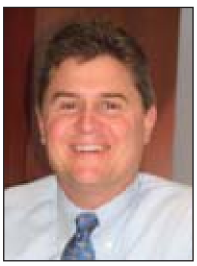
The filament-wound glass-reinforced epoxy liner is installed in oil field tubulars that are used in corrosive services.

Source: **Duoline Technologies**, 9019 N. Co. Rd. West, Odessa, TX 79764.

Services/Suppliers

AMEC Paragon

Houston, has announced the appointment of Terri Ivers as president. Simon Naylor, who previously held dual roles as president of both AMEC Paragon and all of AMEC's oil and gas business in the Americas, will remain in the Houston office. He will have expanded duties as president of AMEC's Natural Resources (Americas) business, which includes oil and gas, mining and metals, oil sands, and other energy-related services.


Ivers

Ivers, who has nearly 30 years of experience in the global oil and gas industry, joins AMEC Paragon from Alliance Wood Group Engineering, where he was chief operating officer. He previously was with Kellogg Brown & Root for 27 years. He earned his BS degree in mechanical engineering from the University of Houston.

AMEC Paragon, a part of AMEC's Natural Resources business, provides engineering, materials management, and construction management services to the oil and gas, pipeline, and midstream industries. Its specialties include onshore and offshore production facilities, offshore platforms, onshore and offshore pipelines, floating production systems, and subsea systems.

Entrepose Contracting

Colombes, France, has announced its acquisition of AMEC Spie Capag SA from the British group, AMEC PLC. The group has been renamed Spie Capag.

The two groups' projects complement each other geographically, with Spie Capag's projects mainly in Europe, Asia, and the Middle East, and Entrepose Contracting's in Africa, and Europe.

Entrepose Contracting is an independent contractor specializing in the design and construction of turnkey projects for the oil, gas, and energy industries.

Spie Capag is a leading pipe laying contractor with head offices in Cergy Pontoise, France.

Southwestern Drilling Co. LP

Plano, Tex., has named Richard A. Zartler as general manager.

Zartler has held executive positions with Western Co., Grace Energy Corp., and Grace Drilling Co. during his 23-year oil field career prior to joining Southwestern.

Southwestern Drilling Co. LP operates in east and north central Texas.

Implicit Monitoring Solutions LP

Dallas, has announced the appointment of Mike Kolb as vice-president of sales operations. Kolb brings more than 20 years of satellite communication and sales operation expertise to the position.

Implicit Monitoring Solutions LP is a leading provider of remote asset performance and control monitoring services for the oil and gas industry.

Statistics

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

OGJ GASOLINE PRICES

	Price ex tax 6-27-07	Pump price* 6-27-07	Pump price 6-28-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	264.7	304.4	291.2
Baltimore	259.2	301.1	298.4
Boston	250.6	292.5	292.4
Buffalo	243.6	303.7	301.5
Miami	255.4	305.7	304.8
Newark	254.8	287.7	290.2
New York	243.4	303.5	300.6
Norfolk	255.8	293.4	293.1
Philadelphia	257.0	307.7	306.2
Pittsburgh	245.4	296.1	290.4
Wash., DC	264.2	302.6	311.1
PAD I avg.	254.0	299.8	298.2
Chicago	278.3	329.2	323.0
Cleveland	236.3	282.7	283.0
Des Moines	263.8	304.2	270.9
Detroit	270.3	319.5	286.9
Indianapolis	268.0	313.0	280.1
Kansas City	267.5	303.5	270.9
Louisville	269.7	306.6	288.2
Memphis	259.0	298.8	282.6
Milwaukee	258.8	310.1	287.5
Minn.-St. Paul	245.5	285.9	278.5
Oklahoma City	253.4	288.8	263.1
Omaha	246.7	293.1	277.0
St. Louis	271.2	307.2	262.1
Tulsa	254.3	289.7	260.4
Wichita	261.0	304.4	269.2
PAD II avg.	260.3	302.5	278.9
Albuquerque	278.4	314.8	283.5
Birmingham	253.2	291.9	278.2
Dallas-Fort Worth	250.7	289.1	288.2
Houston	244.6	283.0	287.3
Little Rock	251.0	291.2	276.9
New Orleans	263.4	301.8	281.9
San Antonio	249.3	287.7	272.9
PAD III avg.	255.8	294.2	281.3
Cheyenne	260.2	292.6	272.7
Denver	273.0	313.4	292.2
Salt Lake City	272.1	315.0	297.3
PAD IV avg.	268.4	307.0	287.4
Los Angeles	256.8	315.3	336.4
Phoenix	266.4	303.9	308.3
Portland	269.7	313.0	303.2
San Diego	270.2	328.7	343.3
San Francisco	267.7	326.2	341.7
Seattle	251.9	304.3	320.2
PAD V avg.	263.8	315.2	325.5
Week's avg.	**259.0**	**302.6**	**291.6**
June avg.	**265.9**	**309.4**	**288.4**
May avg.	**264.1**	**307.6**	**288.5**
2007 to date	**222.0**	**265.6**	—
2006 to date	**213.9**	**257.0**	—

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

REFINED PRODUCT PRICES

	6-22-07 ¢/gal		6-22-07 ¢/gal
Spot market product prices			
		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	203.90
New York Harbor	225.93	Gulf Coast	201.15
Gulf Coast	221.55	Gas oil	
Los Angeles	230.60	ARA	200.49
Amsterdam-Rotterdam-		Singapore	193.69
Antwerp (ARA)	206.93		
Singapore	200.60	Residual fuel oil	
Motor gasoline		New York Harbor	127.69
(Reformulated-regular)		Gulf Coast	136.31
New York Harbor	232.55	Los Angeles	145.11
Gulf Coast	227.05	ARA	117.78
Los Angeles	242.60	Singapore	134.05

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

BAKER HUGHES RIG COUNT

	6-29-07	6-30-06
Alabama	7	4
Alaska	6	8
Arkansas	49	24
California	39	34
Land	38	32
Offshore	1	2
Colorado	109	89
Florida	1	0
Illinois	0	0
Indiana	3	0
Kansas	10	17
Kentucky	8	6
Louisiana	177	187
N. Land	57	56
S. Inland waters	22	20
S. Land	34	35
Offshore	64	76
Maryland	0	0
Michigan	1	2
Mississippi	13	8
Montana	19	25
Nebraska	1	0
New Mexico	86	96
New York	5	6
North Dakota	35	30
Ohio	13	6
Oklahoma	192	186
Pennsylvania	13	17
South Dakota	4	1
Texas	827	746
Offshore	12	10
Inland waters	0	4
Dist. 1	21	22
Dist. 2	26	24
Dist. 3	65	64
Dist. 4	94	76
Dist. 5	174	131
Dist. 6	125	109
Dist. 7B	33	42
Dist. 7C	55	42
Dist. 8	102	91
Dist. 8A	26	30
Dist. 9	33	33
Dist. 10	61	68
Utah	39	43
West Virginia	35	25
Wyoming	73	102
Others—NV-3; TN-3; VA-3; WA-1	10	4
Total US	**1,775**	**1,666**
Total Canada	**231**	**473**
Grand total	**2,006**	**2,139**
Oil rigs	281	302
Gas rigs	1,489	1,359
Total offshore	78	89
Total cum. avg. YTD	**1,746**	**1,578**

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	6-29-07 Rig count	6-29-07 Percent footage*	6-30-06 Rig count	6-30-06 Percent footage*
0-2,500	60	6.6	59	3.3
2,501-5,000	117	52.9	90	42.2
5,001-7,500	243	22.2	226	18.5
7,501-10,000	416	3.1	370	2.9
10,001-12,500	459	1.7	400	2.0
12,501-15,000	259	—	257	—
15,001-17,500	109	0.9	101	—
17,501-20,000	69	—	84	—
20,001-over	36	—	24	—
Total	**1,768**	**8.0**	**1,611**	**6.2**
INLAND	41		44	
LAND	1,657		1,489	
OFFSHORE	70		78	

*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]6-29-07	[2]6-30-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	20
Alaska	760	781
California	660	685
Colorado	49	61
Florida	7	6
Illinois	30	28
Kansas	93	99
Louisiana	1,347	1,327
Michigan	14	15
Mississippi	48	48
Montana	90	98
New Mexico	163	159
North Dakota	104	112
Oklahoma	163	171
Texas	1,310	1,350
Utah	44	47
Wyoming	142	123
All others	60	76
Total	**5,102**	**5,206**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	**6-29-07**
Alaska-North Slope 27°	56.11
South Louisiana Sweet	74.25
California-Kern River 13°	59.65
Lost Hills 30°	69.25
Wyoming Sweet	66.68
East Texas Sweet	66.75
West Texas Sour 34°	60.40
West Texas Intermediate	67.25
Oklahoma Sweet	67.25
Texas Upper Gulf Coast	64.00
Michigan Sour	60.25
Kansas Common	66.25
North Dakota Sweet	63.00

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

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

WORLD CRUDE PRICES

$/bbl[1]	**6-22-07**
United Kingdom-Brent 38°	72.05
Russia-Urals 32°	68.87
Saudi Light 34°	66.85
Dubai Fateh 32°	66.78
Algeria Saharan 44°	72.51
Nigeria-Bonny Light 37°	73.20
Indonesia-Minas 34°	69.45
Venezuela-Tia Juana Light 31°	67.09
Mexico-Isthmus 33°	66.98
OPEC basket	68.98
Total OPEC[2]	68.51
Total non-OPEC[2]	68.04
Total world[2]	68.29
US imports[3]	65.69

[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]

	6-22-07	6-15-07	Change
	Bcf		
Producing region	853	832	21
Consuming region east	1,224	1,157	67
Consuming region west	366	355	11
Total US	**2,443**	**2,344**	**99**
	Mar. 07	**Mar. 06**	**Change, %**
Total US[2]	**1,603**	**1,692**	**–5.3**

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Apr. 2007	Mar. 2007	4 month average production 2007	4 month average production 2006	Change vs. previous year Volume	Change vs. previous year %	Apr. 2007	Mar. 2007	Cum. 2007
	Crude, 1,000 b/d						Gas, bcf		
Argentina	627	633	630	626	4	0.6	128.4	126.5	487.68
Bolivia	45	45	45	45	–1	–1.1	41.0	43.0	163.00
Brazil	1,739	1,769	1,751	1,703	47	2.8	24.0	29.0	107.00
Canada	2,625	2,772	2,643	2,501	142	5.7	499.1	517.2	2,055.80
Colombia	520	518	519	530	–11	–2.1	17.5	18.0	69.50
Ecuador	502	482	500	547	–47	–8.6	0.3	0.3	1.19
Mexico	3,182	3,182	3,164	3,351	–187	–5.6	179.0	183.0	702.52
Peru	109	103	112	111	1	0.6	6.0	6.6	23.69
Trinidad	125	125	124	151	–28	–18.2	114.0	118.0	452.31
United States	5,127	5,178	5,162	5,045	118	2.3	1,621.0	1,674.0	6,431.00
Venezuela[1]	2,370	2,390	2,420	2,630	–210	–8.0	70.0	75.0	295.00
Other Latin America	80	82	80	79	1	1.7	7.2	7.5	29.09
Western Hemisphere	**17,051**	**17,280**	**17,148**	**17,319**	**–171**	**–1.0**	**2,707.5**	**2,798.1**	**10,817.79**
Austria	17	17	17	17	—	0.3	5.4	5.6	21.50
Denmark	316	321	315	333	–17	–5.2	18.9	16.7	97.63
France	19	20	19	22	–3	–14.7	1.7	3.3	11.30
Germany	68	70	70	72	–3	–3.6	49.9	55.0	214.96
Italy	107	108	109	115	–6	–5.0	29.0	30.0	117.80
Netherlands	42	40	43	29	13	45.3	350.0	370.0	1,495.00
Norway	2,427	2,391	2,426	2,574	–148	–5.7	291.4	268.4	1,104.74
Turkey	41	41	40	41	—	–1.0	—	—	6.50
United Kingdom	1,583	1,575	1,591	1,655	–64	–3.8	240.8	268.4	989.64
Other Western Europe	4	4	4	4	—	–1.3	2.1	2.2	10.46
Western Europe	**4,625**	**4,587**	**4,634**	**4,861**	**–227**	**–4.7**	**989.2**	**1,019.6**	**4,069.53**
Azerbaijan	800	750	813	575	238	41.3	21.0	28.0	93.00
Croatia	16	16	16	17	–1	–5.3	5.9	6.1	24.15
Hungary	17	17	17	18	–1	–7.5	7.5	7.7	30.28
Kazakhstan	1,350	1,250	1,250	1,005	245	24.4	32.0	80.0	272.00
Romania	98	98	98	100	–2	–2.3	17.4	18.0	70.40
Russia	9,590	9,680	9,680	9,375	305	3.3	1,900.0	2,000.0	7,900.00
Other FSU	450	400	413	525	–113	–21.4	450.0	480.0	1,810.00
Other Eastern Europe	49	49	49	48	1	1.6	87.4	74.3	355.56
Eastern Europe and FSU	**12,370**	**12,260**	**12,335**	**11,663**	**671**	**5.8**	**2,521.1**	**2,694.1**	**10,555.39**
Algeria[1]	1,340	1,330	1,333	1,360	–28	–2.0	275.0	285.0	1,100.00
Angola[1]	1,679	1,658	1,634	1,425	208	14.6	2.5	2.5	9.80
Cameroon	83	80	84	89	–6	–6.2	0.0	0.0	0.00
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	660	660	660	695	–35	–5.0	40.6	42.0	162.60
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.24
Gabon	230	230	230	240	–10	–4.2	0.3	0.3	1.20
Libya[1]	1,690	1,690	1,693	1,675	18	1.0	21.0	22.0	84.50
Nigeria[1]	2,250	2,150	2,233	2,198	35	1.6	75.0	75.0	298.00
Sudan	480	450	458	395	63	15.8	—	—	—
Tunisia	104	95	95	65	30	46.3	6.7	7.0	27.30
Other Africa	262	262	262	272	–10	–3.6	10.0	10.2	39.82
Africa	**9,357**	**9,185**	**9,259**	**8,994**	**265**	**3.0**	**431.1**	**444.0**	**1,723.46**
Bahrain	171	171	171	175	–4	–2.5	23.3	22.3	96.53
Iran[1]	3,970	4,030	3,920	3,808	113	3.0	250.0	265.0	1,005.00
Iraq[1]	2,100	2,000	1,945	1,788	158	8.8	5.0	5.0	20.00
Kuwait[1,2]	2,395	2,425	2,425	2,514	–89	–3.5	30.0	31.0	120.00
Oman	710	720	720	760	–40	–5.3	55.0	58.0	223.00
Qatar[1]	800	780	798	823	–25	–3.0	110.0	110.0	435.00
Saudi Arabia[1,2]	8,465	8,405	8,473	9,276	–804	–8.7	150.0	155.0	605.00
Syria	390	390	393	440	–48	–10.8	15.5	16.0	61.90
United Arab Emirates[1]	2,560	2,560	2,565	2,628	–63	–2.4	130.0	135.0	520.00
Yemen	360	360	358	343	15	4.4	—	—	—
Other Middle East	—	—	—	—	—	–26.6	7.1	7.5	31.39
Middle East	**21,921**	**21,841**	**21,766**	**22,553**	**–787**	**–3.5**	**775.9**	**804.7**	**3,117.82**
Australia	460	386	446	354	92	25.9	120.0	105.3	442.90
Brunei	180	180	184	204	–20	–9.8	34.0	35.0	135.35
China	3,759	3,695	3,756	3,691	65	1.8	188.9	200.2	800.27
India	684	696	692	667	25	3.7	80.0	85.1	318.82
Indonesia[1]	840	850	848	923	–75	–8.1	175.0	183.0	708.00
Japan	18	19	19	17	1	7.0	12.2	11.4	45.92
Malaysia	720	740	745	760	–15	–2.0	130.0	138.0	533.00
New Zealand	20	20	18	16	2	12.9	13.0	13.6	47.10
Pakistan	67	65	66	66	—	–0.1	114.9	120.0	462.85
Papua New Guinea	50	50	53	58	–6	–9.5	0.5	0.5	1.95
Thailand	217	222	210	217	–7	–3.3	74.6	77.8	293.12
Viet Nam	350	350	343	350	–8	–2.1	14.5	15.0	58.00
Other Asia–Pacific	38	38	38	32	6	18.7	85.2	89.5	344.00
Asia–Pacific	**7,404**	**7,310**	**7,416**	**7,355**	**61**	**0.8**	**1,042.7**	**1,074.5**	**4,191.28**
TOTAL WORLD	**72,728**	**72,463**	**72,557**	**72,744**	**–187**	**–0.3**	**8,467.6**	**8,835.0**	**34,475.27**
*OPEC	30,459	30,268	30,284	29,620	664	2.2	1,291.0	1,341.0	5,190.50
North Sea	4,351	4,305	4,351	4,578	–227	–5.0	655.8	664.2	2,639.28

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

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Ethanol's fans are dodging the food-cost issue

Consumers worry more about rising prices of corn flakes and milk than about the extent to which the cost of one ingredient affects all food.

Ethanol's tireless propagandists, however, are focusing on corn's contribution to the Consumer Price Index for food to imply that their favorite fuel deserves no blame.

The Renewable Fuel Association trumpets a report concluding that the price of corn, ethanol's main ingredient, has much less effect than the price of energy does on all food prices in the CPI.

The Editor's Perspective

by Bob Tippee, Editor

"Increasing petroleum prices have about twice the impact on consumer food prices as equivalent increases in corn prices," says report author and economist John M. Urbanchuk, director of LEGC LLC.

RFA Pres. Bob Dinneen calls references to ethanol's link with food prices "baseless scare tactics" and says, "While it is true increased ethanol production is creating a real market-driven price for corn, this [Urbanchuk's] report clearly presents the undeniable facts: Energy prices, not ethanol, are responsible for much of the increase in the price of food."

This is a dodge. Of course energy costs affect food prices. And it should surprise no one that an energy-price rise affects aggregate food prices more than does a comparable increase in the price of a single grain—the core message of Urbanchuk's report.

But those assertions are irrelevant to the issue, which is that the ethanol mandate is raising prices of corn and of foods associated with it beyond increases attributable to energy. Urbanchuk addresses not ethanol's effect on the price of corn but rather corn's effect on all food in the CPI. He still concludes that "the days of cheap corn are more likely than not over."

The ethanol mandate undeniably stokes that outlook and its portents for the prices of foods based on corn. It also helps push up the energy prices onto which ethanol fans are trying to shift blame.

Congress launched these assaults on consumers on the basis of flawed energy and environmental claims in order to enrich corn growers and distillers. In a political climate where this can happen, "scare tactics" are, in fact, appropriate.

(Online June 29, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude tops $70/bbl on NYMEX

The August contract for benchmark US light, sweet crudes pushed past $70/bbl June 29 on the New York Mercantile Exchange to its highest level in 10 months due to declines in US gasoline and distillate fuel supplies despite an increase in refining capacity.

That same contract traded as high as $70.52/bbl June 28 on NYMEX before closing at $69.57/bbl, up 60¢ for the day. On June 29, it climbed as high as $71.68/bbl in intraday trading before closing at $70.68/bbl. It was the first time a front-month crude contract closed above the psychological $70/bbl mark since August 2006.

"Crude oil has now been able to confirm a break out of the $70/bbl barrier that was keeping it in check since the beginning of the second quarter. If it is able to confirm the momentum, it would now set the next technical target at $75/bbl in a repeat of the July 2006 dynamics," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. Trading was volatile June 28-29 due to "an oil triple witching with the [simultaneous] end of the week, end of the quarter, and expiry of the July product contracts," Jakob said.

The crude price dipped slightly in early trading July 2 but remained near a 10-month high after three consecutive weekly gains.

News from Iraq that a pipeline linking the southern oil fields to the Baghdad refinery was damaged by a bomb explosion helped push up energy prices in New York. "While the damaged pipeline shouldn't significantly hinder Iraqi supplies, it underscores the tense environment that contributes to the geopolitical risk premium in crude prices," said analysts in the Houston office of Raymond James & Associates Inc.

US inventory surprise

On June 27, the US Energy Department's Energy Information Administration reported gasoline inventories dropped 700,000 bbl to 202.6 million bbl in the week ended June 22 in conflict with the consensus expectation of 1 million bbl increase. It was the first draw on US gasoline inventories in 8 weeks. Distillate stocks fell 2.3 million bbl to 120.4 million bbl against the consensus expectation of a 600,000 bbl build. Crude inventories increased by 1.6 million bbl to 350.9 million bbl in the same week, reaching levels not seen since May 1998.

Imports of crude into the US fell 290,000 b/d to 10.5 million b/d in the week ended June 22. Yet the input of crude into US refineries increased by 408,000 b/d to 15.4 million b/d, as refining capacity utilization increased to 89.4% from 87.6% the prior week. Nonetheless, US gasoline production was "relatively flat" at 9.3 million b/d while distillate fuel production was "unchanged" at 4 million b/d, EIA reported.

The price of the August crude contract "moved up 80¢/bbl in the 60 seconds that followed the release of the DOE report and managed afterwards to hold and improve on those gains," stopping the momentum of previous price erosion, Jakob said. It traded as high as $69.36/bbl before closing at $68.97/bbl, up by $1.20 June 27 to recoup much of its loss from the previous session.

"With both the US refinery utilization rate and gasoline inventory levels remaining well below the 5-year average, the draw in gasoline supplies has reignited concerns about adequate inventory levels," said Raymond James analysts.

Paul Horsnell at Barclays Capital Inc., London, reported, "US oil product inventories are now at the greatest deficit to their 5-year average since 2004." Assessing the gasoline market, he said, "Strong demand, falling imports, and flat output is not a great combination, and we continue to look for gasoline prices to push up towards their second peak of the driving season. Gasoline demand for June-to-date is averaging 9.551 million b/d, which is just 34,000 b/d lower than the all-time record for any month set last August."

"Despite US retail gasoline prices having averaged more than $3/gal during the past several weeks, demand remained 1.4% above comparable year-ago levels," said Eitan Bernstein of Friedman, Billings, Ramsey & Co. Inc., Arlington, Va.

Meanwhile, improved refinery utilization rates will help pull down the huge crude stockpiles in Cushing, Okla. "As these stockpiles continue to fall, West Texas Intermediate prices may soon exceed prices of Brent crude as they have historically done," said Raymond James analysts. In recent weeks, North Sea Brent crude has sold at an unusual premium to WTI.

Jakob, said, "No other energy commodity was able to follow the strong pace of WTI [in June 28 trading]. Individual and refining cracks continued to erode, and the Brent premium to WTI corrected sharply lower" during that week.

(Online July 2, 2007; author's e-mail: samf@ogjonline.com)