Week of July 7, 2008/US$10.00

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Oil Sands Update

Silent disruption limiting oil supply
Field redevelopment and storm impact assessed for US gulf
High ethane demand tightens coproduct propylene supply
Increased Texas-to-Southeast deliveries affect gas price bases

OIL&GAS JOURNAL®

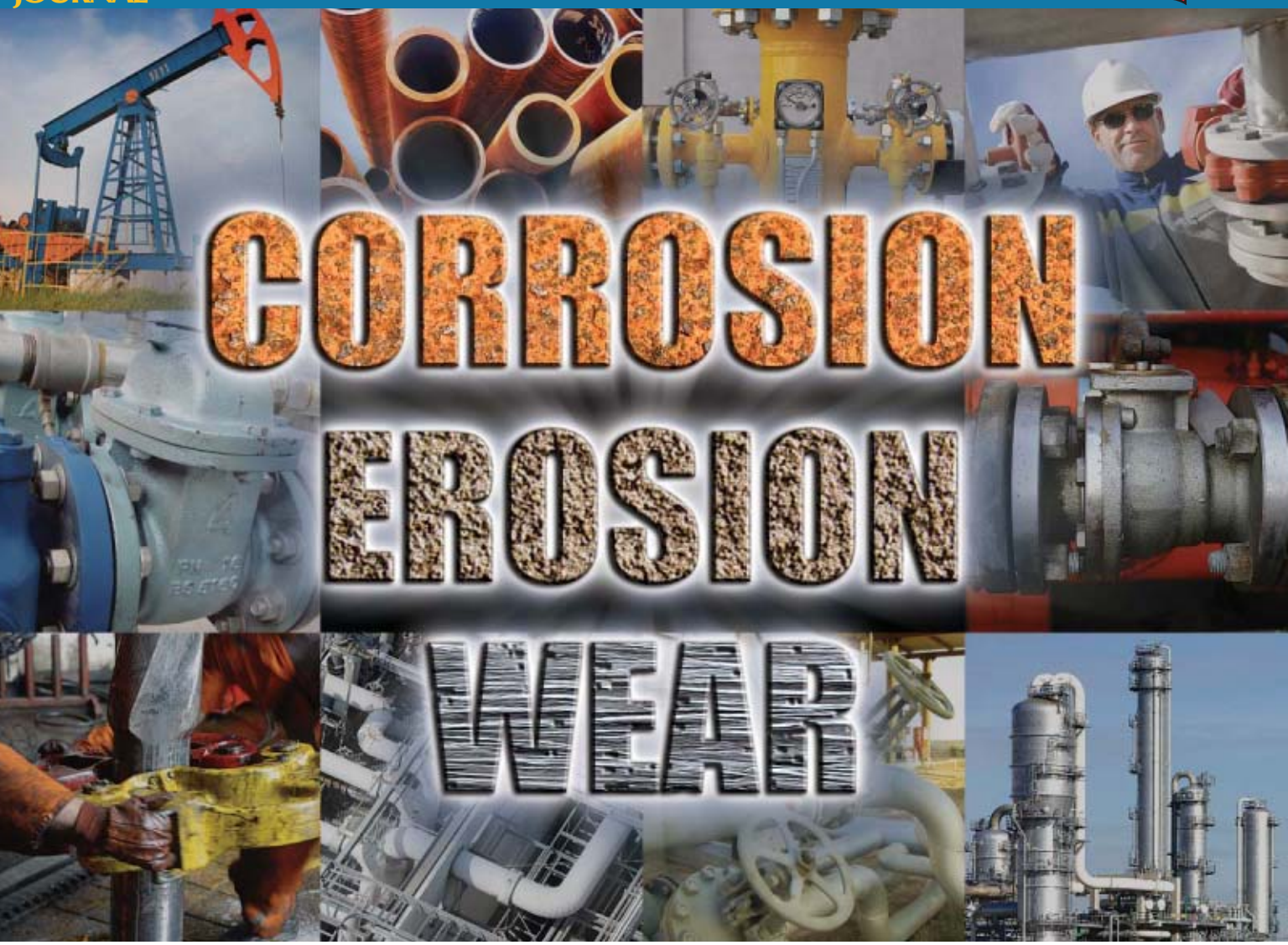
July 7, 2008
Volume 106.25

OIL SANDS UPDATE

REGULAR FEATURES

COVER

Foster Creek, the first commercial steam-assisted gravity drainage (SAGD) project to come on stream, began producing bitumen in 2001. Production is from the McMurray formation in the southern part of Alberta's Athabasca oil sands region. The EnCana Corp.-operated project currently produces about 30,000 b/d of bitumen. With future expansions, production may reach 150,000 b/d. Two articles in the week's special report, Oil Sands Update, starting on p. 51, describe the latest status of the reserves, production, and marketing of the vast bitumen resources found in the oil sands of Alberta. Photo from EnCana.



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It's a technological breakthrough...
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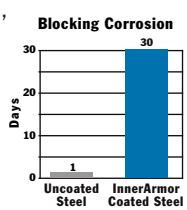
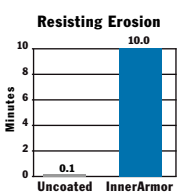
And InnerArmor has no porosity, no pinholes. So it creates a virtually impenetrable barrier against corrosion, erosion and wear.

Stopping corrosion
In NACE-standard TM185 sour autoclave testing, for example, InnerArmor withstood the maximum 30-day test—sustaining *no* attack or undercut.

While uncoated steel only lasted a single day!



Standing up to erosion
In the ASTM-standard G76 abrasive air-jet test, again, InnerArmor was easily able to go the full ten minutes—with *zero* surface damage.



By comparison, on uncoated steel the surface erosion began after only a few seconds.

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For example, the wear rate on InnerArmor-coated stainless steel (with a 25N load) is less than *half* that of uncoated stainless!

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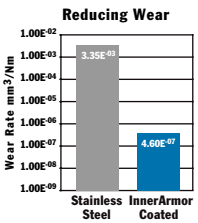

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General Interest

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Drilling & Production

Processing

Transportation

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July 7, 2008

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General Interest — Quick Takes

Brazil plans oil law changes, oil management firm

Brazil's Mines and Energy Minister Edison Lobao plans to propose to President Luiz Inacio Lula da Silva the creation of a new state-run firm that would manage oil discoveries made in recent months in the subsalt layer of the Santos basin.

Lobao, who is responsible for developing a new model for oil exploration, is scheduled to present a study on the matter within 60 days, according to a report in Valor Economico business newspaper.

The paper reported that Lobao—after considering suggestions received in recent weeks—is convinced that the best solution for the country is to adopt a production-sharing regime, which would require legislation changes to Brazil's Petroleum Law.

In countries where this regime has been implemented, the paper said, state-owned companies have the role of deciding on production levels and supervising exploration in fields.

According to Lobao, the new state firm would neither drill wells nor extract oil but would hire government-owned Petroleo Brasileiro SA or other firms as service suppliers.

Australia's Offshore Petroleum Act 2006 in effect

The Petroleum (Submerged Lands) Act 1967 (PSLA)—Australia's primary legislation for the administration of its offshore petroleum resources since the riches of Bass Strait were discovered and first produced in the 1960s—was replaced July 1 with the new Offshore Petroleum Act 2006 (OPA).

Martin Ferguson, resources and energy minister, says the new act will make the legislation easier to understand and will reduce costs of compliance and administration for industry and government.

However, he said there are no changes to major policies or the current management regime.

The OPA received Royal Assent in March 2006 but could not be proclaimed until all states and territories had updated their offshore petroleum legislation. This was completed when Tasmania amended its legislation on June 16.

UK oil participants agree to share best practices

Offshore operators and contractors in the UK have agreed to share experiences and best practices on the design and development of new learning products and services under a major partnership to help address the skills shortage in the oil and gas industry.

OPITO-The Oil & Gas Academy and the Engineering Construction Industry Training Board (ECITB) will work with Oil & Gas UK and the Offshore Contractors Association.

"As well as allowing for improved quality and transferability of the skills pool leading to increased safety and overall business performance, the new alliance will also provide a combined menu of skills and training solutions for operators and contractors," OPITO said.

ECITB Chief Executive David Edwards said, "The changing business models within the industry means that more alignment is needed to address the skills priorities. Working together will make this happen more quickly and effectively whilst ensuring duplication of effort and cost is eliminated over time." ✦

Exploration & Development — Quick Takes

Lukoil, ConocoPhillips start W. Siberia field

A joint venture of OAO Lukoil and ConocoPhillips has begun first-stage oil and gas production from Yuzhno Khylchuyu field in the Nenets Autonomous District of northwestern Siberia, Russia.

The first 32 development wells in the arctic field are producing oil through a 98-mile, 21-in. pipeline to the Varandey oil export terminal on Kola Bay on the Barents Sea. The field's oil is 35.5° gravity with 0.71% sulfur, better than Russia's 32° gravity, 1.3% Urals export blend.

Discovered in 1981, Yuzhno Khylchuyu field has more than 500 million bbl of proved oil reserves. It is considered one of the largest fields in Russia's Timan Pechora oil and gas province and the anchor field for an overall $4 billion in developments by the joint venture.

Interests in the OOO Naryanmarneftegaz joint venture, established in 2005, are Lukoil 70% and ConocoPhillips 30%.

Besides the 32 wells, the first stage comprises a 3.8 million tonne/year oil treatment unit; an oil desulfurization unit; a 40,000 cu m tank farm; a pump station; a 17-mile, 11-in. Yareyu-Yuzhno Khylchuyu high-pressure gas pipeline; a 370 million cu m gas treatment plant; a 125-Mw power supply complex; and 178 miles of 220 kv high-voltage transmission lines.

Second-stage start-up planned for December involves 32 new wells, doubling the capacity of the oil treatment unit, and adding a compressor station and sulfur disposal and storage facilities.

Design capacity is projected at 150,000 b/d in 2009. Crude is to be loaded from floating storage at Varandey onto 70,000 dwt tankers for shipment to Europe and North America.

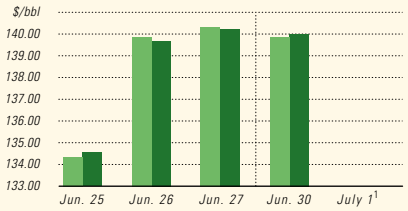
Tullow Oil makes Uganda oil, gas discovery

Tullow Oil PLC discovered oil and gas within the Ngege-1 exploration well on the northern part of Block 2 in Uganda's Lake Albert Rift basin 41 km northeast of the Taitai-1 discovery well.

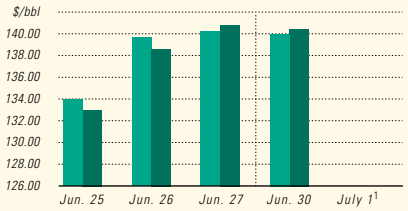
The find marks a new deltaic play fairway with high-quality res-

Industry Scoreboard

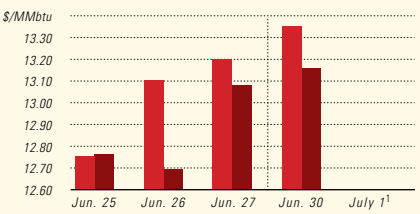
IPE BRENT / NYMEX LIGHT SWEET CRUDE



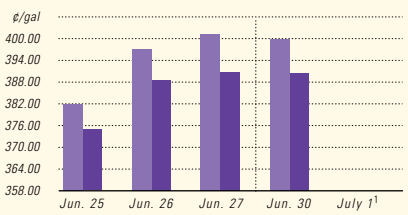
WTI CUSHING / BRENT SPOT



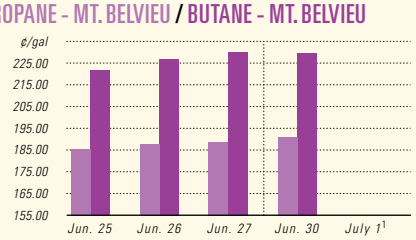
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



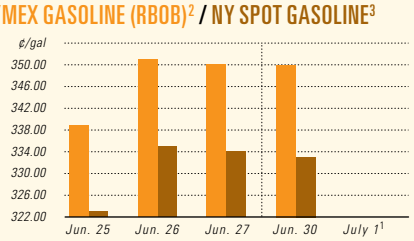
IPE GAS OIL / NYMEX HEATING OIL



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]Non-oxygenated regular unleaded.

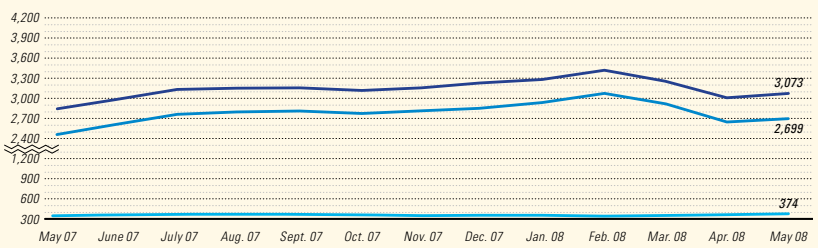
US INDUSTRY SCOREBOARD — 7/7

Latest week 6/20	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,281	9,484	–2.1	9,090	9,191	–1.1
Distillate	4,062	4,108	–1.1	4,171	4,270	–2.3
Jet fuel	1,585	1,645	–3.6	1,557	1,618	–3.8
Residual	612	739	–17.2	649	777	–16.5
Other products	4,693	4,727	–0.7	4,839	4,844	–0.1
TOTAL DEMAND	20,233	20,703	–2.3	20,145	20,707	–2.7
Supply, 1,000 b/d						
Crude production	5,130	5,172	–0.8	5,113	5,190	–1.5
NGL production[2]	2,210	2,367	–6.6	2,275	2,351	–3.2
Crude imports	9,996	10,082	–0.9	9,752	10,022	–2.7
Product imports	3,265	3,632	–10.1	3,240	3,541	–8.5
Other supply[3]	1,388	1,341	3.5	1,413	955	48.0
TOTAL SUPPLY	21,989	22,594	–2.7	21,793	22,059	–1.2
Refining, 1,000 b/d						
Crude runs to stills	14,818	15,278	–3.0	14,818	14,989	–1.1
Input to crude stills	15,030	15,497	–3.0	15,030	15,305	–1.8
% utilization	85.8	88.8	—	85.8	87.7	—

Latest week 6/20	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	301,758	300,955	803	350,891	–49,133	–14.0
Motor gasoline	208,757	208,910	–153	202,582	6,175	3.0
Distillate	119,421	116,598	2,823	120,448	–1,027	–0.9
Jet fuel-kerosine	40,500	39,567	933	40.124	376	0.9
Residual	39,253	38,949	304	35,772	3,481	9.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	19.6	19.6	—	22.9	–14.4	
Motor gasoline	22.5	22.5	—	21.2	6.1	
Distillate	29.4	28.6	2.8	29.0	1.4	
Propane	38.9	36.6	6.3	42.6	–8.7	
Futures prices[5] **6/27**			**Change**		**Change**	**%**
134.73		137.63	134.37	3.26	68.77	68.86	100.1
Natural gas, $/MMbtu		13.05	12.99	0.06	7.42	5.64	76.0

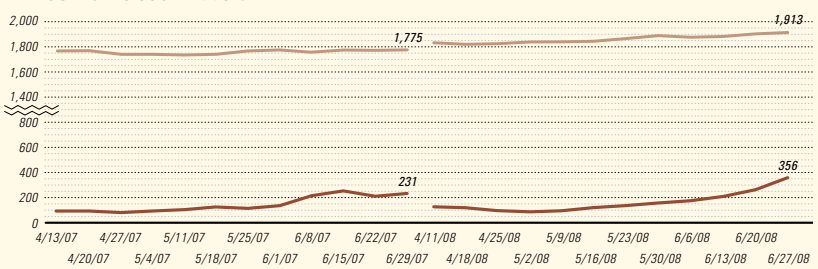
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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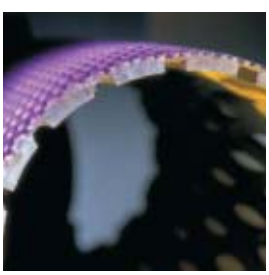

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ervoir in which Tullow found over 5 m of net oil pay of moveable 30-32° API and dry gas in 9 m of net pay spreading through separate sands. The Victoria Nile Delta play, in a new fairway along the axis of the Lake Albert Rift basin, is significant because it upgrades several other prospects to be drilled later.

Tullow will not test the well, as it wants to assess the results of its other wells after it finishes regional drilling. Ngege-1 reached a TD of 640 m and was drilled some 3 km from the crest of the structure.

Tullow said seismic interpretation indicates further significant potential updip. Logging has been successfully completed and the well suspended as a potential future producer.

NOC signs E&P deals with Oxy, OMV

Libya's National Oil Co. has signed exploration and production agreements with Occidental Petroleum Corp. and OMV AG to upgrade their existing petroleum deals (OGJ, Feb. 7, 2005, p. 35).

NOC said the companies would train Libyans and carry out enhanced oil recovery projects.

Oxy's contract covers fields with 2.5 billion bbl of high-quality oil reserves. Libya's largest land holder, Oxy owns a net working interest in nine exploration blocks in Libya covering 130,000 sq km (OGJ, Jan. 23, 2006, p. 31). It will carry out major field redevelopment and exploration programs in the prolific Sirte basin, where it operates Blocks 106 and 124.

Oxy will spend $5 billion over the next 5 years to triple its gross production to 300,000 b/d.

Norway launches 20th licensing round

Norway has invited operators to bid for 79 blocks or parts of blocks under its 20th licensing round that covers the Norwegian and Barents seas. Deadline for applications is Nov. 7.

The petroleum and energy ministry said the licensing round was important to maintain production on the Norwegian Continental Shelf and that new discoveries could help with employment and industrial development on the northern coast.

However, environmental standards and fishery concerns have been tightened in some areas following public consultation.

"The government wants to await the assessments in the upcoming management plan for the Norwegian Sea before starting new petroleum activities outside the More coastline," the ministry said, adding, "Further petroleum activities and conditions in this area will be assessed in the management plan."

The plan will assess the environmental impact of oil and gas activities in the Norwegian and Barents seas and its future development.

BLM posts final EIS for Pinedale Anticline area

The final supplemental environmental impact statement for the Pinedale Anticline Project Area (PAPA) in Wyoming is available, the US Bureau of Land Management said on June 26.

The FSEIS is part of a US Department of the Interior analysis of a proposal by Questar Market Resources Co., Shell Exploration & Production Co., and Ultra Petroleum Inc. The three producers have proposed conducting year-round drilling and completions within the PAPA, BLM said.

BLM added that the FSEIS is not a decision document, but is designed to inform the public and interested agencies of environmental and socioeconomic impacts that could result from the project and to evaluate alternatives.

Additional information acquired from public comments and from internal reviews could result in the selection of an alternatives or group of alternatives to provide the best operating practices, impact mitigation and management practices to reduce environmental harm, BLM said.

UK's Moth a dual oil, gas-condensate find

Although not quantified, the Moth exploration well in UK Central North Sea Block 32/21 is thought to be a large discovery, said the UK subsidiary of Oilexco Inc., Calgary.

The 23/21-6z Moth discovery well went to TD 14,616 ft and cut 605 ft of hydrocarbon-bearing sands in Middle Jurassic Pentland and 219 ft in Upper Jurassic Fulmar, Oilexco said. The company earned a 50% working interest at Moth, where its partners are BG Group, Hess Corp., and BP PLC.

A packer failure prevented flow measurement on a drillstem test of Pentland perforations at 13,276-730 ft in 439 ft of oil and gas bearing reservoir sands. Further tests are likely in a future appraisal well.

The primary target Fulmar sands at 12,982 ft are to be perforated later in July at 12,980-13,030 ft for tests in 118 ft of gas-condensate bearing reservoir sands.

Appraisal wells will likely use higher-capacity test equipment, Oilexco said. Moth is just south of Lomond gas field. ✦

Drilling & Production — *Quick Takes*

Cabinda Gulf installs Angola gas platform

Chevron Corp. subsidiary Cabinda Gulf Oil Co. Ltd. has successfully installed the Takula gas processing platform on Block 0 off Angola. Commissioning and start up is expected to happen during the third quarter.

AMEC Paragon was the engineering contractor for the project.

The platform is in 57 m of water with the capacity to process 100 MMscfd of sour gas for injection and delivery to the new onshore Cabinda gas plant. It is bridge-linked to an existing platform and is a single-train facility designed as a 5,000-tonne, single-lift modular deck.

The platform is key to Angola's determination to reduce onshore and offshore gas-flaring. As engineering contractor to Cabinda, AMEC Paragon provided front-end engineering and design services and offered detailed engineering and procurement assistance to Samsung Heavy Industries for the platform, which was built at the Samsung Geoje shipyard in South Korea.

Callon awards contract for Entrada field

Callon Petroleum Co. has let a lump-sum installation contract to Technip, Paris, for development of Entrada oil field in the Gulf of Mexico.

Technip is to install two 6½-mile steel flowlines that will tie-back two subsea wells at a depth of 4,475 ft. In addition, the French group will be responsible for installation of pipeline terminations and inline structures, as well as steel catenary risers that will be connected to the Magnolia offshore platform in 4,675 ft of water.

Detailed engineering and project management will be performed at Technip's operating center in Houston, while welding of the flowlines and risers will take place at Technip's spoolbase in Mobile, Ala. Technip said offshore installation is scheduled for the third quarter using the firm's Deep Blue deepwater pipelay vessel.

Oxy to acquire interest in Joslyn oil sands project

Occidental Petroleum Corp. signed an agreement with Enerplus Resources Fund to purchase a 15% interest in the Joslyn oil sands project in northeastern Alberta for $500 million (Can.).

Joslyn, operated by France's Total SA, holds more than 8 billion bbl of bitumen in place. While still in the early stage of development, Joslyn currently has more than 1,800 delineation wells drilled and is being developed by steam assisted gravity drainage (in process) and surface mining. Oxy plans to spend $2 billion to develop the reserves, the company said.

Enerplus acquired a 16% interest in Joslyn in 2002 and subsequently sold a 1% interest to Laricina Energy Ltd. in early 2006 in exchange for common stock in that company. Enerplus will have invested $115 million in its 15% interest in Joslyn.

Dong Energy lets Nini East platform contract

Dong Energy let a turnkey contract to Bladt Industries AS to construct and install an unmanned satellite production platform for its Nini East oil field in the North Sea. The site lies 7 km northeast of the existing Nini platform. Bladt said its contract contains an option for future work in the area. Design has begun, and materials specification is under way. Production is scheduled to start by yearend 2009. Nini East holds an estimated 17 million bbl of oil.

Bladt Industries will work with Saipem UK to design, produce, and install both the jackets and topsides and develop a pipeline to connect Dong's Nini and Cecilie fields to the Siri platform where oil will be treated and shipped. Total platform weight will reach about 3,500 tons. Fabrication should take 15 months, after which it will be towed, installed, and commissioned.

Total investment, including a pipeline between Nini and Nini East, is 2.1 billion kroner.

Petrobras, Mitsui sign ultradeepwater contract

Transocean Inc.'s subsidiaries reached an agreement with subsidiaries of Petrobras and Mitsui to acquire a newbuild ultradeepwater drillship under a capital lease contract.

The currently unnamed newbuild is under construction at Samsung Heavy Industries Co. Ltd. yard in Geoje, South Korea.

Costs to be incurred by Petrobras and Mitsui for the drillship's construction are estimated at $750 million.

The rig will feature Transocean's patented dual-activity drilling technology, allowing for parallel drilling operations in deepwater well construction.

Transocean said the rig will have a variable deckload of more than 20,000 tonnes and the capability of development and exploration drilling in greater than 10,000 ft of water, upgradeable to 12,500 ft of water. With additional equipment, it can drill to 37,500 ft total depth.

In conjunction with the 20-year capital lease contract, the companies signed a 10-year drilling contract covering worldwide operations, with an option to extend the drilling contract by 10 additional years. ✦

Processing — *Quick Takes*

Construction begins on Marathon Detroit refinery

Marathon Oil Corp. has begun construction of the $1.9 billion heavy oil upgrading project at its Detroit refinery following issuance of an air quality permit by the Michigan Department of Environmental Quality.

The project will include an additional 80,000 b/d of heavy oil capacity and increase the total refining capacity to 115,000 b/d from 102,000 b/d. The increased capacity will supply more than 400,000 gpd of additional transportation fuels to the marketplace. The project is expected to be completed in late 2010.

Fluor Corp. will provide integrated engineering, procurement, and construction services.

Construction on an associated 29-mile pipeline in Monroe and Wayne counties, Mich., is expected to begin in second-quarter 2009 and complete in 2010.

Aramco, Total form Jubail Refining & Petrochemical

Saudi Aramco and Total SA agreed to create the Jubail Refining and Petrochemical Co. during third-quarter 2008 to develop a world-class refinery in Jubail, Saudi Arabia.

The parties signed agreements June 22 pertaining to a 400,000 b/d refinery scheduled to start operations by yearend 2012. It will convert Arabian Heavy crude to high-quality refined products, complying with the most stringent global product specifications.

"As a full-conversion refinery, Jubail will maximize the production of diesel and jet fuels. In addition, the project will produce 700,000 tonnes/year of paraxylene, 140,000 tpy of benzene and 200,000 tpy of polymer-grade propylene," the companies said in a joint statement.

Aramco will have an initial 62.5% stake in the company, with Total taking the remaining 37.5%. Subject to regulatory approvals, the parties plan to offer 25% of the company to the Saudi public while the two founding shareholders each intend to retain a 37.5%. Both will share marketing of the refinery's products.

Lukoil, ERG form refinery joint venture

OAO Lukoil reported it will pay €1.3 billion to acquire a 49% stake in a new joint venture with Italian refiner ERG SPA. The JV will jointly operate ERG's Isab refining complex at Priolo, Sicily.

ERG will have a 51% share in the JV and Lukoil may be able to increase its stake in the future under the agreement. Both parties require approval from the European Commission and other antitrust bodies.

The complex 320,000 b/d Isab refinery is on the coast and will meet growing middle distillate demand in Europe, mainly kerosine and diesel fuel.

According to their equity stake, ERG and Lukoil will source its own share of oil to refine and market the products. "The Isab refinery has the flexibility to process crudes such as Urals, and Lukoil intends to fully integrate its share of the refinery into its supply chain," Lukoil said.

Lukoil Pres. Vagit Alekperov said the company's refining capacity would increase by 13% and its overseas refining capacity by 60%. "The refinery's advantageous location and an opportunity to process Russian crude make this project very attractive." ✦

Transportation — *Quick Takes*

Five planned LNG terminals in Italy move forward

Italy's privately-held Anonima Petroli Italiana SPA, Rome, applied for approval from the country's Environment Ministry for an offshore regasification terminal with an capacity of about 4 billion cu m/year.

The facility will be located in the Adriatic Sea in front of Anonima Petroli's Falconara refinery. After converting the LNG, the company will inject the gas into Snam Rete Gas SPA's grid. Construction will take just over 5 months.

The news coincided with reports that Gas Natural could win environmental clearance for an 8 billion cu m regasification terminal it wants to develop at Trieste in northern Italy. An official at the environment ministry confirmed that Gas Natural's LNG facility had received positive opinions from a series of subcommittees at the ministry, and it said the project could be approved or a series of observations on the plans could be made.

In June, Iride SPA and CIR SPA's unit Sorgenia SPA said their planned 12 billion cu m regasification terminal at Gioia Tauro, which won environmental approval in April, has been granted access to European Union funding. The Gioia Tauro terminal is due to go online in 2013.

In early May, Royal Dutch Shell and Italy's ERG received local authorization to build their planned joint Ionio LNG import terminal in Sicily. The partners hope to begin construction of the import terminal in 2010 and to have it operational by 2013, according to ERG's power and gas division head Raffaele Tognacca.

Later in May, following a feasibility study completed early this year on its Triton LNG project 30 km off Italy's Marches region in the Adriatic Sea, Gaz de France signed a joint development agreement with Oslo-based Hoegh LNG for the design, construction, and operation of a floating storage and regasification unit vessel (OGJ Online, May 30, 2008).

Maryland LNG project wins CZMA appeal

US Commerce Secretary Carlos Gutierrez overturned one state's objection to a proposed LNG project but upheld another as the US Department of Commerce issued two federal consistency appeals decisions on June 26.

The secretary ruled against Maryland's objection to AES Sparrows Point LLC and Mid-Atlantic Express LLC's proposal to build an LNG facility east of the Port of Baltimore on Chesapeake Bay. However he upheld an objection by Massachusetts to Weaver's Cove Energy LLC and Mill River Pipeline LLC's proposal to build an LNG terminal and pipeline near Fall River.

Sponsors of each project had appealed to a rule after the state had determined that the project was not consistent with its plan under the Coastal Zone Management Act. Under CZMA, federal agencies may not issue permits for a project unless the Commerce secretary overrides the state's consistency objection on appeal.

In a decision announced by the National Oceanic and Atmospheric Administration's Office of General Council for Ocean Services, Gutierrez overrode Maryland's objection after determining that the national interest, which would be served by the Sparrows Point project, outweighs its limited adverse coastal effects.

The proposed terminal and associated pipeline would help meet regional energy demand by providing enough natural gas capacity to heat about 3.5 million homes daily or to generate enough electricity each day for about 7.5 million homes, the decision indicated. The impact of dredging on fish and aquatic vegetation would not be significant, Gutierrez said.

The decision means sponsors of the Sparrows Point project can continue to pursue federal permits and licenses, but will still be required to comply with all state and local permitting regulations and complete all required environmental reviews.

A timetable at the project's web site anticipates that the Federal Energy Regulatory Commission will complete a final environmental impact statement by Aug. 15 and issue a certificate by Nov. 20.

In the Massachusetts decision, Gutierrez upheld the state's objection because it determined that adverse coastal effects, particularly navigational concerns associated with tankers traveling up the Taunton River to deliver LNG to the terminal outweighed the project's national interest.

LNG construction approved for the Netherlands

Dutch Economy Minister Maria van der Hoeven approved construction of the Netherlands' first LNG import terminal in Rotterdam.

The €800 million Gate terminal, a project of Neder Nederlandse Gasunie NV and Royal Vopak, will consist of three storage tanks with a capacity of 180,000 cu m each and one jetty. The terminal will have an initial throughput capacity of 9 billion cu m (bcm)/year, which can be increased to 16 bcm/year in the near future.

A consortium comprised of Techint Group, Sener Ingenieria y Sistemas SA, Entrepose Contracting, and Vinci Construction PLC will build the terminal, which will come online in second half 2011, at a cost of €800 million. Dutch port operator Havenbedrijf Rotterdam NV will invest €60 million in basic infrastructure as the project will significantly strengthen its position as an energy port. ✦

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Letters

Global warming response

It is well known that the hydrocarbon industry, by its very nature, is responsible for a large share of the production of products which go on to become greenhouse gases. Some elements of the industry have historically been very conservative in their outlook towards environmental matters, not least in the historical heartland of the industry, the US. Hence telling the hydrocarbon industry that its products are the cause of global warming has been rather like telling a young mother that her baby is ugly. It is undoubtedly difficult to argue the effects of global warming, which has proven to confront the comfort zone of some people in those industries–never an easy task. This is often because the data are not clear-cut but rest on the basis of probabilities but which, in the opinion of experts, indicate that the cause and effects are pretty certain. Too many people make judgments on the micro level (e.g., the weather today), whilst not having access to the macro information on world climate changes (e.g., melting glaciers).

Global warming is a global problem, which requires a global solution, and unless we get the energy industries on board, including those in the US, any attempts to solve this problem are doomed. It is disappointing that, despite substantial and substantiated evidence, we continue to see letters such as that from DeForrest Smouse, which counters the learned (and mostly independent, despite what he wants to think) bodies of opinion (OGJ, June 2, 2008, p. 12). When we outside America hear Americans like Mr. Smouse say, "We need a concerted effort to stop the scare tactics of those whose major purpose is in opposition to the economic stability of the advanced nations of the world," we are saddened.

America, please wake up. Please remove your prejudices. Please read the huge information available. A good place to start would be with the final Intergovernmental Panel on Climate Change report, found at http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf. Then please join with the rest of the world to solve this problem. We are waiting for you.

Jeff Temple
Petrokazakhstan Oil Products
Shymkent Refinery,
Kazakhstan

Calendar

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

OIL&GAS JOURNAL online

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.

2008

JULY

International Offshore & Polar Engineering Conference, Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Annual Rocky Mountain Natural Gas Strategy Conference & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

AAPG/SPE/SEG Hedberg Conference, Casper, Wyo. (918) 560-2630, (918) 560-2678 (fax), e-mail: debbi@aapg.org, website: www.aapg.org. 14-18.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

SPE Nigeria Annul International Conference & Exhibition, Abuja, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

International Petroleum Petrochemical Natural Gas Technology Equipment Exhibition, Shanghai, +86 21 55611008, +86 21 65282319 (fax), website: postmaster@aiexpo.com.cn, website: www.sippe.org.cn. 20-22.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

DeepWater India Summit, New Delhi, +31 (0)26 3653 444, +31 (0)26 3653 446 (fax), e-mail: workshops@energywise.nl, website: www.energywise.nl. 26-27.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

Annual India Oil & Gas Review Symposium & International Exhibition, Mumbai, (0091-22) 40504900, ext. 225, (0091-22) 26367676 (fax), e-mail: oilasia@vsnl.com, website: www.oilasia.com. 1-2.

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

Rice Global Engineering & Construction Forum, Houston, (713) 552-1236, ext. 3, (713) 572-3089 (fax), website: www.forum.rice.edu. 9.

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

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

API Fall Refining & Equipment Standards Meeting, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15-17.

Rio Oil & Gas Conference & Expo, Rio de Janeiro, 55 21 2112 9078, 55 21 2220 1596 (fax), e-mail: riooil2008@ibp.org.br, website: www.riooilegas.com.br. 15-18.

API/NPRA Fall Operating Practices Symposium, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 16.

GEO India South Asia's Geosciences Conference & Exhibition, New Delhi, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: geo@oesallworld.com, website: www.geo-india.com. 17-19.

Calendar

SPE Annual Technical Conference & Exhibition, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 21-24.

ERTC Petrochemical Conference, Cannes, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 29- Oct. 1.

International Pipeline Exposition, Calgary, Alta., 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. Sept. 30-Oct. 2.

Unconventional Gas International Conference & Exhibition, Ft.Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 30-Oct. 2.

OCTOBER

✦GPA North Texas/NGS East Texas Red River Conference, Tyler, Tex., (713) 222-0852, (713) 222-0858 (fax), e-mail: tom.rommel@accessed.com, website: www.gasprocessors.com. 1-2.

NPRA Q&A Forum, Orlando, Fla., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 5-8.

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessor.com. 7.

KIOGE Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-10.

IADC Drilling West Africa Conference & Exhibition, Lisbon, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 8-9.

International Gas Union Research Conference, Paris, +31 50 521 30 78, +31 50 521 19 46 (fax), e-mail: igrc2008@gasunie.nl, website: www.igrc2008.com. 8-10.

ERTC Lubes and Additives Conference, Berlin, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

Middle East Plant Maintenance Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: d.michalski@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 13-15.

API Fall Petroleum Measurement Standards Meeting, Long Beach, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 13-17.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 13-17.

Central and Eastern European Refining & Petrochemicals Roundtable, Warsaw, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-16.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 14-16.

Oil & Gas Transportation in the CIS & Caspian Region Conference, Moscow, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: j.golodnikova@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/cispipes10register.html. 14-16.

PIRA New York Annual Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

Petchem Arabia Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.verma@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 20-22.

SPE Asia Pacific Oil & Gas Conference & Exhibition, Perth, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

SPE International Thermal Operations & Heavy Oil Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 21-23.

AAPG International Conference & Exhibition, Cape Town, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 26-29.

Biofuels Conference, Berlin, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 28-30.

SPE Russian Oil & Gas Technical Conference & Exhibition, Moscow, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-30.

Arab Oil & Gas Show, Dubai, +971 4 3355001, +971 4 3355141 (fax), e-mail: info@icedxb.com, website: www.ogsonline.com. 28-30.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 29-30.

NOVEMBER

ASME International Mechanical Congress & Exposition, Boston, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 2-6.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, website: www.adipec.com. 3-6.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 4-6.

North African Oil and Gas Summit, Vienna, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: c.brown@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/nas3register.html. 4-6.

Mangystau International Oil & Gas Exhibition, Aktau, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 5-7.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

Calendar

IADC Annual Meeting, Paradise Valley, Ariz., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 6-7.

SEG International Exposition and Annual Meeting, Las Vegas, (918) 497-5542, (918) 497-5558 (fax), e-mail: register@seg.org, website: www.seg.org. 9-14.

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

ERTC Annual Meeting, Vienna, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 17-19.

Annual Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 18-20.

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 24-25.

Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.com, website: www.theeagc.com. 25-26.

DECEMBER

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 2-3.

Annual Refining & Petrochemicals in Russia and the CIS Countries Roundtable, Prague, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 2-4.

Downstream Asia Refining & Petrochemicals Conference, Singapore, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/dalregister.html. 3-4.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition, Perth, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8-9.

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

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

XSPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

XSPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.piipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

FEBRUARY

SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 2-4.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition (DOT), New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 3-5.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

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GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

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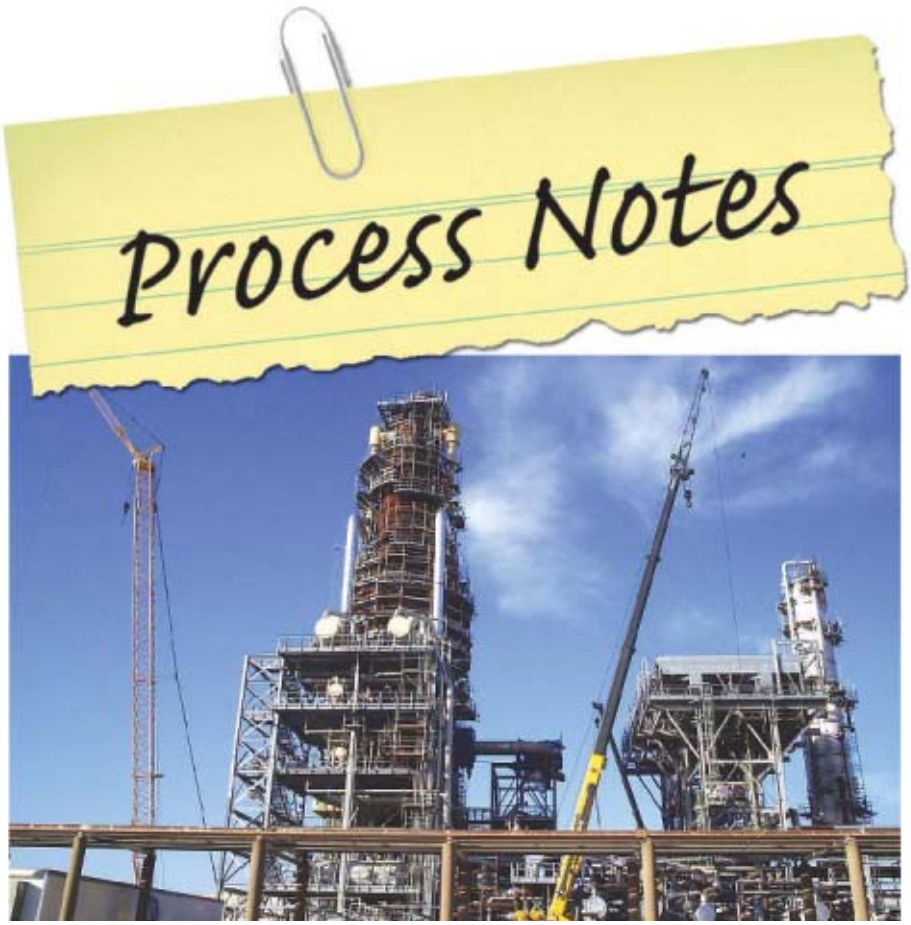

The Myth of the 1000°F Vacuum Unit Cutpoint

Canadian Synbit and Dilbit crudes will come to make-up a substantial fraction of feedstocks to North American refineries. Today, however, for the most part refiners both north and south of the 40° parallel seem to be unaware of the extreme challenges this change will present. To run an oil sands crude in a vacuum unit designed for conventional heavy feedstocks and to expect a 1000°F cutpoint for a 5-6 year run is like believing in the Tooth Fairy. Bitumen based crudes are ultra-heavy, fouling, hard to desalt, corrosive, thermally unstable and tough to vaporize in the vacuum column flash zone even at elevated temperatures. Can any crude oils be nastier to cope with?

First and foremost, heater outlet temperature can be no higher than 725°F and possibly lower to avoid extremely high cracked gas rates and rapid coke laydown. Even at these reduced temperatures the heater tubes must be double-fired, coil steam rates high, coil layout correct, oil mass velocity high and heater outlet pressure selected properly. But won't lower heater outlet temperature increase the coker charge rate by 25% or more? Yes …with current unrealistic vacuum column design! The proper design is one which can provide minimum coker charge with design features that incorporate efficient residue stripping and low column operating pressure.

If you design your vacuum unit correctly you can indeed expect to achieve a 975°F VGO cutpoint and a 5-6 year run length. But it won't come from conventional cheap unit designs. If the wrong designs are used it could mean replacing the heater, having to add residue stripping and new ejector systems. The revamp can cost 40% of a new unit. The choice is yours. Pay now or pay through the nose later.

A last word: Because process and equipment design is critical when processing oils sands crudes, know-how and actual experience designing units to process these feedstocks can make the difference between success or possibly disastrous reliability and yields.

For a more thorough discussion of cutpoint ask for Technical Papers 236 and 237.

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Journally Speaking

Formula for energy security

Judy R. Clark
Senior Associate Editor

The National Petroleum Council (NPC) 10 months ago presented to the US Department of Energy its comprehensive study, "Hard Truths," which addressed maintaining US and world energy security without jeopardizing economic growth (OGJ, Aug. 6, 2007, p. 26).

NPC's study evaluated the future of energy to 2030 and analyzed technology trends, opportunities, and policy options. Its findings included:

- Total global energy demand will grow by 50-60% by 2030.
- Coal, oil, and natural gas will remain indispensable through 2030.
- Expansion of all economic, environmentally responsible energy sources will be needed, including coal, nuclear, unconventional oil and gas, and biomass and other renewable energy forms.
- Action must be initiated immediately and sustained over the long term.
- Risks include political hurdles, infrastructure requirements, and the need for a competent, trained workforce to replace retiring scientists, engineers, and other energy personnel.

"The concept of 'energy independence' is not realistic in the foreseeable future," NPC concluded. However, it said moderating demand, expanding and diversifying domestic energy supplies, and strengthening global energy trade and investment could enhance US energy security.

"There can be no US energy security without global energy security," it cautioned.

Five essential goals

NPC specified steps to achieve five core goals:

1. Moderate demand, increasing efficiency in transportation, industrial, residential, and commercial use.

- As much as 3-5 million b/d of oil could be saved in the US by 2030 by maximum improvement of car and light truck fuel economy standards, adjusting light truck standards, and reducing vehicle weight, horsepower, and amenities.
- As much as 7-9 quadrillion btu/year could be saved by states' implementing and enforcing aggressive energy-efficient building codes, establishing appliance standards for new products, and updating federal appliance standards regularly.
- To save a potential 4-7 quadrillion btu/year, DOE should promote and conduct research and development (R&D) of industrial energy efficiency technologies and best practices and have the government permanently extend the R&D tax credit to spur private R&D investment.

2. Increase domestic supply.

- Promote enhanced oil recovery from existing reservoirs.
- Conduct national-regional, basin-oriented resource and market assessments, and use technology advancements for responsible development of high-potential areas now restricted by access limitations (potential: 40 billion bbl of oil and 250 tcf of gas).
- Accelerate oil shale and oil sands R&D and leasing and unconventional gas leasing and development (10 bcfd).
- Research second-generation biofuels crops that have lower input requirements or that are suited to more marginal lands (4 million b/d). Promote agricultural policies that enhance global production of both food crops and biomass for fuel.
- Expand nuclear energy-power industry and fulfill federal commitments on nuclear waste management.

3. Improve energy technology and methodology by enhancing science and engineering capabilities and creating long-term R&D opportunities in supply-demand systems.

- To increase the number of trained energy professionals, provide scholarships for engineering and technical students, fund research at universities, and support technical schools.
- Modify the US tax code and retirement plan regulations to allow part-time work after retirement without penalty.

4. Address carbon capture and sequestration (CCS). Develop a legal and regulatory framework for reducing CO_2 emissions, and encourage development of enabling technology. Provide a global framework for carbon management, including a transparent, predictable, economy-wide, market-based cost for CO_2 emissions. Any cost imposed should consider the actions of other countries and their effects on US competitiveness.

- Provide access to federal lands for storage.
- Enable the long-term environmental viability of coal for power and fuel. Enable full-scale CCS and clean coal technology demonstration, organize efforts between the power and oil-gas industries, and undertake a national CO_2 sequestration capacity assessment, encouraging global application. Focus on opportunities for US-China cooperation.
- Select the best policy avenue for limiting CO_2 emissions: direct regulation, cap-and-trade, or carbon taxes and fees.

5. Integrate energy policy into trade, economic, environmental, security, and foreign policies. Strengthen global energy trade and investment. Broaden dialogue with producing and consuming nations, including China, India, Canada, Mexico, Russia, and Saudi Arabia. Assist and encourage global adoption of energy-efficiency technologies through technology transfer programs and lend-lease arrangements, and promote a global energy marketplace through G8, World Trade Organization, International Energy Agency, and Asia-Pacific Economic Cooperation. ✦

Oil sands: the short view

Canadians know energy short-sightedness when they see it. This quality distinguishes them from their neighbors to the south.

Election-year goofiness targeting the oil sands of Alberta has nearly escaped notice in the US. But it's creating an uproar in Canada.

Well it should. The oil sands represent a world-class resource. Their development dominates—some say overheats—the Albertan economy and accounts for much of the economic growth of all of Canada. Oil sands and heavy oil have the potential to generate wealth for many decades. And a market needing oil lies just across the border.

Fickle market

But that market is fickle. A few politicians have discovered that the production of oil sands and heavy oil emits more greenhouse gases than that of most conventional oil. They see this as a reason to shun the development and use of unconventional hydrocarbons. Their choosiness plays into the hands of extremists who want humanity to quit burning hydrocarbons of any type.

Congress initially raised alarm about the environmental drawbacks of oil sands with a section in last year's Energy Independence and Security Act that seems to prohibit federal agencies from buying fuels derived from unconventional crude. Lawmakers have said they didn't intend to impose such a ban. An effort to clarify the measure is under way.

The idea, however, won't die. Last month the US Conference of Mayors adopted a resolution modeled on the federal initiative. It called for bans on purchases for use in city vehicles of any fuel with life-cycle emissions of greenhouse gases deemed excessive. Democratic presidential candidate Barack Obama, who spoke at the meeting, later took an apparent jab at oil sands with a comment about "dirty, dwindling, and dangerously expensive" oil.

These developments have received little attention in the US. In Canada, however, they're big news. A June 26 article in the Calgary Herald, for example, said grumbles about oil sands in the US have stimulated efforts to develop markets elsewhere.

Political revulsion toward oil sands serves no legitimate interest and highlights the confusion rampant in US discussions of energy. A country with an appetite for oil as strong as that of the US—an appetite that will remain hearty no matter what policies the nation adopts—can't afford to spurn supply from any source. It also can't afford to appear hypocritical in international affairs, as the US so often does on energy.

The country perpetually regrets its dependence on oil from far-off exporters thought to be hostile, for example, yet now resists supply from a friendly and nearby neighbor. It frets about the reliability of supply from foreign producers yet gives no apparent thought to its own reliability as a consumer. For persuasive economic reasons, the US so far has refused to adopt limits on emissions of greenhouse gases. But it doesn't hesitate to act on climate change when the target is an energy resource central to the economy of another country—a country that happens to be a premier ally.

What's more, resistance to the use of products derived from bitumen and heavy oil conflicts with environmental values. Contrary to the unrealistic wishes driving energy politics, the US and the world will continue to use oil in large amounts for many decades. The substance has advantages of scale and form against which nonhydrocarbon energy sources can't easily compete. Energy policy should aim not to eradicate the use of oil and other fossil energy but rather to manage the environmental consequences of that use while helping other energy forms gain economic traction as supply supplements.

A laboratory

The oil sands of Alberta present nearly every environmental and social problem associated with oil development and consumption. They also offer the immediate economic compulsion to find solutions. Alberta thus is a commercial-scale laboratory from which energy companies, governments, and environmental groups can learn much about managing the disadvantages of fossil energy in order to responsibly exploit the many advantages.

To foreclose such important work, as the US initiatives obviously seek to do, indeed would be short-sighted. It also would be irresponsible. ✦


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'Silent disruption' limiting oil supply

Lucian Pugliaresi
Ben Montalbano
Energy Policy Research Foundation Inc.
Washington, DC

Recent increases in the price of oil result largely from a collision of demand growth with what might be called a "silent disruption" to worldwide supply.

Like past constrictions to the delivery of crude oil and oil products, the current phenomenon has raised prices as much by lowering expectations for future supply as by immediately removing physical volumes from the market. Unlike past disruptions, this one lowers expectations not by way of a single event, such as a war or natural disaster, but rather through a series of mostly geopolitical developments that together impede investment.

The combined effects of those developments, important among which is a surge in resource nationalism, have lowered expectations for global oil supply during 2005-10 by 2.5-4.5 million b/d (see table).

The crude price

In 2008, the cost of crude oil—combined with federal and state taxes—has accounted for 90-93% of the price of gasoline at the pump in the US (based on West Texas Intermediate prices plus 50¢/gal of federal, state, and sales taxes).

So why are crude prices so high?

Over the last 10 years, the world oil market has clearly experienced an unprecedented number of new and sustained impediments to upstream development, including unilateral contract renegotiation, nationalization, lack of investment by national oil companies, restrictive access to resources, and war and civil strife.

Many of these factors, along with technical challenges in bringing new oil fields online, have also reduced excess production capacity among members of the Organization of Petroleum Exporting Countries. At the same time, global oil demand has grown robustly (see figure).

When the events highlighted in the figure occur, not only does the world oil market lose existing production, but expectations on the availability of future supplies are revised downward.

A recent or perhaps recurring trend is resource nationalism, wherein host nations change the terms of their contracts with international oil companies (IOCs) that are developing indigenous oil and gas resources. Encouraged by the swift escalation of oil prices in recent years, this trend is now spreading rapidly. Venezuela's 2007 nationalization plan led to a significant decline in investments and even the expulsion and banning of ExxonMobil from the country. Foreign direct investment in 2007 declined by about 50% compared with the yearly average during 2003-06. Rising oil prices have emboldened governments to take a greater share of the revenue of projects, agreements for which were negotiated when oil prices were substantially lower. Production at Kazakhstan's 13 billion bbl Kashagan oil field was delayed for several years as the operators faced a series of technical obstacles. The delay in bringing the field into production was one of several reasons the Kazakh government gave for renegotiating the 2005 contract.

Many explanations for these actions are advanced, including that existing production contract terms do not permit a fair distribution of the good fortune of rising prices. Even in Canada and the US, investors are not immune from attempts by their respective legislative bodies to change previously agreed-upon contract terms.

Operating companies, with some notable exceptions, have had little choice but to accept these new terms to protect residual value in their projects as existing legal alternatives are either too cumbersome or present further risks to remaining operations in the host county.

The longer-term consequences of these unilateral actions are much more than a redistribution of revenue. These actions are likely to result in further

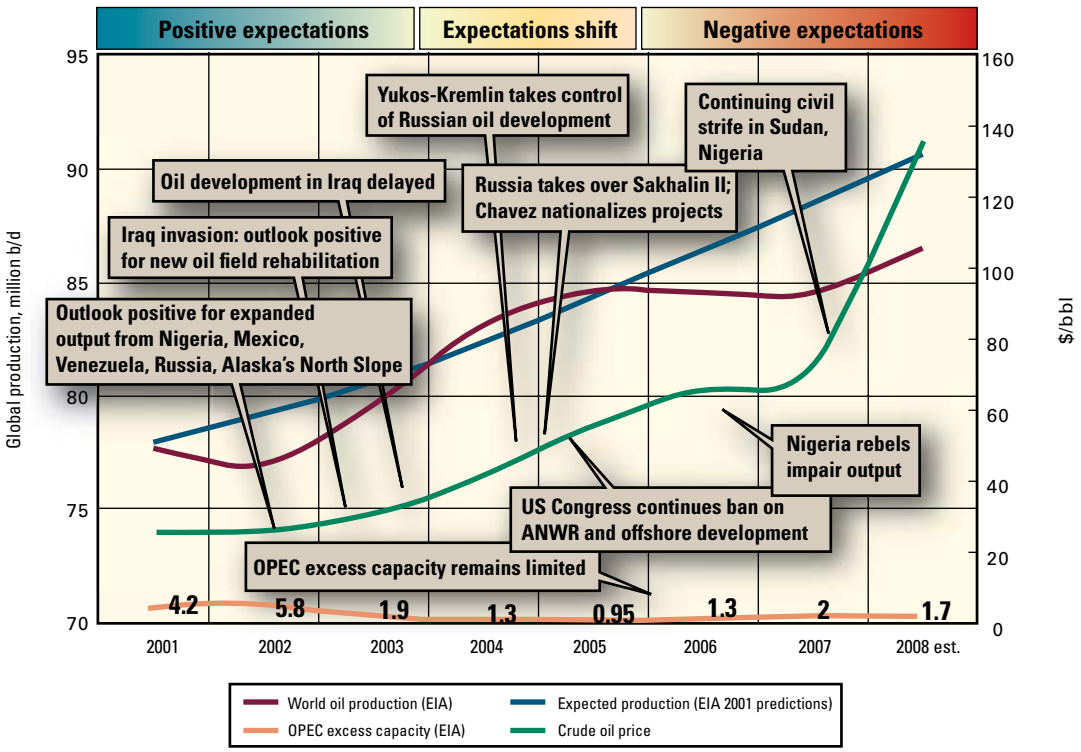
This article is based on testimony presented to the Task Force on Competition Policy and Antitrust of the US House of Representatives Committee on Judiciary hearing on retail gasoline prices May 7, 2008.

EVENTS THAT LED OIL MARKETS FROM POSITIVE TO NEGATIVE EXPECTATIONS

Country	**Era of positive expectations** *Outlook in general (but not always) is positive (1998-2004)*	**Era of negative expectations** *Outlook in general (but not always) is negative (after 2004)*	**Lost production*** *Oil market production losses between the two eras, both from base level output and expected new output*
Iraq	Produced 2.4 million b/d 1999-2002. The US invasion in 2003 offered promise of rapid investment in Iraqi oil sector as economic sanctions were removed.	Turmoil in Iraq drops output to 1.8 million b/d in 2003-06. Investment in field rehabilitation and new fields postponed.	Lost production between eras, 600,000 b/d, plus unrealized additional output from postponed investment and inability to perform field rehabilitation.
Nigeria	Production rose to 2.4 million b/d from 2.1 million b/d during 2000-05, with expectations of achieving up to 4 million b/d by 2010 commonly accepted prior to 2005.	Civil strife and attacks on oil infrastructure has hurt production and investment. Oil production declined in both 2006 and 2007 (2.11 million b/d) after 2.4 million b/d in 2005.	500,000-700,000 b/d due to shut-in production, political instability, and fighting, plus unrealized additional output from postponed investment.
Venezuela	In 2002 oil production surpassed 3 million b/d, and showed growth potential after several years of relatively consistent production.	A strike at yearend 2002 at PDVSA sent production into a nosedive. As of 2007 the country had recovered to slightly less than two thirds of 2002 peak production. Recent nationalization has hurt investment, furthering Venezuela's production difficulties and growth potential.	About 800,000 b/d decline in output, not restored after 2002-03 strike, plus loss of previously expected output expansion after 2007 nationalizations, due to likely fall-off in investment.
Russia	Russian production skyrocketed during 1999-2005, to 9.51 million b/d from 6.31 million b/d. Privatization of Russia's energy industry brought in western investment and more-efficient production and management methods. Output was projected at 10 million b/d by 2006 and expected to grow to 12 million b/d by 2010.	Renationalization of Russian oil companies, most notably Yukos in 2004, scared off investment and slowed production growth. Russia failed to reach 10 million b/d production as of January 2008 but has seen slight growth over the past few years. Russia's major fields in Western Siberia remain in decline; Eastern Siberia is not yet producing oil.	Near-term loss of output from renationalization 200,000-400,000 b/d. Longer term loss unknown, but could be substantial, and loss in annual output over next 10 years may be as much as 1 million b/d.
Sudan	A peace treaty signed in 2005 to end the country's civil war was expected to allow for development of previously inaccessible fields. The Sudanese government said in 2005 production would reach 600,000 b/d by 2006. Oil reserves were in the billions, rather than the previously known 560 million bbl of proved reserves.	Fighting has continued and rebel groups launched recent attacks against oil facilities in Sudan, mostly run by Chinese companies. Production has yet to reach 600,000 b/d and has fallen about 200,000-250,000 b/d short of expectations over the past few years, but grew to 570,000 in 2007. New production slow to come online as many new fields remain inaccessible due to fighting, and many western countries have launched divestment initiatives.	200,000-250,000 b/d of additional output not realized, investment outlook remains limited, and access to known reserves has declined.
Argentina	During 1991-98 Argentina's crude oil production grew by 80% to 917,000 b/d. After 2 years of slight decline, production picked up again in 2001.	During the 2 years following 2001, production remained constant. In 2004 Argentina nationalized the country's oil industry and created state oil company Ensara. Ensara has been poorly funded by the government.	State company, Ensara controls all oil projects; oil production has been declining since 2004 and dropped below 800,000 b/d in 2007.
Kazakhstan	After the fall of the Soviet Union, Kazakhstan opened its borders to oil and gas exploration. A major discovery was made in the Caspian Sea of an estimated 13 billion bbl. Production from this field, Kashagan, was expected to begin in 2005 with a consortium of foreign oil companies and Kazakhstan's KazMunaiGaz.	The government has implemented several restrictions against foreign oil companies over the past several years as it seeks to strengthen control of its energy resources. It currently is renegotiating the Kashagan deal it made several years ago with the consortium of foreign oil companies.	Most of the Kashagan oil output delay is due to technical problems. Difficult to determine future loss from government-forced renegotiation of contracts, but may result in chill on investment levels for new resources.
US	Opening the Arctic National Wildlife Refuge (ANWR) to development—it has an estimated 10.4 billion bbl of crude reserves—was the major part of President George W. Bush's energy policy when he took office in 2000.	Legislation that would allow drilling in Arctic National Wildlife Refuge (ANWR) has failed to be passed by Congress. Attempts at new offshore exploration have seen similar fates. In August 2007, US courts revoked Shell's right to drill three exploration wells in the Beaufort Sea near ANWR.	Depending on when ANWR leasing would have occurred, loss in domestic production could be substantial, the exact amount is unknowable as the prospect has not been drilled, but it could be as much as 1 million b/d had leasing occurred 10 years ago.
Canada (Alberta)	Canada has the second largest crude oil reserves in the world, 179.2 billion bbl, behind only Saudi Arabia. It is estimated that about 95% of those reserves are located in Alberta's oil sands deposits.	In 2007 the Alberta government introduced new royalty rates, which will increase the government's take by an additional 15%. Alberta has already seen a loss of investment that will hinder future production in the region. In 2007, oil and gas land sales were down over 50%.	Several companies, including Canada Natural Resources, Nexen, and Imperial Oil have announced reduced investment in the area. Loss of output is unknown, but rising royalty rates likely will curtail future output growth.
Bolivia	In 1999-2006 natural gas production, a major part of Bolivia's economy, grew by nearly 400% to 466 bcf.	Nationalization of state energy resources in 2006 by President Evo Morales and the subsequent loss of foreign investment and management caused production growth to diminish. The government announced that it will be unable to meet contractual export requirements to Argentina and Brazil in 2008.	Lost production and exploration due to significant decline in investment. Loss of new production is unknown, but is likely to be substantial over the next 5 years.
Mexico	During 1995-2004 Mexican production increased to 3.85 million b/d from 3.08 million b/d. In September 2004, the EIA predicted production of 4 million b/d in 2005.	Mexico's production has been in decline since 2004. The 4 million b/d predicted for 2005 never materialized. Instead output dropped to 3.78 million b/d. Only 3.53 million b/d were produced in 2007, and 3.39 million b/d are expected to be produced in 2008. Some analysts believe Mexico's oil output has peaked, but the more serious problem is that Pemex, Mexico's state-owned oil monopoly, does not have the funds needed for exploration and development of new fields.	Much of Mexico's lost production comes from lack of funding for Pemex. Pemex's budget is subject to approval by the Mexican Congress. Pemex operates on a very tight budget, large debt service, and no legal authority to bring in outside investors. We estimate lost of Mexican supply to the world market in 2005-10 to be at 500,000 b/d and possibly more.

*Estimated loss of supplies to the world market, 2005-10, would be 2.5-4.5 million b/d. In the end, the estimate of lost production is just that, an imprecise estimate. In many respects, the lost opportunities from these unfortunate events may be more significant as producers lose opportunities to evaluate and extend new technology and gain information that could enhance future exploration in the region in question.
Sources: Energy Information Administration, USGS, Upstream Online, Oil and Gas Journal, Institute for Energy Policy (Moscow), EPRINC

EVENTS LEADING TO NEW EXPECTATIONS



reductions in investment in the exploration and development of petroleum resources, an arena in which there is a growing consensus that the industry is already "effort-constrained."

Russia's attempts at resource nationalism may have come at an inopportune time. Foreign investment has suffered over the past several years as its western fields are in decline. Output has now dropped for 5 months in a row, and strife at TNK-BP has intensified.

Projects that present relatively high technical thresholds, extraordinary project completion risks, and very long lead times to initial production may now be unable to attract adequate capital to go forward.

This trend in unilateral contract changes, combined with growing limitations on access to resource development, and in many cases unrealistic terms for new projects, is all adding to the so-called peak-oil problem, which is now more about constraints above the ground than below. In a kind of perfect storm of bad luck, the resurgence in resource nationalism has been supplemented by civil strife and armed conflicts in several important producing regions in the world.

The world oil market has been subject to considerably more turmoil than that generated by the resurgence in resource nationalism—armed attacks in Nigeria and Sudan are relevant examples of the rebel activity and civil strife that have caused and continue to bring to the world reduced oil market output—and more importantly, expectations that new opportunities to expand production must be postponed.

Role of expectations

Ultimately, prices in the world oil market are set by the fundamentals of supply and demand. However, crude oil prices at any given moment reflect a wide range of considerations that go well beyond immediate conditions in the market.

Important among these considerations are expectations about future conditions and events including world demand, technological advances, availability of skilled workers, accessibility of supplies, replacement cost of new supplies, technical and political risk, war, and terrorism, among others. In many cases, the immediate loss in output from any number of unexpected events has much less effect on the world market than the resulting shift in expectations about the ability to expand output over the next 5-10 years.

Major shifts in the price of crude oil since the early 1970s can be explained in part (perhaps largely) by major shifts in expectations about future output. For example, the important consequence of the 1973-74 Arab oil embargo was the structural shift in the ownership and control of the vast resources of the Persian Gulf region. The embargo, by changing expectations about future production levels from the major Middle East oil producers, brought about a sustained increase in the value of oil.

The second oil price shock, in 1979, can be seen in a similar light, as the Iranian revolution also sent a signal that the region was in for a period of instability and that the prior view that future output from Iran and Iraq would expand substantially was no longer likely. In both cases, prices were affected by changing expectations about future production levels.

The subsequent fall in oil prices in the mid-1980s can be linked to a fun-

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Constraints in worldwide refining capacity

The US currently consumes about 20.5 million b/d of petroleum and produces about 8.5 million b/d, including natural gas liquids and processing gains. Its remaining supply is provided via imports of crude oil and petroleum products plus about 700,000 b/d of ethanol.

However, ethanol is not petroleum, and it presents some unique challenges to the transportation fuels division of the industry. It is relatively more expensive to transport as it has no access to the US products pipeline network, operates at two thirds the btu value of conventional gasoline, and consumes substantial volumes of transportation fuels in the production of its main feedstock, corn.

Rising world demand for transportation fuels, particularly middle distillates, have grown at a much faster rate than additions to refinery capacity. The world refining industry, therefore, is operating at very low levels of excess capacity; furthermore, existing capacity is not well matched to the recent high growth in demand for middle distillates. This creates an environment producing periodic spikes in the price of transportation fuels. For example, US refining capacity is 4 million b/d below effective available capacity (3 million b/d below nameplate capacity). As a result, the US must import diesel fuel and gasoline components—historically 10% of consumption—from foreign refineries.

Middle distillates, including diesel fuel, have been growing at much higher rates than gasoline. Until new worldwide refining capacity is added to improve the output of middle distillates, the world can expect to continue facing a market where gasoline remains heavily discounted to diesel fuel.

Although both gasoline and diesel prices are very high, the price of gasoline has been attenuated by the large volumes of coproduced gasoline components on the world oil market. As European and Asian refining centers attempt to maximize output of middle distillates, they have no choice but to also produce gasoline components which are often sold into the US market.

The decline in the value of the US dollar also has increased the cost of imports, but EPRINC is reluctant to speculate whether there is a direct causal relationship between the two. This is a complex and esoteric issue involving trade flows and monetary policy which is better addressed by analysts other than EPRINC.

damental shift in medium-term expectations about demand (as consuming countries engaged in fuel substitution and conservation) and to Saudi Arabia's becoming no longer willing to restrict output to protect the price structure.

From the 1980s until the 1999 oil price recovery, OPEC was unable to limit (or had collectively been unwilling to agree to a strategy of limiting) sufficient volumes of oil production to obtain price levels that were substantially above long run replacement costs. Part of the problem with OPEC is that it collectively does not and cannot arrive at a consensus on long-term production strategy because of the divergent long-term interests of its membership.

Prices surge

Since mid-2004 the price of oil has risen dramatically as the world oil market also has faced a perfect storm of bad luck. Resource nationalism has run rampant, harming near-term output, and shifting expectations on future production.

World oil prices initially rose to $30/bbl from about $10/bbl. While this was substantially above the levels experienced in the 1990s, it reflected some combination of rising demand and increased difficulty in replacing reserves as producers moved to technically more challenging environments, having produced much of the "easy" oil. The supply outlook was generally positive, with output rising to keep pace with growing global demand.

Expectations about rising investment in oil and gas development in Nigeria, Russia, Sudan, Venezuela, the US, and many other places soon turned into an environment where projects were postponed, access to resources was denied or postponed, or contract terms were changed. Within a few years, an era of positive expectations during 2000-04 evolved into an era of negative expectations, and the bad news keeps on coming.

Superimposed on this supply situation have been rising incomes in China, India, and other parts of the developing world. In these economies, too, demand is rising rapidly for middle distillates, particularly diesel fuel.

The figure and table show the forces that have brought about much of the shift in expectations about production. Note that by early 2005 historic forecasts of production growth by the US Energy Information Administration and others were unrealized. Combined with falling OPEC excess capacity, this shrinking of expectations about future production helped drive crude oil prices upward.

Effects of disruption

The oil market is highly integrated, and a disruption somewhere in the market is a disruption everywhere.

The silent disruption described here results not from a single event but from events at several production centers. This production is missing from the market, and the subsequent higher prices are imposing substantial costs on the US economy and US consumers.

In the period described in the figure

as the "Era of positive expectations," buyers and sellers reasonably expected that oil supplies would grow from major producing regions. These additions to output did not occur, largely because of problems above the ground and not below. The problems in the upstream market have been amplified by constraints in refining capacity (see sidebar).

Oil prices of course could be expected to rise in response to demand growth and the rising costs of new supplies. But current price increases reflect a failure of the world petroleum market to deliver new supplies from fields that could easily do so within the current (or even a lower) price structure.

US policies that have restricted opportunities to expand conventional supplies from Alaska and prospective offshore and onshore provinces in the Lower 48 have contributed to this high-price environment, along with civil strife in Nigeria, delays in new OPEC capacity, and resource nationalism in Venezuela.

Many observers have argued that these higher prices provide benefits in the forms of demand reduction, new conservation initiatives, and acceleration of incentives for moving the US to the fuels of the future. Whether this is a cost-effective approach for the US economy depends on whether current prices are in fact approaching the long-run backstop price: i.e., the price where alternative fuels, conservation, unconventional supplies, etc., are so plentiful that the price of oil can rise only modestly if at all.

Our perspective is that the current price structure is not sustainable. But failure to provide access to conventional fuels may mean the transition to a lower and more-realistic price level may also involve unnecessary economic pain. ✦

The authors

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Barbs fly as House 'Use it or lose it' bill headed to floor

Nick Snow
Washington Editor

US House Democrats and Republicans accused each other of indifference to record gasoline prices as the weeklong Independence Day recess drew closer. Voters are asking why Congress hasn't acted, lawmakers on both sides of the aisle said.

The parties remained far apart on solutions June 25 as Democrats promoted bills they said would benefit consumers more than major oil companies and Republicans demanded legislation that would increase available domestic supplies.

Speaker Nancy Pelosi (D-Calif.) said the House would have an opportunity to do exactly that on June 26 when it debated HR 6251, which is formally designated the Responsible Federal Oil and Gas Act but which is more commonly called the "Use it or lose it" bill (OGJ Online, June 24, 2008).

"There are tens of millions of acres these big oil companies already have where they're not drilling," she told reporters in a briefing that included Majority Leader Steny H. Hoyer (Md.), Majority Whip James E. Clyburn (SC), Democratic Caucus Chairman Rahm Emanuel (D-Ill.) and the caucus's vice-chairman, John B. Larson (Conn.).

"We believe hundreds of millions of barrels of oil and trillions of cubic feet of natural gas are available on already authorized leaseholds," Hoyer said. Voters will not accept excuses for not producing readily available domestic oil when gasoline is selling for more than $4/gal, he maintained.

'You can't yell bingo'

Republicans responded that simply holding a federal lease doesn't necessarily mean oil or gas can be produced from it. "Just because you have a bingo card doesn't mean you get to yell bingo," observed Todd Tiahart (R-Kan.) at a separate briefing.

Federal government regulators were more specific at a hearing that House Republicans held earlier that morning. "Some people apparently believe that when a producer acquires a lease, it can go into production immediately. That's not the case. To even begin the process, a lessee must obtain permits and meet requirements over several years," US Minerals Management Service Deputy Director Jon A. Hrobsky said.

"The process is similar onshore where there are more small than large operators and a wide range of resources. It takes years to analyze what's there, determine if it can be produced economically and develop the necessary infrastructure," added Tim Spisak, fluid

minerals division chief at the US Bureau of Land Management.

MMS grants offshore leases for 5, 8, or 10 years, Hrobsky said. "Every leaseholder has to pay bonuses before production begins. Shooting seismic can take years. Exploratory wells need to be drilled. Not every lease has oil and gas on it and if it does, it may not be economically recoverable," he explained.

"This 68 million-acre argument is bogus. Lots of it is acreage which has been unsuccessful. Some of it is still in the process. If we want to drill fewer wells that produce more oil and gas, we need to get into prime areas," said Rep. John E. Peterson (R-Pa.).

Lack of time, equipment

Responding to a reporter's observation that Republicans say H.R. 6251 duplicates existing federal law, Pelosi said, "That's not what we hear from the industry. Some executives say they don't have the time. Others say they don't have the equipment."

Noting that congressional Republicans and the Bush administration want to expand federal leasing to more of the Outer Continental Shelf and into the Arctic National Wildlife Refuge, Pelosi said, "If [oil and gas producers] don't have equipment to drill their existing leases, where are they going to get it to drill in pristine areas? If they don't have enough time to drill what they already have, where will they find it for new areas?"

Republicans said that continued Democratic opposition to more federal leasing is a mistake. "Doing nothing is not a policy," said Henry E. Brown Jr. (SC), adding that when President Bill Clinton vetoed ANWR drilling authorization 13 years ago, he said it was because it would not supply oil for 10 years. "I'm more concerned about oil leaking from a passing supertanker and washing up on beaches in my district than I would be about production from a well 50 miles offshore," Brown said.

Tiahart said that the Appropriations Committee postponed consideration of the US Department of the Interior's fiscal 2009 budget because public support has grown for amendments that would lift congressionally imposed OCS leasing moratoriums, authorize leasing within ANWR, and overturn an oil-shale leasing moratorium. "The Interior budget bill is the best vehicle to start bringing prices down. If you have a reliable supply, it helps keep speculators at arm's length," he said.

Thelma D. Drake (R-Va.), who serves on the Armed Services Committee, said that the US Department of Defense faces the prospect of having to use emergency funds or divert money from other programs to pay for suddenly higher fuel costs. "The majority's refusal to let us explore for oil and gas and develop domestic supplies is inexcusable. The day we pass legislation opening up our own resources, we'll send a signal to the rest of the world that we're ready to regain control of our destiny," she said.

Target: oil speculators

Democrats argued that more direct action needs to be taken to curb excessive energy commodity price speculation which they said has driven up prices. "Today, we are putting oil speculators on notice," Pelosi said. She announced that she sent a letter to President George W. Bush calling on him to direct the Commodity Futures Trading Commission to use emergency powers it already has to investigate all energy futures contracts.

"Experts have testified this week before Congress that the explosion of speculation in the oil futures market could be driving up prices from $20[/bbl] to $60/bbl. Oil speculators are making money by betting against the American consumer at the pump. We want to help the American people here and now," Pelosi said.

Hoyer said several bills already have been introduced, and final legislation should be ready during July. "The Bush administration insists the run on [gasoline] prices is not due to speculation. Many experts disagree. It's just another area where the administration has taken the referee off the field," he said.

"The CFTC should use its emergency powers to drive out speculators who are pushing oil prices higher. The laws of supply and demand have been suspended. It has taken on almost a casino atmosphere. We represent Main Street instead of Wall Street on this issue," said Larson.

Emanuel said CFTC's reluctance to move against oil price speculators follows the same pattern as with home mortgage and student loans where regulators essentially had their hands tied behind their backs. "In each case where this administration [in the past] has put ideology ahead of what's working, there have been problems," he said.

'Price gouging' setback

House Democrats suffered a setback when their latest bill to require federal investigations and prosecution of alleged oil-product price gouging fell six votes short of passage on June 24 as 11 Republicans who supported a similar measure last year voted "no" this time.

"With prices rising, it makes sense that we would vote on this legislation before millions of Americans fill their gas tanks and hit the road for the Fourth of July," said the bill's sponsor, Rep. Bart Stupak (D-Mich.). "Rather than voting to provide federal protection that ensures gas and diesel prices are justified, House Republicans voted to protect the handful of unscrupulous wholesalers, retailers, and refiners raking in excessive profits from the very fuel prices crippling American families."

Republicans were equally adamant that their constituents were tired of congressional inaction to bring oil prices down. "I find it problematic that as I go home for the Fourth of July recess, I can't report progress in Congress on energy legislation to increase domestic oil and gas supplies. We're on course for a disaster in America's economic future," Peterson said.

"If the president wanted to lead, he would have lifted the presidential with-

WATCHING GOVERNMENT

Nick Snow, Washington Editor

The rest of the Western Hemisphere

Jorge R. Pinon does not want US politicians to become so concerned about Venezuelan President Hugo Chavez or a possible Chinese presence in Cuba that they overlook the rest of the Western Hemisphere.

Excluding Canada, the area supplies US 32% of the US's total oil and gas imports, Pinon said during a recent presentation to the US Energy Association. And he also thinks Mexico could face bigger problems than Venezuela.

"It does not have Venezuela's integral and inherent resources. What's more, [state oil firm Petroleos Mexicanos] has never learned how to behave in an entrepreneurial way. From a stewardship standpoint, it doesn't know how to take the country forward," Pinon said.

A former executive with Shell Oil Co., Amoco Corp., and BP PLC before his retirement in 2003, Pinon said that major oil companies have four tools in their toolbox when they negotiate with South and Latin American governments and national oil companies: capital, technology, know-how, and stewardship.

Continuity matters

"Regime continuity has become very important in the last 5 years. Majors are willing to play by the rules, but they don't like to see the rules change." said Pinon, now an energy fellow with the University of Miami's Center for Hemispheric Policy.

Pinon said it's important for US policymakers to recognize that an NOC can operate in a more entrepreneurial style than the government. That essentially has made Brazil's Petroleo Brasileiro SA one of the hemisphere's 800-lb gorillas, he said.

"[Petrobras] can't seem to do anything wrong. But it faces challenges including a 5-8 year development timeframe and lack of equipment," Pinon said. Still, he said, Petrobras and President Luis Inacio Lula da Silva "could be the wedge the US is looking for" against Venezuelan President Hugo Chavez and Petroleos de Venezuela SA.

Venezuela's potential

If Brazil is an 800-lb gorilla, Venezuela weighs in at 1,600 lb because its resources are considerable, Pinon said. Chavez has diverted PDVSA from its core function, and production from its conventional oil fields has been neglected, but Pinon said this might not last. "If the Venezuelan people under a democratic process decide to change their government, PDVSA's situation will change very quickly," he said.

Pinon said that he also hopes US companies get the opportunity to enter Cuba, which has attracted several firms from other countries. "Its production-sharing agreement is awesome. It's more commercial than Venezuela's or Ecuador's," he said.

As for a Chinese presence in Cuba—a fact that has several US politicians upset—Pinon said Sinopec Corp. has a single onshore lease and it has hired some French firms to do some seismic work there.

"I hope Cuba is not used as a political tool. It potentially has 300,000-400,000 b/d of production down the road. But its internal demand under a free market government could be 350,000 b/d," he said. ✦

GOP Senate bill would improve energy market regulation

Nick Snow
Washington Editor

US Senate Republicans introduced legislation that they said would balance developing domestic fossil fuel sources with promoting alternatives and improve energy commodity market regulation.

The bill, which has 43 cosponsors, grew from efforts by Senate Republicans to intensify the energy debate and provide a vehicle for bipartisan action to address high gasoline prices, Minority Leader Mitch McConnell (R-Ky.) said.

"It uses a three-pronged approach (conservation, innovation for newer technologies, and expanded exploration of our domestic resources) to solve America's energy crisis. It also would create thousands of jobs and help get prices down at the gas pump," he maintained.

Democrats in the House as well as the Senate oppose expanding oil and gas leases on the Outer Continental Shelf or authorizing prompt development of regulations for leasing federal onshore acreage for oil shale development. Two provisions in McConnell's bill address these issues by repealing an oil shale moratorium that Democrats inserted into the Department of the Interior's fiscal 2008 budget and by allowing coastal state governors to petition for OCS leasing at least 50 miles offshore with concurrence from their drawals first. There's been bipartisan neglect," he added.

"We are in the battle of this generation," Pelosi said. "When I became speaker, I realized the landmark battle would be energy security and climate change. It's not surprising that it has grown more intense as oil prices have gone up." ✦

state legislatures.

The bill also would increase research and development support for producing electric cars and trucks and take several actions to improve US regulation of energy commodity markets. Specifically, it would increase funding for US Commodity Futures Trading Commission operations and staffing, codify CFTC actions on position limits and transparency limits for foreign exchanges and require the CFTC to gather information on index traders and swaps dealers.

"We must expand our domestic energy production and limit the hold Middle Eastern nations have on our economy," McConnell said. "The United States is the third-largest producer of oil in the world after the Saudis and the Russians. While we must work now to reduce our dependence on fossil fuels, if we truly want to achieve energy independence, America must be allowed to take advantage of the vast energy resources we have right at home."

The bill represents the latest effort to reduce US dependence on foreign oil by addressing fundamental supply and demand problems, according to Pete V. Domenici (R-NM), the Energy and Natural Resources Committee's ranking minority member.

"While the majority has come up with excuse after excuse for opposing more production, to me the path forward should be clear. Passing a bill like this will send a strong message to the world's oil markets and the unfriendly nations we buy oil from that America has had enough. I hope that the Democrats will reconsider their widespread opposition to increased domestic production," he said.

The House Western Caucus, led by Rep. Chris Cannon (R-Utah), also planned to introduce an energy bill on June 26. ✦

EIA: Biggest energy demand growth in developing countries

Nick Snow
Washington Editor

The world's total energy consumption could grow by 50% in the 25 years from 2005 to 2030, with most of the increase coming in developing countries, reported the US Energy Information Administration in its latest International Energy Outlook (IEO) June 25.

Demand could grow by 85% in countries outside the Organization for Economic Cooperation and Development and by 19% within the OECD, which comprises most of the world's industrialized nations, according to the 2008 IEO reference case. The report assumes that economic growth outside the OECD will average 5.2%/year compared with an average 2.3%/year growth within the OECD.

Petroleum and other energy liquids are expected to continue to supply the largest part of total consumption, but their share could decline to 33% in 2030 from 37% in 2005, largely in response to world oil prices remaining relatively high, the forecast indicated in its base reference case.

The price assumptions, which do not reflect carbon constraints, were set late in 2007 and could be revised to reflect significant increases since that time, EIA Administrator Guy F. Caruso said. "We think that over the next 5-10 years, high prices will bring on new supplies that will exert downward pressure. But we're not going back to 1980s prices in the $20 range," he said as he unveiled the forecast at the Center for Strategic and International Studies.

The strongest growth in energy liquids demand may be in emerging Asian economies and would average 15-31%/year, Caruso said. In North America, biofuels should represent about half of the liquids supply growth, but a significant amount could come from nontraditional fossil fuel sources, he indicated.

Economics could improve

"The economics of developing unconventional sources, including coal-to-liquids, could become attractive with continued higher prices," Caruso said. "The current constraints on oil sands in Alberta, particularly materials and labor, should ease off." Oil sands probably will propel Canada's production growth while production within the US could increase with more Gulf of Mexico deepwater activity and greater application of enhanced oil recovery onshore, he said. "A significant amount of new US liquids production will have to come from tar sands, oil shale, and other unconventional sources," he said.

The effect of additional production from the US Outer Continental Shelf on oil prices through 2030 would be small because it would take so long to bring online, he continued. "With higher prices, there could be a difference. But the length of development time indicates the impact would be minimal," he said. The OCS could increase total US crude oil production by 200,000 b/d by 2030 if federal leasing expands into areas that currently are off-limits, he said.

Caruso emphasized that EIA's long-term forecasts are designed to suggest trends instead of specific outcomes. Nevertheless, the new IEO predicts that the world's crude oil markets will remain relatively tight. "Given current market conditions, it appears that world oil prices are on a path that more closely resembles the projection in the high-price case than in the reference case," it said.

The outlook projected that worldwide natural gas consumption could grow to 158 tcf in 2030 from 104 tcf in 2005 as it replaces oil wherever possible in industrial and electricity uses. Non-OECD nations are expected to provide a major portion of new gas

production, much of it as LNG exports. "The Middle East and Africa are at the forefront of the trend toward LNG; natural gas production in the two regions combined increased by 21 tcf [during] 2005-30 but their combined demand increased by only 9 tcf," the forecast said. Prices average about $8/Mcf in real terms under the high-price case.

"By far, the most important component in consumption is growth in emerging economies particularly China and India, and the absence of carbon constraints, which would lead to growth in carbon dioxide emissions of about 2%/year. Right now, economics and technology constraints suggest there will be no meaningful carbon capture and storage contributions before 2030," Caruso said. ✦

CAPP alters Canadian oil sands production outlook

The Canadian Association of Petroleum Producers (CAPP) has released its annual crude oil production from oil sands outlook, which is slightly altered from its earlier report.

CAPP's 2008 Canadian crude oil supply outlook evaluates two cases, both extending to 2020. The moderate growth case represents the expected outlook, and a more-aggressive pipeline planning case was also developed.

In the moderate growth case, total Canadian crude oil production, including conventional, oil sands, and Atlantic offshore, was projected to increase to almost 4.5 million b/d in 2020 from 2.7 million b/d in 2007.

In the pipeline planning case, production rises even more—to 5 million b/d.

Oil sands continue to be the main source of Canada's growing oil supply, said CAPP, which estimates industry will invest about $20 billion on oil sands development during 2008.

In the 2008 forecast, CAPP extended its anticipated oil sands growth over a slightly longer time frame, which resulted in a slightly lower production profile in the 2008 forecast than in 2007.

Oil sands outlook

CAPP took a poll of oil sands producers in early 2008 to obtain their current and planned oil sands production through 2020.

"The growth in oil sands remains significant; the potential for oil sands growth is unchanged, but this will be accomplished over a longer period," said Greg Stringham, CAPP vice-president, markets and fiscal policy.

"Even with growing world demand and higher global prices for oil, oil sands projects take substantial time and effort to address issues such as rising construction costs, labor constraints, public concerns about environmental impacts, and completing detailed regulatory processes," Stringham said.

Recent trends indicate the year-over-year decline rate for conventional crude oil production has slowed somewhat due to higher crude oil prices and that production has increased slightly in Manitoba and Saskatchewan, CAPP said. However, due to the maturity of the Western Canada Sedimentary Basin, conventional crude oil supply is expected to decline gradually over the forecast period.

In order to accommodate the expected growth in oil sands supply, 1.1 million b/d of pipeline capacity is being added from Western Canada through yearend 2010. CAPP believes that capacity should be sufficient until 2013.

"Subsequently, additional pipeline capacity will be required to meet expected oil sands growth. This new pipeline capacity will include expansions into existing markets and extensions into new markets in Eastern Canada, the US, and potentially to offshore markets," said CAPP, which represents 150 companies that explore for, develop, and produce natural gas, natural gas liquids, crude oil, and oil sands.

CAPP member companies produce more than 95% of Canada's natural gas and crude oil. ✦

SEC proposes updated reserves reporting rules

Paula Dittrick
Senior Staff Writer

The US Securities and Exchange Commission has released a proposed set of revised oil and natural gas reserves reporting requirements, and proposed changes include disclosure of estimated probable and possible reserves.

Currently, oil and gas companies report only estimated proved reserves to the SEC. Existing reserves reporting requirements were adopted more than 25 years ago (OGJ, June 20, 2005, p. 21).

SEC released its proposed rule revisions on June 26, and the agency is seeking industry response on the proposed revisions during a 60-day public comment period.

Earlier this month, SEC staff recommended that reserves reporting requirements be updated in order to provide more estimated reserves information to investors (OGJ, June 23, 2008, Newsletter).

"The ability to accurately assess proved reserves is an important part of understanding any energy company's financial position," said SEC Chairman

Christopher Cox. "But the current oil and gas disclosure rules often interfere with an investor's analysis because they are tied to outdated technologies."

The proposed revisions suggest some clarifications in terminology for reserves and resources classification.

Defining 'reasonable certainty'

SEC proposes to define the phrase "reasonable certainty," which is the standard now used in the definition of proved oil and gas reserves, yet "reasonable certainty" is not defined. Consequently, it has been the subject of disagreement within industry.

"We propose to define the term 'reasonable certainty' as much more likely to be achieved than not," said SEC's proposed rule revisions.

The SEC also wants to clarify definitions for deterministic and probabilistic methods of estimating reserves. Both methods would be allowed under the proposed rule revisions.

Companies now use deterministic methods for reserves estimates that are reported to the SEC. Some companies use probabilistic methods for estimates reserves although those figures are used internally by executives.

Previously, industry-recognized definitions covered only proved reserves based on deterministic estimating methods, which was the SEC requirement. In 1987, the Society of Petroleum Engineers (SPE) issued definitions for probable and possible reserves classifications that found wide acceptance in industry. SPE and World Petroleum Congress issued new definitions in 1997 that allowed for the probabilistic estimation of reserves.

Yearend prices

Another proposed revision would require companies to report estimated oil and gas reserves using an average price based upon the previous 12-month period. Currently, companies report reserves based upon yearend prices.

Some producers had suggested that the SEC and the US Financial Accounting Standards Board consider using average prices rather than single-day, yearend oil and gas prices as the basis for calculating estimated reserves reported in 10-K filings.

Financial Accounting Standard (FAS) 69, which FASB adopted in 1982, mandates the use of prices as of Dec. 31 of each year. Some producers said this practice distorts reserves volumes and values.

SEC said this rule change would maximize comparability of reserve estimates among companies and mitigate distortion of the estimates that arises when using a single pricing date.

Oil sands

SEC's proposed rule changes also include:

- Permitting use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.
- Allowing previously excluded resources, such as oil sands, to be classified as oil and gas reserves. Currently these resources are considered to be mining reserves.
- Requiring companies to report the independence and qualifications of a preparer or auditor, based on current SPE criteria.
- Requiring the filing of reports for companies that rely on a third party to prepare reserves estimates or conduct a reserves audit. ✦

E&Y study: US oil reserves holding flat, costs rising

Paula Dittrick
Senior Staff Writer

US proved oil reserves for 40 exploration and production companies increased 2% during 2003-07, reported Ernst & Young in a benchmark study released in Houston.

Estimated proved oil reserves held flat in 2007 at 16.1 billion bbl, however, said Ernst & Young, which compiled and analyzed annual reports filed with the US Securities & Exchange Commission. Benchmark companies hold 74% of estimated total proved US oil reserves and 68% of gas reserves according to US Energy Information Administration statistics.

The benchmark study companies are representative of the nationwide E&P industry, Ernst & Young said. The study included integrated companies, independents, and large independents. Independents were classified as large if their 2007 worldwide ending reserves exceeded 100 billion boe.

Independents reported a 7% increase in oil reserves in 2007 compared with 2006, but this was offset by a 2% decline from the integrated companies. Ending oil reserves for the large independents held flat last year.

Oil production has held steady at 1.2 billion bbl/year since 2004. The study showed production of 1.3 billion bbl in 2003. Production figures include condensate and natural gas liquids.

Estimated proved natural gas reserves showed growth. Natural gas reserves for the benchmark companies increased 47% during 2003-07. The study showed those companies had 138.6 tcf of gas reserves in 2007 compared with 129.5 tcf in 2006. Gas production grew during 2007 to 10.2 tcf, up 7% from 2006 production levels.

E&D costs spiraling

Exploration costs increased to $12.8 billion in 2007, a 165% increase from costs reported in 2003. Development costs as of yearend 2007 had grown 180% from $18.4 billion in 2003, the study showed.

Revenues from oil and gas production were $141.5 billion in 2007, up 12% from 2006. But net income only increased 4% in 2007, primarily due to rising production costs and increases in depletion, depreciation, and amortization, Ernst & Young said.

US E&P results could differ greatly from other regions of the world, said Rob Jessen, global leader for Ernst & Young's oil & gas industry studies. The US benchmark companies account for 1% of worldwide oil reserves and 2% of worldwide gas reserves.

A global benchmark study for areas outside the US is being compiled and is expected to be released by Sept. 1, Ernst & Young said.

The US segment of the report excludes government and privately owned companies, smaller public companies, and other public companies that had not filed annual reports with the SEC by Mar. 31. ✦

Survey shows US favorable for oil and gas investment

Paula Dittrick
Senior Staff Writer

The US had 9 of the top 10 jurisdictions worldwide that oil and gas executives ranked as attractive destinations for upstream investment, according to results of a survey conducted by Fraser Institute, an independent research and educational organization.

Arizona, Arkansas, Oklahoma, Alabama, and Ohio were ranked as the states having the lowest barriers for upstream oil and gas investment. They were joined by Texas, the US offshore, Kansas, and New York.

Saskatchewan was ranked sixth in the top 10 out of 81 jurisdictions in terms of having low barriers to investment. It was the only Canadian province in the top 10. Alberta ranked 29 and British Columbia, 19.

Internationally, Bolivia was ranked as the least attractive country for petroleum investment and development. It was followed by Ecuador and Venezuela. Other nations considered to be the least favorable include Chad, Iraq, Nigeria, Argentina, Sudan, and Russia.

In most cases, jurisdictions that imposed heavier tax and regulator burdens during the past year received more

negative scores than last year.

"Policymakers would do well to recognizes the consequences and weigh the costs of big government in terms of foregone investment, lost jobs, and corporate flight," said Gerry Angevine, Fraser Institute senior economist and coordinator of the annual petroleum survey.

For instance, Angevine attributes Alberta's ranking to the Alberta government's decision "to grab a larger share of oil and gas royalties."

Colorado out of favor

Stiffer drilling requirements and other regulations in Colorado contributed to that's state being ranked as the 29th worst jurisdiction. Colorado was ranked in the same league as Ukraine, Pakistan, and Indonesia for investment attractiveness.

"Survey respondents were very concerned with Colorado's changes to drilling permit requirements and other more stringent regulations," Angevine said. "The Colorado Oil and Gas Association estimates that the new rules could increase drilling costs by $60,000-600,000/well."

Alaska, which increased its petroleum production tax, was listed 22nd among the least attractive jurisdictions. California was ranked 11th. California's ranking grouped it with other high-risk nations such as Russia and Sudan.

"California's expended prohibitions on offshore drilling and concerns about environmental regulations are having a detrimental effect on the way the state is viewed by the petroleum industry," Angevine said.

A total of 396 respondents participated in this year's survey. Companies represented in the survey accounted for more than one third of the industry's global spending on petroleum exploration and production, said Fraser Institute. ✦

Brazil sets sights on increasing oil production

Eric Watkins
Senior Correspondent

Brazil will at least triple its oil reserves by exploring the new Tupi offshore area, and will use the future revenues on healthcare and education for the country, according to Brazilian President Luiz Ignacio Lula da Silva.

"This is very promising for Brazil. We have to take advantage of this oil to develop the country," Lula told Bloomberg Television. "It's a chance for the Brazilian poor to use this money as opposed to having people with a lot of oil and three or four watches and a Rolex in their pockets. We want to take advantage of these riches to ensure that Brazil can take a great leap forward."

The Brazilian president avoided estimating the exact amount of petroleum that will be produced in the areas recently discovered by state oil concern Petroleo Brasileiro SA (Petrobras). Asked whether there was a possibility of tripling the current volume of production, he said, "There must be more than that, but I don't have the exact figure because there would be a lot of speculation in the stock market."

Concerning the methods that the government will use to explore the new Brazilian discoveries, Lula said, "That is a state secret." He said only that exploration of the Tupi well in the Santos basin would take place in March. "We are going as deep as possible; we are working even more intensively."

Lula said he has changed his mind and won't seek membership for Brazil in the Organization of Petroleum Exporting Countries. "I'm under no illusion that Brazil will join OPEC," he said. "I used to be, but am no longer."

Instead, Lula expressed confidence in his country's transformation into a major producer of petroleum and exporter of petroleum products.

"I cannot discuss the size of the reserves, but I feel that Brazil is going to be transformed into a major producer. I do not want it to become an exporter of petroleum," he said. "I want Brazil to export petroleum products."

No reason for high oil price

Meanwhile, according to Lula, there is no reason for the successive rises in the price of oil. "Petroleum does not need to cost what it does; half that amount would be fine," he said.

He pointed out that the experts attribute the higher price of petroleum to several things such as rising consumption in China or the increasing use of reserves in the US. "But we are aware that the price does not need to be what it is."

He said, governments need to consider the impact of petroleum costs on food production, citing the cost of fertilizer and transportation. "I believe that the world will realize the irresponsibility of this point in time because of both petroleum and food," he said.

He said the stand by US Democratic presidential hopeful Barack Obama against purchasing Brazilian ethanol and John McCain's stand in favor of it are just part of an election strategy. "When they take office," he said, "they will begin working in terms of reality."

In fact, Lula is convinced that Brazilian ethanol will be used in the US regardless of who wins the upcoming presidential election. "Whoever wins the election there will realize that it is cheaper, generates more employment, guarantees more peace, and creates no conflict with food production."

"I'm convinced that whoever wins the election will start using ethanol made from sugar cane," Lula said. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Khodorkovsky's independence

Last week, just as millions of Americans—many of them in the oil and gas industry—were preparing for their July 4 Independence Day celebrations, the Russian government announced new charges against former OAO Yukos head Mikhail Khodorkovsky and his associate Platon Lebedev.

As you may recall, Khodorkovsky was arrested in 2003 when his jet was stormed by armed police on a runway in Siberia, and he is now serving an 8-year sentence in eastern Russia.

Speculation has it that former Russian President Vladimir Putin used Khodorkovsky's arrest and jailing as part of an effort to reassert state control over his country's lucrative energy sector.

The "new" charges against Khodorkovsky and Lebedev include money laundering and "stealing almost 350 million tons of oil," the investigative branch of the prosecutor's office said.

The same absurdity

In reply, Khodorkovsky said, "The investigators have repeated the same absurdity about me stealing the entire Yukos oil output during 6 years."

His lawyers described the charges as a slightly modified version of theft and money-laundering claims filed against him in February 2007 but never brought to trial.

Even Russia's Kommersant newspaper saw through the charges. On July 1 the paper said: "Yesterday, Mikhail Khodorkovsky and Platon Lebedev were charged with a theft of some 350 million tons of oil and laundering 487 billion roubles and $7.5 billion. You can hardly render this accusation new: Compared with the previous version, only stylistic inaccuracy has been improved, and some of the paragraphs have been swapped."

One wonders when this farce will ever end. Some Russian observers have speculated that Putin's successor, Dmitry Medvedev, could release Khodorkovsky to signal a break with some of his predecessor's policies.

Medvedev=Putin

But any hope of that seemed to have faded in early June when Medvedev rejected any outside intervention over Khodorkovsky.

"Issues related to the serving of sentences should not become the subject of interstate negotiations," said Medvedev during a visit to Berlin, his first trip to Europe since succeeding Putin earlier in May. The matter arose when a lawyer for Khodorkovsky called on Germany's leader to raise his client's case during talks with Medvedev.

"I hope that German Foreign Minister Frank-Walter Steinmeier and the chancellor, Angela Merkel, plan to discuss this subject with Medvedev," said Yury Schmidt, chief defense lawyer for Khodorkovsky.

Schmidt said he was more hopeful for his client's release following talks he held with Steinmeier during the German minister's visit to Russia in mid-May.

"Steinmeier asked me precise questions on legal procedures that would allow Khodorkovsky to be freed," said Schmidt. "This is not a question of pardoning Khodorkovsky, but of legal avenues allowing him to be freed."

Not much seems to have come of that meeting, though, apart from thinking that "Medvedev" is just another way of spelling "Putin."

Some Independence Day celebration. ✦

Japan to aid Iraq in rebuilding oil, gas industry

Eric Watkins
Senior Correspondent

Iraqi Oil Minister Hussain Al Shahristani and Japanese Minister of Economy, Trade, and Industry Akira Amari—voicing concerns over global oil prices—agreed that both countries would cooperate in a variety of measures aimed at reconstructing Iraq's oil and natural gas industry.

"The two countries confirmed that rebuilding the oil industry and increasing output are important for the stability of crude oil prices, and Japan is ready to fully cooperate to that end," Amari said after meeting with Al Shahristani.

Japan and Iraq will strengthen cooperation in a range of economic fields centering on the energy sector. They said oil and gas development and the reconstruction of existing energy-related facilities are essential for the rehabilitation of Iraq.

Basra refinery upgrade

Japan reconfirmed its commitment to implement development loans it has pledged, including one to help build refinery and export facilities in and around Basra. The ¥2.1 billion loan to Basra includes installing secondary units such as a fluid catalytic cracker.

In January, the Japan Bank for International Cooperation said it had signed an agreement with Baghdad for as much as ¥182.7 billion to restore war-damaged facilities, including ¥50.1 billion on the oil export facility reconstruction project.

At the time, JBIC said the two countries also agreed to spend ¥36.8 billion for rehabilitation of the Al-Mussaib thermal power plant; ¥30.2 billion for the Iraqi port area rehabilitation project; ¥32.6 billion for rebuilding the power grid; and ¥30.9 billion on other civic rehabilitation and construction projects.

In early June, JBIC signed additional loan agreements totaling ¥57.7 billion for the Basra water supply improvement project and reconstruction of the Kurdistan electric power grid.

Japan's oil and gas firms have reaped rewards from the investments. In April, Inpex Holdings Inc. and three other Japanese companies passed a preliminary screening of potential bidders for Iraqi oil exploration and development.

In addition, Japan Petroleum Exploration Co., Nippon Oil Corp., and Mitsubishi Corp. are among 41 of the 120 applicants to have passed the Oil Ministry's preliminary screening. The 41 include ExxonMobil Corp., BP PLC, and oil and gas companies from China, Russia, and India.

Iraq expressed hope that more Japanese companies will participate in bidding for projects to develop Iraqi oil fields, while Japan offered to train a hundred Iraqi engineers a year during 2009-13.

The Iraqi oil ministry said this week it is planning by the end of the month to announce the first round of tenders to develop its oil and gas fields.

A ministry spokesman said names of the fields, duration of each contract, closing dates for receiving bids, and other details would be made public on June 30.

The oil and gas fields include Kirkuk and Bai Hasan in northern Iraq, as well as West Qurna 1, Zubair, Rumaila, and Missan in southern Iraq. They also said two gas fields—Akkas in western Iraq and Mansoriya in the east—will be included. ✦

Supreme Court overturns Exxon Valdez $2.5 billion punitive damages award

The US Supreme Court has overturned the $2.5 billion in punitive damages against ExxonMobil Corp. for an oil spill from the tanker Exxon Valdez in Alaska's Prince William Sound in 1989.

The nation's high court said punitive damages should be limited to $507.5 million. In a ruling released June 25 in Washington, DC, the court was divided, 5-3. Associate Justice Samuel Alito had recused himself from the case because he owns ExxonMobil stock.

Associate Justice David Souter wrote the opinion, saying punitive damages could not exceed what ExxonMobil already paid to plaintiffs for economic losses. Associate Justices John Paul Stevens, Stephen Breyer, and Ruth Bader Ginsburg dissented.

ExxonMobil Chairman and Chief Executive Officer Rex W. Tillerson issued a statement saying ExxonMobil has "worked hard over many years to address the impacts of the spill and to prevent such accidents from happening in our company again."

Alaska Gov. Sarah Palin said she was "extremely disappointed" with the Supreme Court decision.

"While the decision brings some degree of closure to Alaskans suffering from 19 years of litigation and delay, the court gutted the jury's decision on punitive damages," Palin said. "It is tragic that so many Alaska fishermen and their families have had their lives put on hold waiting for this decision."

Tillerson's comments

Tillerson called the Valdez oil spill "a tragic accident and one which the corporation deeply regrets."

ExxonMobil has spent more than $3.4 billion, including compensatory payments, cleanup payments, settlements, and fines, Tillerson said.

The company cleaned up the spill and voluntarily compensated more than 11,000 Alaskans and businesses, he said.

"In the aftermath of the Valdez accident, we redoubled our long-time commitment to safeguard the environment, our employees and the communities in which we operate," Tillerson said.

The punitive damages case arose from a 1994 lawsuit.

More than 32,000 plaintiffs, including commercial fishermen, private landowners, Alaskan natives, and other individuals and businesses sued the vessel's captain Joseph J. Hazelwood, and ExxonMobil, the ship's owner and Hazelwood's employer.

The Supreme Court's ruling overturned punitive damages set by the US Ninth Circuit Court of Appeals. ExxonMobil had appealed to the Supreme Court, which heard arguments Feb. 27 (OGJ, Mar. 10, 2008, p. 30). ✦

BP: Free markets effective where allowed to work

Marilyn Radler
Senior Editor-Economics

Despite high prices, above-average economic growth drove robust global energy-demand growth last year, according to BP's latest statistical review of world energy.

Energy consumption worldwide increased 2.4% in 2007, driven by developing countries. This compares to 2.7% worldwide energy demand growth a year earlier.

Mark Finley, general manager of global energy markets for BP America, told a Houston audience June 24 that it is countries outside the Organization for Economic Cooperation and Development that are driving today's global economic growth and have accounted for 90% of all energy demand growth over the past 5 years.

These non-OECD countries have experienced an energy-intensive form of economic growth, as the world's heavy industry has shifted away from the developed OECD countries.

Global oil demand grew 1.1% last year, with robust growth in oil-exporting countries. Oil consumption growth by non-OECD oil importing countries has shown the greatest acceleration. Countries that subsidize energy prices accounted for all of the 2007 growth, Finley said, while oil demand in countries within the OECD declined nearly 1%.

Where allowed to work, high prices are effective at keeping demand in check, Finley said; US gasoline consumption, for example, has declined with higher pump prices.

Oil production slows

In its first decline since 2002, worldwide oil production fell 0.2%, or 130,000 b/d, last year. However the US posted its first oil production gain since 2000, led by onshore output in the lower-48.

Worldwide proved oil reserves were flat from 2006, totaling 1.24 trillion bbl, enough to meet current production for 41 yr, according to BP's assessment. Finley noted that estimates of the world's oil reserves keep rising, much more so due to factors above the ground, including prices, rather than due to geology.

Finley said that through 2007, the average crude prices for the first time in history increased for 6 years straight.

Rather than speculation in the oil markets, Finley said that tightening fundamentals and concerns of future market conditions are driving current prices for oil, heating oil, and natural gas. Speculation is a symptom—not a cause—of higher prices, he said.

The BP report shows that last year, natural gas consumption grew by an above-average 3.1%, although only North America, Asia Pacific, and Africa recorded above-average regional growth.

Coal was the fastest growing fuel in the world for the fifth consecutive year, as global demand rose 4.5%, above the 10-year average of 3.2%. ✦

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The second Oil Sands and Heavy Oil Technologies Conference & Exhibition is scheduled for July 15 – 17, 2008, at the Calgary TELUS Convention Centre in Alberta, Canada. Once again this conference will highlight new technology in the growing oil sands and heavy oil industry.

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MODELING GULF OF MEXICO LOST PRODUCTION—1

Field redevelopment economics and storm impact assessment

Mark J. Kaiser
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Yunke Yu
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The oil and gas industry in the Gulf of Mexico has the greatest weather exposure in the world and is vulnerable to a range of losses that include physical damage and destruction, business interruption, and pollution liability.

A number of offshore facilities, drilling rigs, and pipelines were destroyed and extensively damaged in the 2004 and 2005 hurricane seasons. The destruction from hurricanes Ivan, Katrina, and Rita was severe with 122 structures destroyed and 76 others severely damaged. The physical impact of the hurricanes to the offshore infrastructure has been widely reported in the trade press, but the financial impacts of decommissioning and the potential value of the lost production have not been examined.

The purpose of this four-part series is to examine the destroyed infrastructure from the 2004 and 2005 hurricane seasons and the likely contribution this collection of assets would have made to future production in the gulf.

In Part 1, we describe the weather risk that operators encounter and review the factors that are involved in redevelopment decisions. The impact of the 2004 and 2005 hurricane seasons on the infrastructure and production statistics in the gulf are summarized.

Weather risk

Storms and hurricanes regularly challenge and endanger the coastal community and energy infrastructure in the Gulf of Mexico.

Powered by heat from the sea, a hurricane acts as a gigantic heat engine transforming warm ocean water into powerful wind fields. The wind fields generate waves and current that interact with the built environment, increasing the stress load on offshore structures, which in some cases, leads to catastrophic failure and destruction.

Tropical cyclones are steered by the easterly trade winds and the temperate westerlies, and around their core, winds grow with great velocity and generate ferocious and violent seas. Each year around 100 tropical disturbances develop between May and November over the Atlantic Ocean. About 25 of these disturbances develop into tropical depressions, of which on average 10 become tropical storms, 5 become hurricanes, and 2-3 are likely to strike the US coast.

Storms that grow into 74 mph sustained winds are classified as hurricanes. Tropical storms traverse all parts of the gulf, and nowhere is immune

ABANDONMENT COST ESTIMATES

Table 1

Operator	Structures destroyed	Estimated cost, million $	Source[1]
Maritech	3	72-96	A
Taylor Energy	1	500	T
BP America	11	500	T
Pioneer Natural Resources	1	138	T
Mariner Energy[2]	3	35	A
Apache	11	724	A
Stone Energy	7	50	A

[1]A = 10K annual report, T = trade press. [2]Costs pertain to assets acquired from Forest Oil.

STRUCTURE DAMAGE RATE AND PHYSICAL DAMAGE ESTIMATES

Table 2

Hurricane	Year	Structures in storm path	Structures destroyed and with major damage	Damage* rate,%	Physical damage, billion $
Andrew	1992	700	87	12	0.9
Lili	2002	800	10	1	0.4
Ivan	2004	150	31	21	1.5
Katrina	2005	2,068	66	3	6.4
Rita	2005	793	101	13	3.7

*Damage rate expressed as percent exposed, computed as the number of structures destroyed and with major damage divided by the number of structures in a 50-mile envelope centered on the storm path.

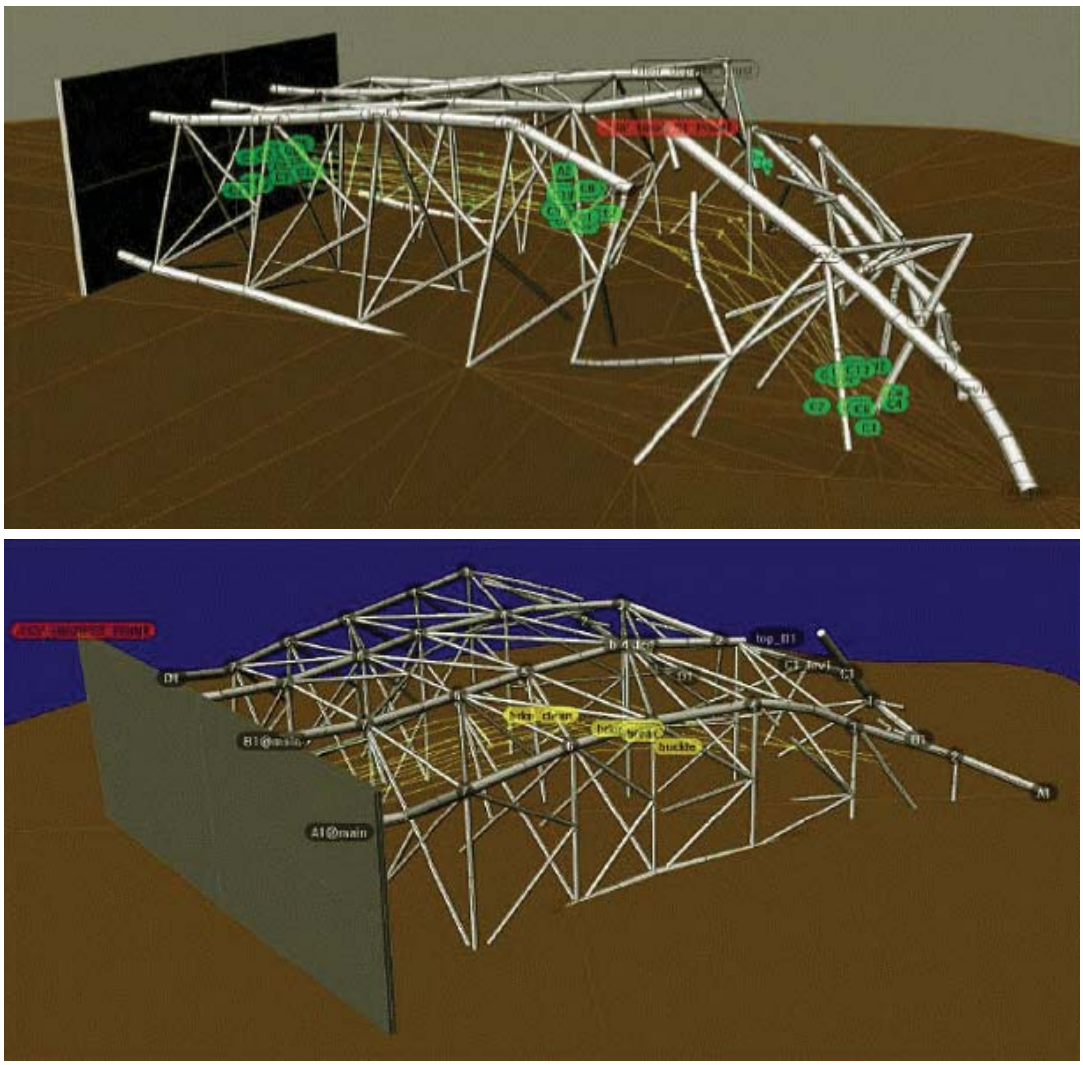
from a hit. The official hurricane season in the Atlantic basin begins June 1 and ends Nov. 30.

Weather is a significant risk in the gulf because storms and hurricanes can damage and destroy facilities, drilling rigs, and associated infrastructure; interrupt production; and delay exploration and development programs. For day-to-day operations, offshore platforms are extremely safe and historically have performed at an acceptable rate of failure.

With the appearance of a tropical storm or hurricane, however, the risks of damage and destruction increase dramatically and unpredictably because structures must sustain wind speeds, wave forces, and potential mudslides that in extreme circumstances may equal or exceed their design capacity. In addition to the physical damage that may occur, other types of losses such as control of well, removal of wreck, business interruption, and loss of production income may also be incurred.[1]

MODEL OF HURRICANE-DESTROYED STRUCTURE ON SEAFLOOR

Fig. 1



Source: Twachtman Snyder & Byrd Inc.

Cleanup operations

Structures destroyed in a hurricane are found lying horizontally on the ocean floor, often in a tangled web of steel (Fig. 1).

Structures typically do not fall cleanly; they fall as a mass. Pipes that cased the wells will bend and may collapse. Wells that are sheared off at the mud line will automatically shut-in as the platforms topple over.

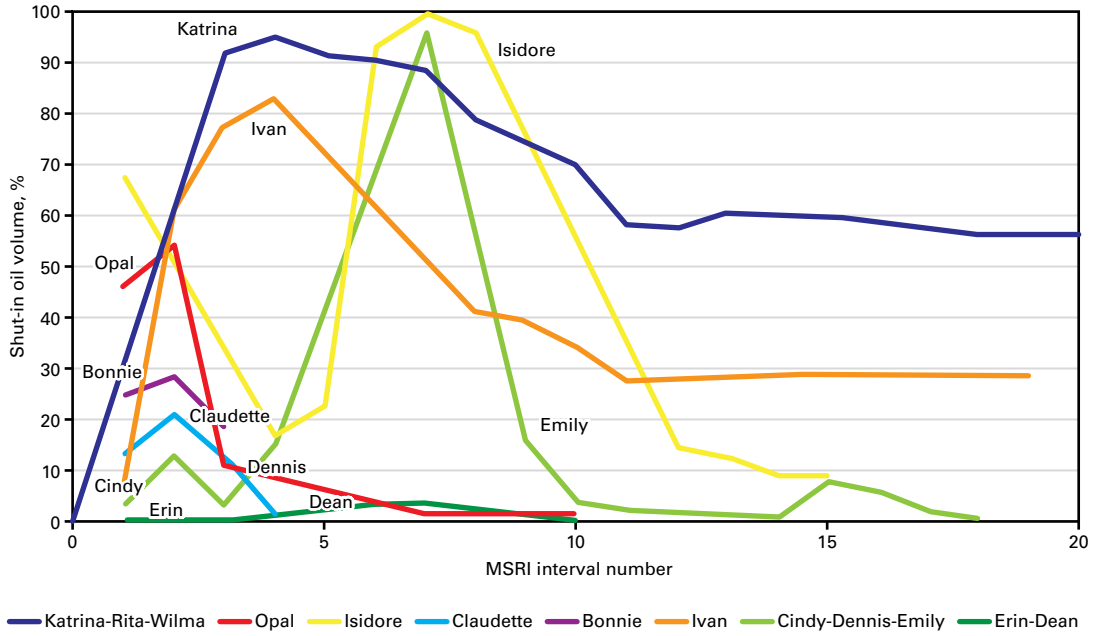
Fortunately, all gulf wells are equipped with subsea safety valves to prevent fluids flowing out the wellbore in the event of damaged and-or destroyed topsides equipment, or in the worst case, loss of the supporting structure. Debris over and around the wells must be cleared and vertical sections of pipe accessed before the wells can be plugged and abandoned.

In extreme cases, an operator may have to drill a new well to access the old well. This often requires a dredging operation and excavating mud from around the wellbores. If the well is under pressure, it will be necessary to snub in to gain access; if the well is "dead" the reentry process is only marginally simplified.

Seafloor debris is cut and moved by divers or remotely operated vehicles (ROVs). Divers do the work with limited access and poor visibility, and the tasks are often complex and require the design of new tools. ROVs can reduce the need for divers, but in most cases, they are unable to perform all the op-

SHUT-IN OIL PRODUCTION IN GULF OF MEXICO

Fig. 2



erations required and are expensive to operate.

A section of the platform may need to be cut to gain access to the wellheads. Complete removal may not be technically feasible or may pose unacceptable risks to diver personnel. If the integrity of the platform is sufficient, the platform can be lifted and transported to shore or a reef site; otherwise, the toppled structure will be cut and removed in pieces, or dismantled at site in a manner that satisfies site clearance requirements.[2]

The risk and cost involved in decommissioning downed structures are significantly higher than under normal conditions, often ranging to 5-25 times more than conventional abandonment.

In some cases, cleanup cost is significantly more expensive. Taylor's eight-pile fixed platform at Mississippi Canyon 20, for example, was destroyed by a mud flow incident during Hurricane Ivan. The structure collapsed and was moved 800 ft from its original location and submerged nearly 75% below the mud line. Estimates for cleanup have ranged up to $500 million.[3]

Abandonment cost estimates for hurricane destroyed infrastructure have not been made public because of concerns of litigation and ongoing insurance claims, but we have assembled a few cost estimates reported in the trade press and annual reports to give a sense of the magnitudes involved (Table 1).

The timetable for decommissioning depends on whether the lease is on production. If the structure is on a producing lease, owners have greater flexibility in scheduling cleanup and decommissioning activities, which will usually translate to cost savings. If the structure is not on a producing lease, the owner has one year after lease production ceases to return the seafloor to its condition prior to hydrocarbon development.

Redevelopment decisions

The decision to repair, replace, or abandon damaged and destroyed infrastructure is often difficult because of the uncertainty involved in cost estimation.

The return on investment that an owner would expect to receive depends upon the cost to fabricate and install a new platform, subsea assembly and-or pipeline interconnection-tieback, and the cost to reenter or drill new wells. Under normal circumstances, this decision is no different than an initial development decision, but in the case of destroyed or severely damaged assets, there are additional complications and uncertainties regarding the procedures and costs.

If the expected value of the remaining reserves exceeds the expected cost of redevelopment, the owner may decide that the property is worth the investment. There is little or no exploration risk, and it is possible that a field can be brought on-line at a higher rate of production to help offset the capital expenditures.

STRUCTURE AND RIG DAMAGE BY STORM

Table 3

	Ivan	Katrina	Rita
Platforms destroyed	7	46	69
Platforms extensively damaged	24	20	32
Rigs adrift	5	6	13
Rigs destroyed	1	4	4
Rigs extensively damaged	4	9	10

Source: US Minerals Management Service

DESTRUCTION BY AGE GROUP*

Table 4

Age group, years	Number
<10	24
11-20	9
21-30	17
31-40	49
>40	23
Total	**122**

*Structures destroyed by hurricanes Ivan, Katrina, and Rita.

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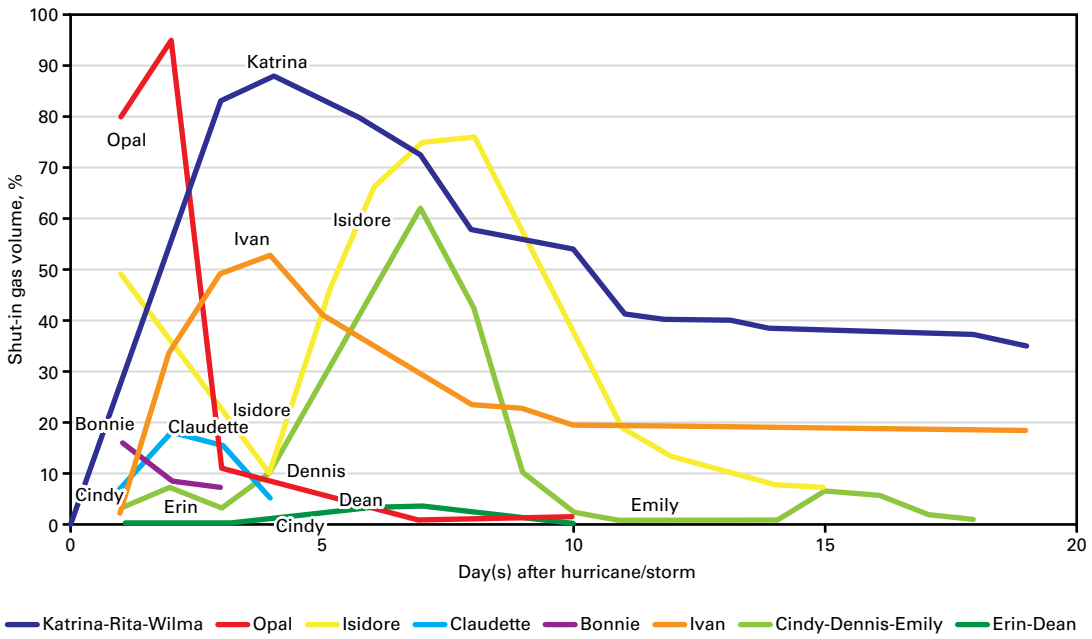
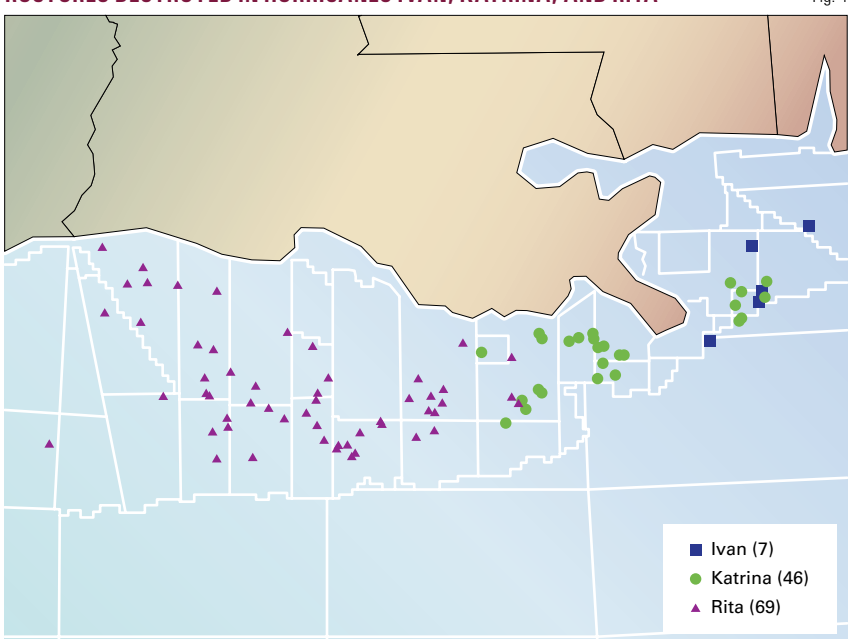
SHUT-IN GAS PRODUCTION IN GULF OF MEXICO

Fig. 3



STRUCTURES DESTROYED IN HURRICANES IVAN, KATRINA, AND RITA

Fig. 4



Assets capable of producing at high rates or those associated with significant levels of remaining reserves are more likely to be redeveloped than structures with low production rates and-or less reserves. Structures in close proximity to other infrastructure where production may be aggregated or drilling opportunities exist are also more likely to be redeveloped.

For mature fields, the natural energy of the reservoir is often near exhaustion, with production rates that are low and remaining reserves not likely to support the expenditures and payback required by investors.

Several factors work against redeveloping marginal reserves:

(1) Large commitment of resources and time required for cleanup prior to redevelopment activities.

(2) Marginal production rates and reserves, and limited upside opportunities.

(3) Risky production, since wells, even if reusable and in good condition, are old and few in number and may have mechanical problems.

Impact assessment

Aggregate losses

Losses incurred in a hurricane are a combination of physical damage and time element losses.

When production operations are disrupted, either by damage on site or elsewhere, cash flow is impacted. Insurance claims on time element coverage are typically categorized as business interruption from damage to assets (e.g., platforms, pipelines, etc.), and contingent business interruption, associated with damage to upstream facilities such as processing plants, trunk lines and refineries, owned by third-parties, which prevent production from being received.

Hurricane Ivan caused energy losses of $2.5-3 billion, while Katrina and Rita were responsible for a record $15 billion in losses.[4] In Ivan, about two thirds of the total losses were attributed to business interruption and contingent business interruption, while for Katrina and Rita, physical damage was the

Operators with three or more structures destroyed*

Table 5

Operator	Structures destroyed	Total wells	Active wells, 2005
Chevron	15	179	38
Apache	11	131	39
BP America	11	109	24
Forest Oil	11	53	11
Energy XXI	9	17	6
Stone Energy	7	37	11
Energy Resources Technology	5	29	10
Newfield Exploration Co.	5	21	10
Anglo-Suisse Offshore Partners	4	72	13
Noble	4	101	18
Mariner Energy	3	4	1
Maritech	3	28	2

*Structures destroyed in 2004-05 hurricane seasons.

Share of Gulf production from destroyed structures

Table 6

Fluid type	2000	2001	2002	2003	2004	2005
Gas	1.7	1.9	2.0	2.3	2.1	1.2
Oil	2.2	3.0	3.7	2.9	2.7	1.5
BOE*	1.7	2.3	2.7	2.6	2.4	1.3
Water	3.9	3.7	4.2	4.3	4.3	3.4

*BOE = barrels of oil equivalent, computed on a heat equivalent basis, where 6,040 cu ft of gas provides 1 BOE. The BOE stream is the combined oil and gas production output.

major cause of losses. Two thirds of the energy-related losses due to Katrina and Rita have been attributed to physical damage.[4]

Shut-in production profiles

Shut-in production statistics are reported on a daily basis by operators when hurricanes enter the gulf and in the weeks and months after the event.

In a typical hurricane, 50-100% of the oil and gas being produced at the time will be shut in 1, 2, or 3 days depending on the strength and location (path) of the storm. Obviously, the more central the storm path is relative to production fields, the greater the amount of oil and gas will be shut in. Shut-in production is usually not "lost," since after the storms pass and operators assess the integrity of their wells, pipelines, and structures, chokes and valves will be reopened and production resumed.

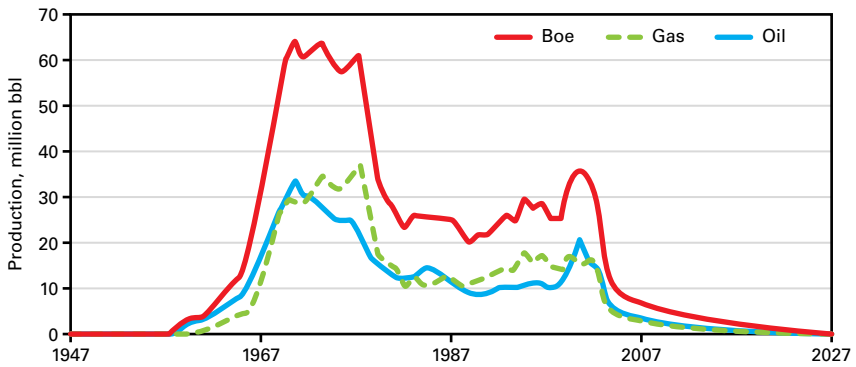
After Hurricane Ivan, damage to subsea pipelines, production platforms, and onshore processing facilities required six weeks to restore 80% of shut-in oil production and 10 weeks to restore 90% of shut-in gas production. The paths of hurricanes Katrina and Rita crossed higher-density infrastructure regions and caused more damage to the natural gas systems and processing facilities.[5]

We plot the shut-in production profiles for oil and gas for major storms over the past two decades (Figs. 2 and 3). Many factors impact the shape of these curves.

The US Minerals Management Ser-

HISTORIC AND FORECAST PRODUCTION FROM DESTROYED STRUCTURES

Fig. 5



STRUCTURE COUNT BY PRODUCTION CATEGORY

Table 7

Structure type*	Year	Production, bo/d <100	100-500	500-1,000	>1,000	Total
Oil	2000	8	18	7	5	38
	2001	8	18	6	7	39
	2002	9	15	8	6	38
	2003	6	17	7	5	35
	2004	7	16	9	3	35
	2005	13	15	1	3	32
		Production, Mcfd <600	600-3,000	3,000-6,000	>6,000	Total
Gas	2000	12	19	9	8	48
	2001	13	14	9	11	47
	2002	14	17	7	7	45
	2003	15	18	7	7	47
	2004	18	17	6	9	50
	2005	14	21	9	2	46
		Production, boe/d <100	100-500	500-1,000	>1,000	Total
All	2000	14	37	17	18	86
	2001	26	18	14	28	86
	2002	12	34	21	16	83
	2003	14	28	23	17	82
	2004	18	35	15	17	85
	2005	21	35	16	6	78

*Structures are classified as oil or gas producers according to their cumulative GOR measured in cu ft/bbl. Structures with GOR ≤5,000 are classified as primarily oil producers; structures with GOR >5,000 are primarily gas producers.

vice (MMS) requires operators to shut down facilities and evacuate personnel with the approach of extreme weather, and thus the storm path, speed, strength, and operator response impact the rate at which production is shut in and the peak value of the curves. The duration of the storm and its impact on production facilities and pipeline infrastructure will determine the plateau and slope of the shut-in curve after peak.

Many factors may complicate and delay efforts to get production back to prestorm levels, including damage to onshore support facilities and staging areas, the availability of service vessels and helicopters, and the effects of personnel dislocation and property loss.

If onshore gas processing plants are inoperable for any length of time, for example, the loss could delay a recovery of natural gas production—even if platforms and pipelines are unaffected—because gas needs to be processed before flowing to market. Production levels will return to prestorm levels if no wells, structures, or pipelines are damaged or destroyed. Production associated with destroyed wells and structures that are not redeveloped is classified as lost.

Damage rates

The amount of damage incurred from a hurricane would be expected to be roughly correlated with the strength of the storm and the number of structures in the storm path.

We tabulate exposure levels and physical damage estimates (Table 2). Damage rates are a probabilistic function, and we observe that the number of structures destroyed correlates weakly with damage estimates; e.g., the number of structures destroyed by Katrina was about half that of Rita, but Katrina's losses were nearly double.

The number of offshore structures that are destroyed or damaged depends not only on the path and strength of the storm but also the physical characteristics of the wind and wave fields and their interaction with the offshore facilities, the location of the structure relative to the storm path, design characteristics, and various other factors.

The complexity of analysis requires sophisticated meteorological, metocean, and structural modeling to normalize exposed entities to wind speed, structure type, and design specifications.[6 7]

Destroyed structures

Hurricane Ivan entered the waters of the Mississippi River delta, the area most susceptible to underwater mudslides, and destroyed seven platforms and caused significant damage to 24 other platforms.

Significant damage is defined as damage that prohibits production or requires complete structural analysis of the platform before returning to production. Thirteen pipelines were damaged. Several drilling rigs were caught in the storm's path and incurred extensive damage (Table 3).

Hurricane Katrina entered the gulf in late September 2005 as a Category 4 hurricane and destroyed 46 platforms and severely damaged 20 others. Hurricane Rita followed in mid-October 2005 destroying 69 platforms and damaging 32 others (Fig. 4). A number of semisubmersible and jack up drilling rigs broke free from their moorings during the storms and drifted throughout the gulf causing additional damage.

Most of the structures destroyed were older than 10 years, but some were in the prime of their production life cycle (Table 4). The majority of the destroyed infrastructure—with the exception of Typhoon and a small number of other developments—were mature assets in the latter part of their life cycle.

Chevron, Apache, BP America, Forest Oil, and Energy XXI owned more than half of the destroyed structures and a majority of the destroyed wells (Table 5). In total, over 850 wells throughout the gulf were destroyed by the storms.

Aggregate production

Gas, oil, and water production from the collection of hurricane destroyed structures as a percentage of total gulf production is shown in Table 6 and depicted graphically in Fig. 5 along with a forecast of future production.

Hurricane destroyed structures represented 1.2% of the total gas and 1.5% of the total oil production in the gulf in 2005 and 3.4% of the total produced water.

Structure classification

Structures are classified as primarily "oil" or "gas" producers using the cumulative gas-oil ratio (GOR), measured in cubic feet gas production per barrel oil production (Table 7).

For GOR <5,000, a structure is considered primarily an "oil" producer, while for GOR >5,000, a structure is considered primarily a "gas" producer. The amount of oil, gas, and BOE production is used to proxy the cash flow position of operators and provides an indirect indicator of the status of operations at the time of the event.

A marginal producer would likely be producing less than 50 b/d of oil or 300 Mcfd of gas, depending on structure type, water cut, oil and gas price, operating expense, and other factors, but it may vary at somewhat higher or lower levels. Production greater than 200 b/d oil or 1,200 Mcfd gas will be commercial under almost all circumstances.

As hydrocarbon prices increase, the threshold level of production which would be considered marginal decreases. Twenty-two structures, most of which were early in their life cycle, exhibit strong production levels and are the best candidates for redevelopment.

Next: Framework of a model to estimate lost production and revenue streams. ✦

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Italy

Mediterranean Oil & Gas PLC will precisely assess the contingent and prospective oil and gas resources on the BR 269 GC permit in the Adriatic Sea off Italy.

Consulting engineers certified the proved and probable recoverable oil volumes at the Obrina Mare oil and gas discovery at 20 million bbl, four times the previously estimated level. These volumes relate only to that part of the field appraised by the horizontal OM-2 well in May 2008.

The permit, in which the company holds 100% interest, is in 20 m of water adjacent to Italy's central coast west of giant Rospo Mare heavy oil field (OGJ, Apr. 2, 2007, p. 34). The permit has a number of other oil prospects and gas leads.

The company was technically unable to test the Pliocene gas sands it found in OM-2 above the oil-bearing carbonate reservoir. OM-2 flowed 900-1,000 b/d of 17° gravity oil from the Pliocene carbonate.

The gas sands correlated well with intervals that flowed 5.3-6.7 MMcfd of gas in the 1987 OM-1 discovery well, and the company believes the gas could be used in part to facilitate oil development.

OM-2 is the first offshore well operated by a junior oil and gas company in Italian waters in more than 25 years.

Tunisia

Winstar Resources Ltd., Calgary, finished shooting 401 sq km of 3D seismic covering the entire Chouech Essaida and Ech Chouech concessions in southern Tunisia.

Two rigs are under contract with one to spud by late September and the other by yearend.

A 50-mile, 6-in., 15 MMscfd pipeline to move gas from Chouech Essaida to the El Borma field sales point is to be in service by January 2009.

The Chouech Essaida-9 development well is to spud in the first week of July to tap behind-pipe zones in the adjacent No. 1 well, flowing 315 b/d of oil.

Production at the No. 8 well has increased from an initially demonstrated 119 b/d in late March to 260 b/d of 41° gravity oil and has made 19,000 bbl as of June 18. It is to be recompleted in the third quarter from the current zone and another interval that tested 391 b/d on the original completion.

Nova Scotia

Triangle Petroleum Corp. and private Zodiac Exploration Corp., both of Calgary, will drill as many as six delineation wells on the 516,000-acre Windsor block in the Maritimes basin in Nova Scotia.

The program is the second phase of Triangle's three-phase strategy for developing gas from shale in eastern Canada.

Zodiac is to pay 50% of drilling costs, up to $7.5 million, to earn a 12.5% working interest in the block. Within 30 days of fulfilling the expenditure commitment, Zodiac has the option to commit another $7.5 million for a further 12.5% working interest.

Based on Zodiac's spending the entire $15 million, Triangle would remain with a 45% working interest and continue as operator, while Zodiac would have earned a 25% working interest in the block.

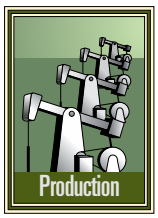
The first well is to spud in late July as a 10,000-ft vertical test to target the deeper and considerably thicker shale package in an undrilled fault block north of Triangle's first two vertical test wells.

Later wells are to test the gas content and productive potential of the Horton Bluff shales and evaluate possible overlying conventional oil and gas reservoirs. At least one horizontal well is expected to be drilled.

ERCB update expects bitumen production doubling by 2017

Guntis Moritis
Production Editor

Bitumen production will more than double by 2017 to 3.23 million b/d from 1.32 million b/d in 2007, according to the latest Energy Resources Conservation Board of Alberta update on Alberta oil sands (Fig. 1).[1]



In its update, ERCB:

- Increased by 53% the remaining established in situ reserves under active development because of new and expanded projects in Athabasca and Cold Lake regions.
- Revised the Athabasca Wabiskaw-McMurray formation in-place resources and their northeastern areal extent.
- Added a map showing reconstructed sub-Cretaceous unconformity surface with location of the Grosmont and Nisku deposits.
- Said 2007 bitumen production increased 5% from 2006 production. This includes a 3% increase from mines and a 9% increase from in situ operations.
- Said synthetic crude oil production increased by 4%.

The Alberta Energy and Utilities Board previously published this annual update, but on Jan. 1, 2008, it divided in two bodies, with the ERCB regulating oil and gas companies and the Alberta Utilities Commission regulating utilities.

ERCB in its projections assumed that US West Texas Intermediate will average $105/bbl in 2008 and rise to $138/bbl in 2017.

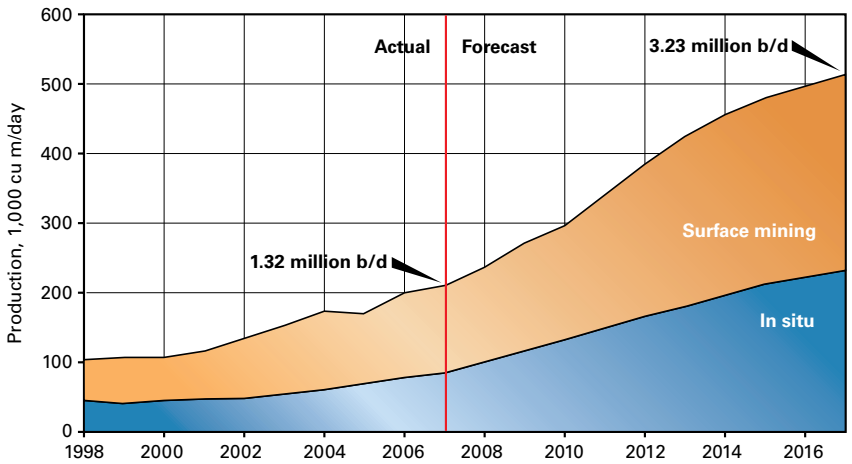
The number of planned projects for the oil sands continues to increase. OGJ published a list of the projects in various stages of completion in the June 9, 2008, issue, pp. 61-64.

The projects in Alberta's Athabasca, Cold Lake, and Peace River regions involve both mining and in situ processes. Athabasca with both mining and in situ projects produces the most bitumen (Fig. 2).

The Canadian Association of Petroleum Producers (CAPP) and the Regional Issues Working Group (RIWG) estimated in early 2007 that the industry will spend $110 (Can.) in 2007-11 and has spent $47 billion (Can.) from 1996 to 2006 on new oil sand projects.[2] Discounted for various variables, the study estimated that more likely expenditures for 2007-11 would be

PRODUCTION FORECAST

Fig. 1



Source: Reference 1

$77 billion (Can.). Fig. 3 shows CAPP's and RIWG's forecast.

Resources

ERCB's report contains the following assessment of bitumen resources in Alberta at yearend 2007:[2]

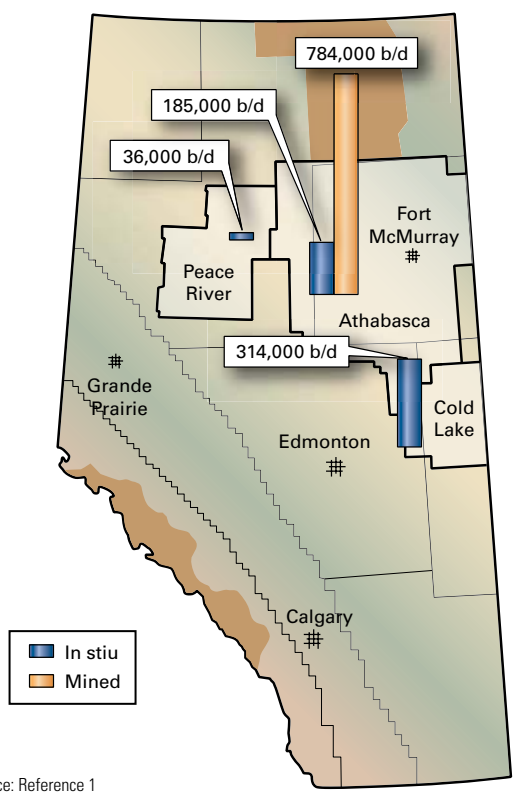
- Initial in place: 1.712 billion bbl
- Initial established: 179 billion bbl
- Cumulative production: 5.9 billion bbl
- Remaining established: 173 billion bbl
- 2007 production: 0.482 billion bbl (1.32 million b/d)
- Ultimate potential: 315 billion bbl.

In 2007, the upgrading of 286 million bbl of mined bitumen yielded 251 million bbl of synthetic crude oil (SCO), while operators mainly sold the 196 million bbl of in situ productions as nonupgraded crude, the report says. The in situ volumes also include bitumen and heavy oil produced with primary means from the same areas of the three oil sands regions.

The main deposits covered by the report are the Athabasca Wabiskaw-McMurray (AWM), Cold Lake Clearwater (CLC), and Peace River Bluesky-Gething (PRBG) covering about 54,000 sq miles.

ALBERTA 2007 BITUMEN PRODUCTION

Fig. 2



Source: Reference 1

ERCB expects to start using a 6% mass cutoff instead of a 3% mass for recoverable bitumen in future updates. Although this cutoff will reduce bitumen in place by 20% in AWM, 35% in CLC, and 50% in PRBG, ERCB expects data from additional drilling will offset these decreases.

The report says that these four deposits contain more than 64% of the total initial in-place bitumen resource and about 87% of the in-place resource found in clastics (Table 1). Of the 173 billion bbl remaining established reserves, ERCB considers 82%, or 142 billion bbl recoverable with in situ methods and the remaining 31 billion bbl recoverable with surface mining methods.

The currently active mining and in situ areas contain about 22 billion bbl out of the 173 billion bbl deemed recoverable.

Production

ERCB says bitumen production from in situ projects increased by 7.1% in 2007, compared with 2006, while production from mining projects increased by 4.3%. In 2007, the minable area produced 286 million bbl, while in situ projects produced 196 million bbl.

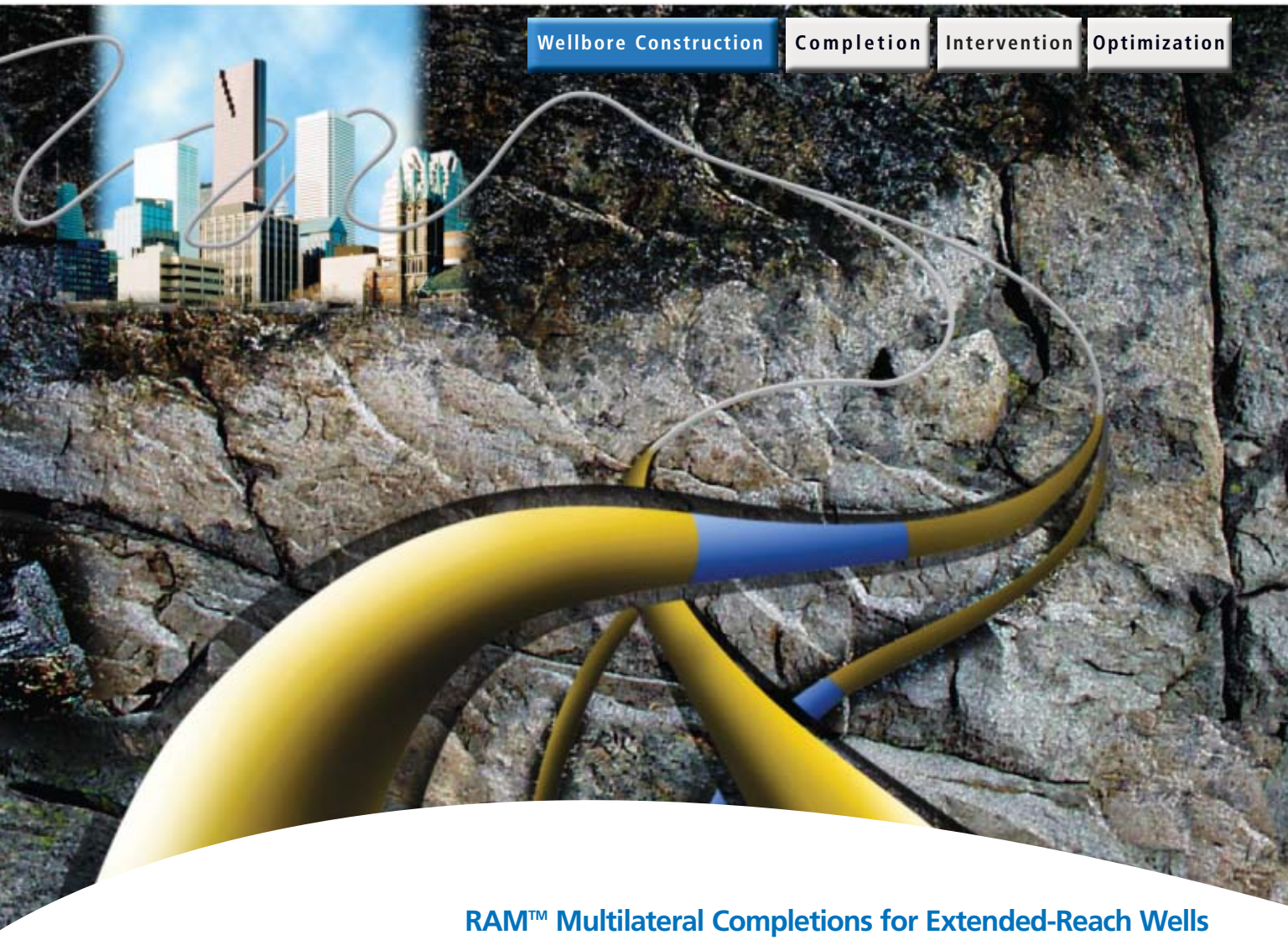
In situ recovery includes both primary methods and enhanced recovery, such as injection of steam, water, or other solvents into the reservoir to mobilize the bitumen.

The report notes that production in 2007 from the three current surface mining projects was:

1. Syncrude Canada Ltd., 367,000 b/d.
2. Suncor Energy Inc., 267,000 b/d.
3. Albian Sands Energy Inc., 150,000 b/d.

At yearend 2007, the report says about two-thirds of

Extend Reservoir Productivity



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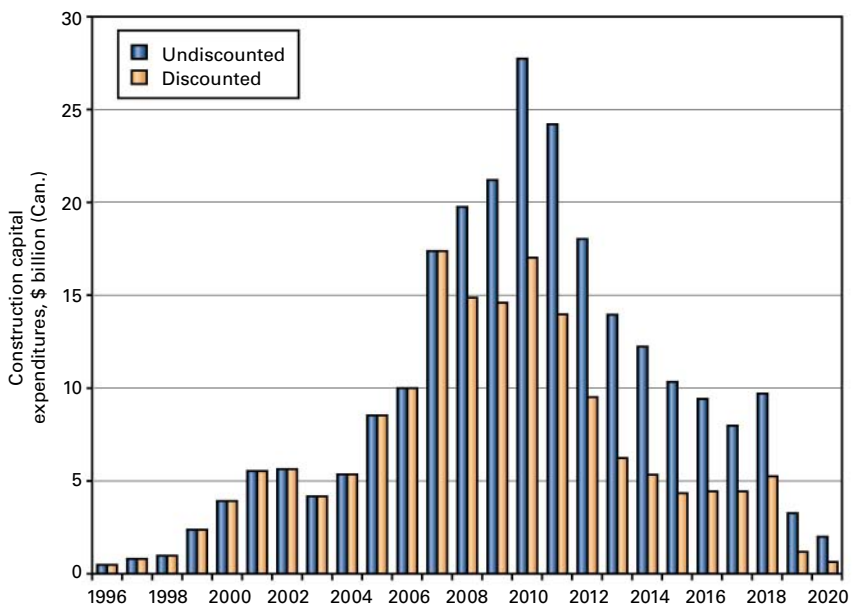
INITIAL IN-PLACE BITUMEN ESTIMATE

Table 1

Oil sands area and oil sands deposit	Initial in place, billion bbl	Area, 1,000 acres	Average pay thickness, ft	Average bitumen saturation		Average porosity, %
				Mass, %	Pore volume, %	
Athabasca						
Grand Rapids	54.6	1,703	24	6.3	56	30
Wabiskaw-McMurray (minable)	101.2	633	100	9.7	69	30
Wabiskaw-McMurray (in situ)	841.8	11,841	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	**1,380.3**	—	—	—	—	—
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	1.8	64	26	7.8	64	27
Debolt	49.1	746	78	5.1	65	18
Shunda	15.8	353	46	5.3	52	23
Subtotal	**135.6**	—	—	—	—	—
Total	**1,711.0**	—	—	—	—	—

OIL SANDS EXPENDITURE FORECAST

Fig. 3



Source: Reference 2

the initial minable established reserves were under active development. Developments that ERCB considers active are the three on production and also Fort Hills, Horizon, and Jackpine.

Futures sources of production from minable resources include:

- CNRL's Horizon project with proposed production starting third-quarter 2008.
- Shell Canada's Jackpine mine with production expected to coincide with completion of the Muskeg Mine expansion in late 2010.
- Petro-Canada-UTS Energy-Teck Cominco's Fort Hills project with production proposed by 2011.
- Imperial Oil-ExxonMobil's proposed multistage Kearl mine with start-up expected in 2011.
- Total E&P Canada Ltd.'s proposed multistage Joslyn North mine with production expected in 2013.

With these projects, ERCB expects total mined bitumen production to reach 1.76 million b/d in 2017, up from 0.78 million b/d in 2007.

ERCB notes that its outlook does not include Synenco Energy-SinoCanada Petroleum's Northern Lights mining and extraction project and UTS's Equinox and Frontier project. If completed,

production from these projects would come on stream after 2017, ERCB expects.

Fig. 3 shows 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 report says is generally at a premium to light crude oil.

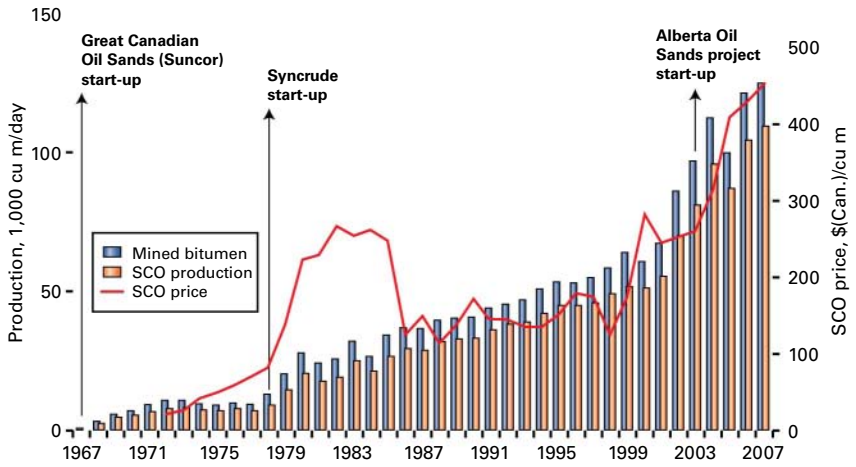
Companies have drilled most in situ producing wells in the oil sands as deviated wells from pads to minimize the drilling and production footprint. From 1985 through yearend 2007, 34,276 wells have been drilled to explore for and develop the oil sands. In 2007 of the 4,295 wells drilled in the oil sands, 1,376 were development wells and 2,919 were exploratory. About 8,900 wells were on production during 2007, with the average well producing 62 bo/d (Fig. 5).

Production from the Cold Lake region accounts for 59% of the in situ production, with another 35% produced in the Athabasca region and 7% in the Peace River region, according to the report.

ERCB expects in situ bitumen production will reach 1.46 million b/d in 2017.

Mined production

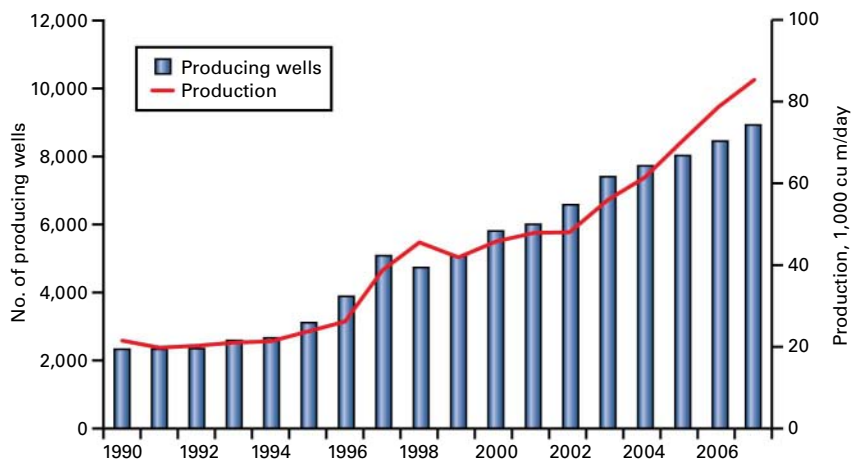
Fig. 4



Source: Reference 1

In situ production

Fig. 5



Source: Reference 1

Proposed pipelines

The increase bitumen production will require additional pipelines (Fig. 6).

ERCB's report lists the following expansion plans.

• Inter Pipeline Corridor pipeline (7 in Fig. 6) expansion project includes construction of a 42-in. diluted bitumen line, a new 20-in. products pipeline, tanks, and upgrades to existing pump stations along the existing pipeline from the Muskeg River mine to the Edmonton region. The expansion will increase diluted bitumen capacity to about 465,000 b/d by 2009 and will support further expansions beyond 2009 by adding intermediate pump stations.

• Pembina pipeline expects construction of the Horizon pipeline (10) to be completed in July 2008 and to have an initial capacity of 250,000 b/d. The project includes twinning the existing Syncrude pipeline (8), resulting in two parallel, commercially segregated lines, one dedicated to Syncrude and the other to CNRL's new Horizon oil sands development. Also included is the construction of a new 48 km, 20-in. pipeline from the Horizon site 70 km north of Fort McMurray to the AOSPL terminal.

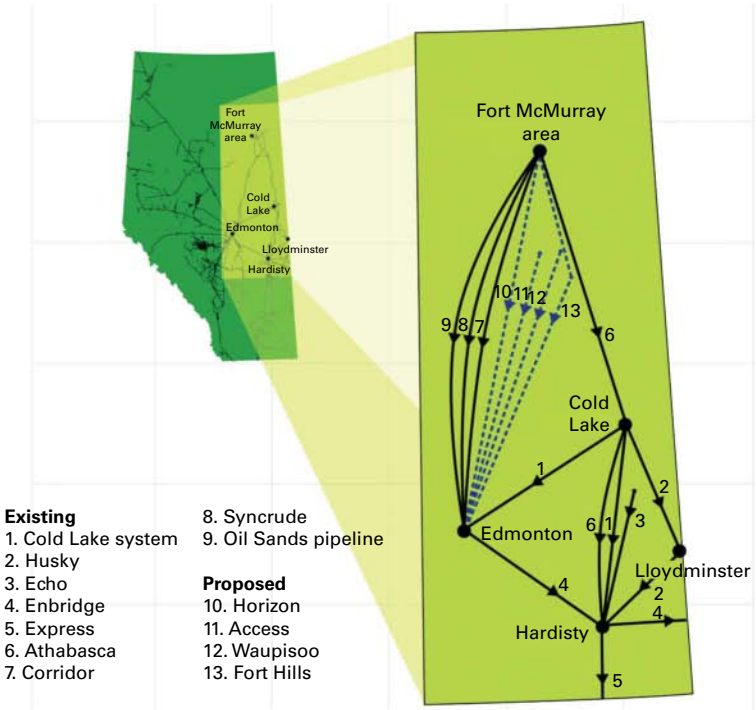
• Access pipeline (11) will transport diluted bitumen from the Christina Lake area to facilities in the Edmonton area. Initial pipeline capacity is 150,000 b/d, expandable to 400,000 b/d. Access has completed construction and expects start-up in 2008.

• Enbridge's 390-km Waupisoo pipeline will move blended bitumen from the Cheecham terminal, south of Fort McMurray, to the Edmonton area. The Waupisoo Pipeline 2008 will start operating in 2008 with a 350,000-b/d initial capacity, expandable to 600,000 b/d.

• Enbridge's preliminary plan for the Fort Hills pipeline system (13) includes a blended bitumen pipeline from the mine site north of Fort McMurray to the upgrader site in Sturgeon County. The

ALBERTA BITUMEN PIPELINES

Fig. 6



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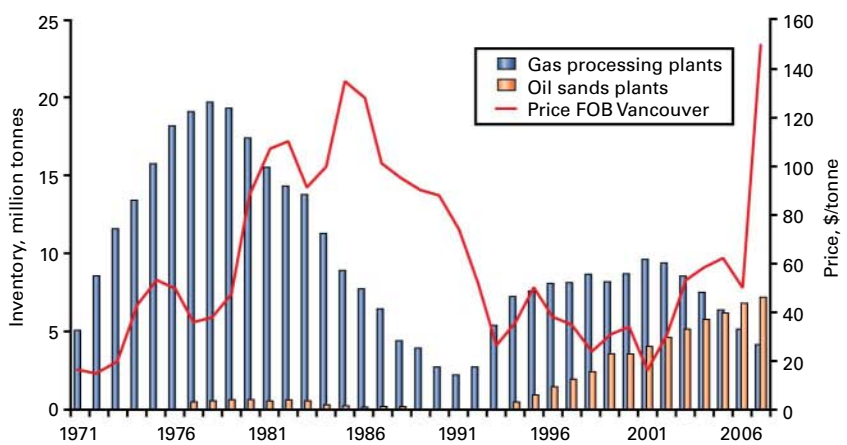
ALBERTA'S SULFUR

Fig. 7



Source: Reference 1

system will have a 125,000-b/d capacity and a 70,000 b/d parallel diluent return pipeline. Enbridge may complete the pipeline by mid-2011.

By-products

Two by-products of bitumen upgrading are petroleum coke and sulfur.

Alberta has amassed large stockpiles of petroleum coke that in 2007 reached more than 50 million tons. ERCB's report says the petroleum coke produced in the delayed-coking operation for upgrading bitumen is a potential source of energy through gasification. This energy source could reduce natural gas use in the oil sands.

Suncor has been burning sulfur-rich coke in its boilers for decades at its mine near Fort McMurray and is responsible for most of the total coke use as a site fuel. The company has also sold petroleum coke to Asian markets since 1997, mostly Japan, according to ERCB. In addition, Syncrude began using coke as a site fuel in 1995, and ERCB says the company is seeking alternative uses for its coke surplus such as using it as a reclamation material.

Sulfur is another by-product of oil sands. Its price has recently increased from $50/tonne in midyear 2007 to the $150-350/tonne range, according to ERCB's report (Fig. 7). ERCB estimates that remaining sulfur reserves in Alberta decreased by 3% in 2007, with China being the major importer. ERCB notes that exports to China in 2007 decreased by 24%, compared with 2006, because of competition of exports from the Middle East.

China uses sulfur for producing sulfuric acid and producing phosphate fertilizers.

ERCB estimates that about 208 million tonnes of elemental sulfur will be recoverable from the 5 billion cu m of remaining established crude bitumen reserves in the surface minable area. The reports says the 40.5 tonnes sulfur/1,000 cu m of crude bitumen ratio reflects both current operations and expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-minable crude bitumen reserves. ✦

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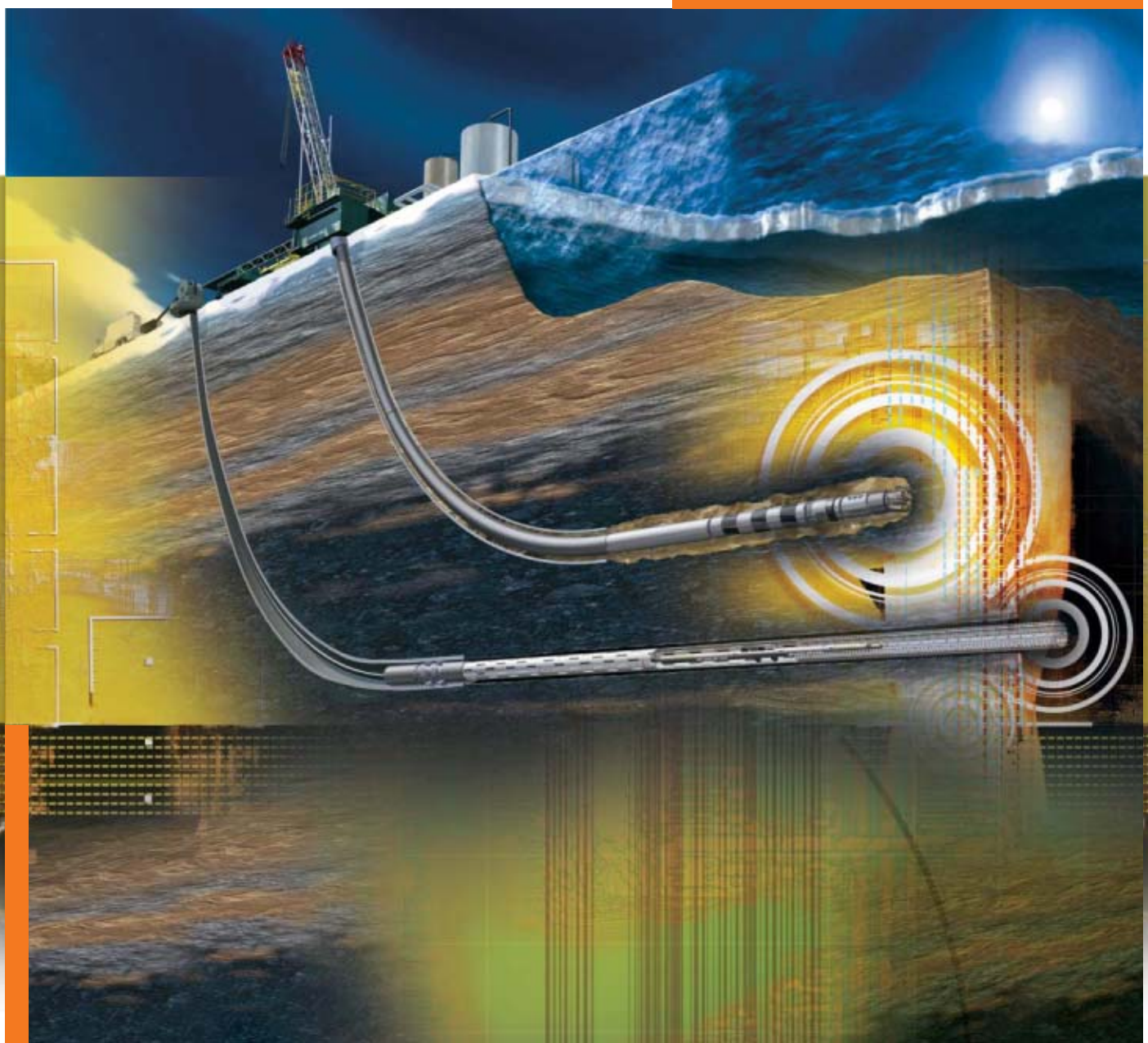

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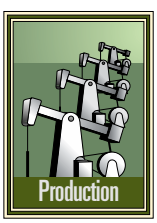


As Canadian oil sands production increases, producers are adopting varied strategies in marketing the bitumen blends and synthetic crude oil (SCO). Some producers seek to minimize capital cost and accept a low price and possible market risk with bitumen production. Others are willing to invest in upgrading or refining of bitumen to add value and perhaps reduce market risk.

Bitumen produced from oil sands generally is available to the market as a diluted bitumen blend or SCO. The supplies of both diluted bitumen and SCO are increasing and forecasts show this trend continuing (Fig. 1)

Traditional markets have included Canada and the northern tier of the US, but some supplies are starting to move farther south. Some oil sands producers have expressed interest in accessing new markets and several pipeline companies have offered proposals for transportation. Potential new markets include the US Gulf Coast, East Coast, West Coast, and Asia (Fig. 2).

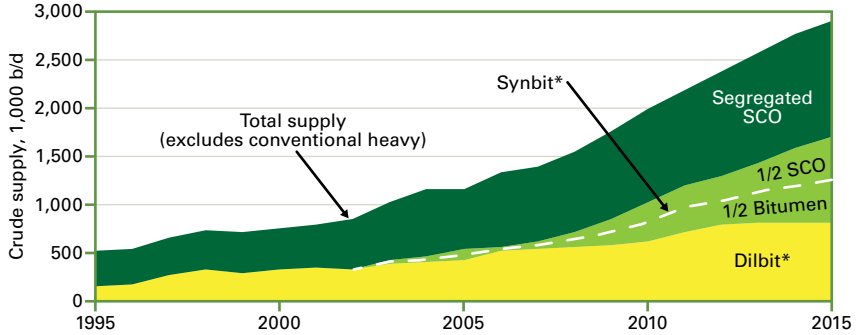
On the other hand, some refiners in the traditional markets have announced plans for facilities to use more oil sands crude, especially diluted bitumen. Through acquisitions and joint ventures, oil sands operators and refiners are working to secure their markets and supplies. Pipeline projects are under way to provide deliveries within these markets.

Historically, producers have diluted bitumen for shipment in pipelines using condensate, in a blend commonly referred to as DilBit. In some cases, they have used SCO as diluent, yielding an SCO blend called SynBit.

Most SCO has been light sweet crude with no vacuum resid, but upgraders also have produced medium-heavy sour SCO. The quality depends on the upgrading technologies employed. The

OIL SANDS CRUDE SUPPLY

Fig. 1



*Some bitumen blend in Western Canadian Select (WCS) or other blends.

future availability of various crude types will depend on bitumen production and diluent selection as well as upgrading capacity and technology.

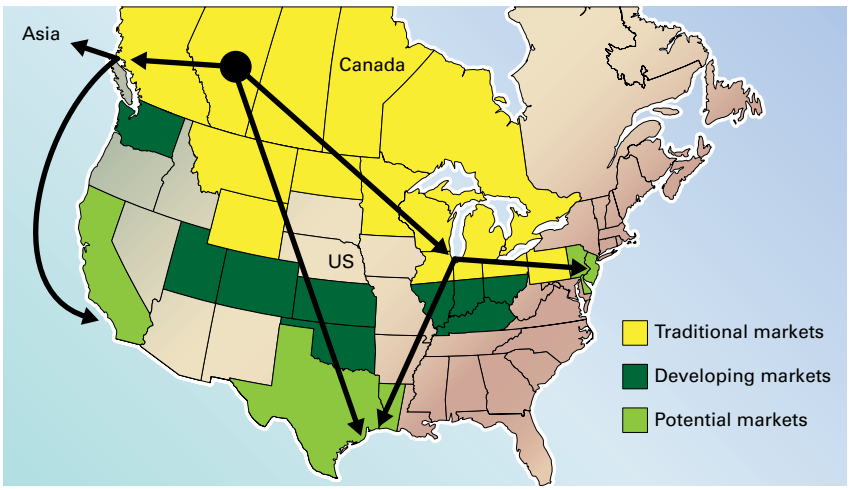
Synthetic crude oil

In Alberta, bitumen upgraders produce the SCO, most of which has been light sweet SCO (about 32° gravity and less than 0.2% sulfur) with no vacuum resid. SCO production reached about 800,000 b/d in 2007. This is predominantly from resource-based projects (Suncor Energy Inc., Syncrude Canada Ltd., and Athabasca Oil Sands Project (AOSP) at Scotford), but Husky Energy Inc.'s stand alone upgrader at Lloydminster produced about 53,000 b/d.

Purvin & Gertz estimates that about 600,000 b/d was light sweet SCO with no vacuum resid and 200,000 b/d was medium or heavy SCO with high sulfur content as well as more vacuum gas oil (VGO) or vacuum resid. Forecasts indicate production will rise in the next few years with expansions by Suncor and AOSP and upgrader start-ups at the OPTI/Nexen Long Lake project and the Canadian Natural Resources Ltd. (CNRL) Horizon project.

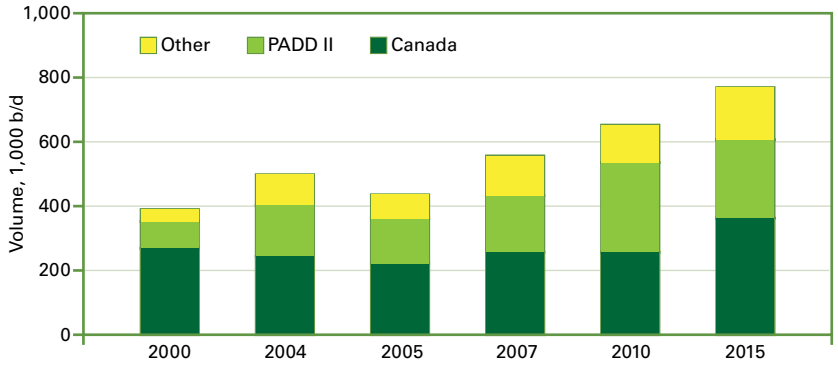
Before the start-up of the AOSP upgrader by Shell Canada Ltd. at Scotford, Canadian refineries around Edmonton and Sarnia processed most of the SCO

OIL SANDS MARKET OUTLETS Fig. 2



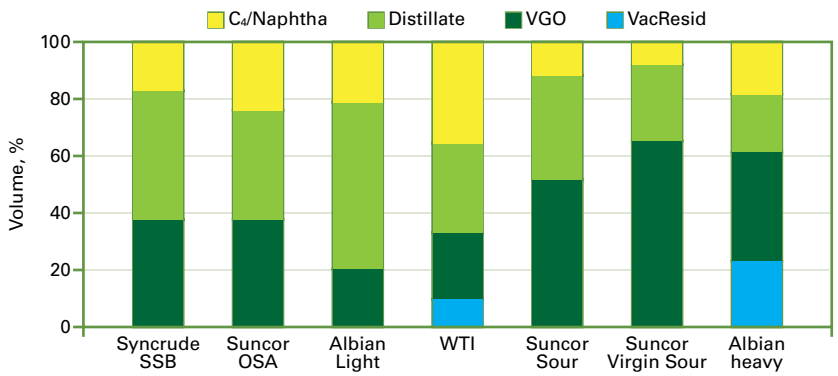
SWEET SCO DISPOSITION

Fig. 3



SCO VS. WTI DISTILLATION

Fig. 4



(Fig. 3). Most have extensive hydroprocessing facilities and use equity crude.

With the AOSP start-up in 2003 and expansions by Suncor and Syncrude, SCO production and exports have risen. Exports fell in 2005 following outages at the upgraders but recovered by 2006.

With growing production, SCO exports likely will rise. Some of the main US importers of SCO have included Sunoco, Marathon Oil Co., and Sinclair Oil Corp. Although US imports of SCO have risen, the SCO price remains strong, and there have been no special projects announced to handle more SCO.

The lack of SCO refining projects could limit SCO demand in the northern tier, so that SCO may need new markets. Movement to more distant markets, however, may weaken the SCO price and provide more incentive to add SCO hydroprocessing facilities at existing refineries within the traditional markets.

Fig. 4 compares SCO distillations with West Texas Intermediate (WTI). The qualities of SCOs vary, depending on the upgrading technologies and blend strategies used.

Coking followed by hydrotreating produces SCO without vacuum resid. AOSP uses LC-Fining/hydrotreating and produces both Albian Light and Albian Heavy SCO. The Albian Light has less VGO than others. Syncrude and Suncor OSA have a relatively high proportion of VGO that may exceed fluid catalytic cracker (FCC) capacity at some refineries.

The SCOs produced by coking and hydrotreating tend to be fairly aromatic, so that diesel fuel and jet fuel qualities have been poor to marginal, and VGO is fairly refractory for FCC units, limiting conversion. Diesel cetane has improved from as low as 33 to 40 and some newer projects expect to exceed 45. For example, the new OPTI process configuration uses VGO hydrocracking and this is expected to reduce aromaticity.

The absence of vacuum resid in SCO can limit operations in conventional, crude, and vacuum units due to heat integration, tray loading etc., so that companies generally run SCO with other crudes. Of course, refineries with cokers or asphalt production cannot use bottomless crude except perhaps to fill other process units.

As mentioned, the AOSP produces Albian Heavy SCO that contains unconventional LC Finer bottoms. Suncor produces a variety of sour SCOs with varying amounts of VGO, vacuum resid from bitumen, and cracked components.

BA Energy Inc. is planning to use its proprietary deasphalting and pyrolysis processes to produce a cracked, sour SCO. Ivanhoe Energy Inc. recently announced plans to develop an in situ and upgrading project using its proprietary HTL cracking process that would produce a cracked, sour SCO. Others have considered deasphalting to avoid diluent, thus producing a heavy sour crude.

As more refiners in the US Midwest add facilities to process heavy bitumen blends, they will have less interest in using a bottomless SCO. Thus, the potential capacity for light SCO in this traditional market may fall over time.

New markets may become interested in light SCO. The US Gulf Coast and East Coast already use light SCO from Sincor in Venezuela. The large US Gulf Coast market could absorb Canadian SCO if delivered at the right price, but the cost of delivery to the Gulf Coast may reduce the netback price of SCO.

The US East Coast refineries import light sweet crudes primarily. Most do not have cokers but have relatively large FCC capacity, so that they may be good candidates to use SCO (Fig. 5). Fig. 5 shows large FCC/hydrocracking capacity in California. This, however, is associated with coking, so that light SCO without bottoms is less suitable.

Refineries in Japan use light sweet

and light sour crudes. Japan is concerned about competition for Middle East crude. The refineries have very little coking capacity and their FCC capacity is small compared with North America. They may also be candidates for SCO although SCO with less VGO might be of greater interest.

As noted, a potentially significant market for SCO is diluent use in SynBit that typically contains about 50% bitumen and 50% SCO. If there were a large demand for SCO as diluent, this would reduce the supply of segregated SCO and strengthen the price. On the other hand, if companies imported more condensate and naphtha for diluent, this would reduce the demand for SCO as diluent and leave more segregated SCO with a weaker price.

Bitumen blends

Upgrading provides a market outlet for bitumen. Within Alberta, most of the upgrading occurs as part of integrated resource projects. To date all the mining projects have upgraders although the AOSP upgrader is not onsite. The OPTI/Nexen Long Lake project will integrate in situ production with upgrading.

In 2007, resource upgraders produced about 650,000 b/d of SCO. Companies have plans for expansions of existing projects. The new Fort Hills upgrader project, led by Petro Canada, will be in the Fort Saskatchewan area, although Total E&P Canada Ltd. and StatoilHydro Canada Ltd. have delayed plans for their upgraders. Husky cancelled its standalone upgrader at Lloydminster and development has slowed for the standalone upgraders planned by BA Energy and North West Upgrading Inc.

In 2007, in situ sites produced about 500,000 b/d of nonupgraded bitumen. Most of the bitumen growth will be from in situ projects although mining projects could produce and sell bitumen if the extraction process can meet bs&w specifications.

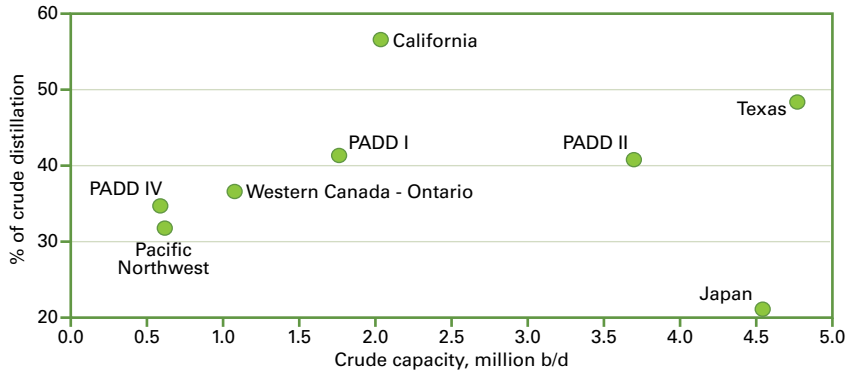
Without upgrading, companies must dilute bitumen with lighter petroleum to meet pipeline specifications for density and viscosity. Condensate historically provided most of the diluent, although companies have used SCO and other light streams. Some DilBits such as Cold Lake, Peace River, and Wabasca go directly to market.

Since 2005, companies have blended some of the DilBit and all of the SynBit with conventional heavy crudes into Western Canadian Select (WCS). DilBits, WCS, and conventional heavy crudes compete in the market.

As bitumen production grows, producers will need more diluent. Producers already use nearly all the Canadian condensate as diluent, so that future diluents are likely to be imported condensate and SCO. Some naphtha also may be recycled from Midwest refineries. The future supply of bitumen blend will depend on bitumen production, upgrading capacity, and the source and type of diluent used.

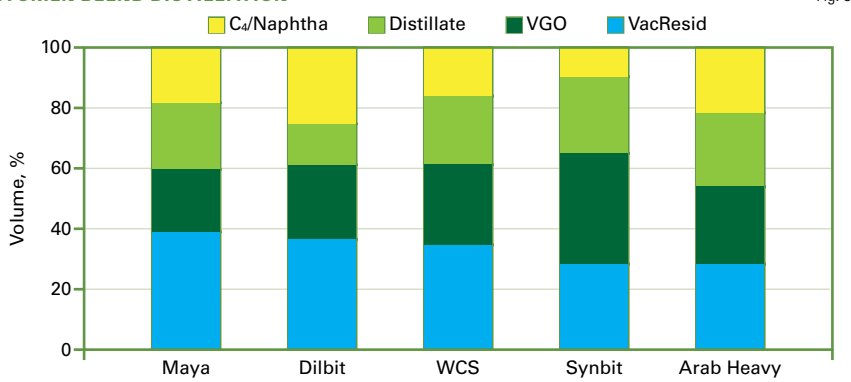
FCC/HYDROCRACKING

Fig. 5



BITUMEN BLEND DISTILLATION

Fig. 6



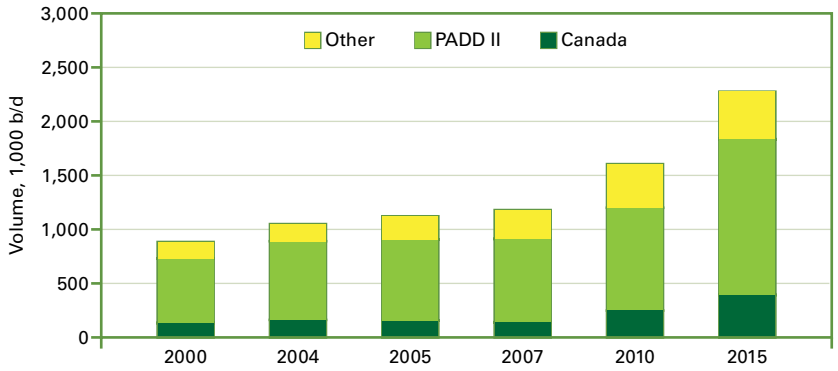
Bitumen blend qualities vary due to the bitumen quality as well as the quality and ratio of diluent in the blends. Fig. 6 compares distillations.

DilBit with about 25% condensate contains around 36% vacuum resid. SynBit with about 50% SCO contains about 28% vacuum resid and about 36% VGO. Refineries need large cokers to process DilBit and large FCC units to process SynBit. The uncertainty of diluent sourcing and the impact on bitumen blend quality make planning for new refinery projects difficult. The sulfur distribution varies due to diluent blending. Some of the bitumen blends from Athabasca and Peace River have high total acid numbers (TAN), so that refiners may require special metallurgy to process these blends.

By far the largest market for Canadian heavy crudes has been the US Petroleum Administration for Defense District II (PADD II), including refiner-

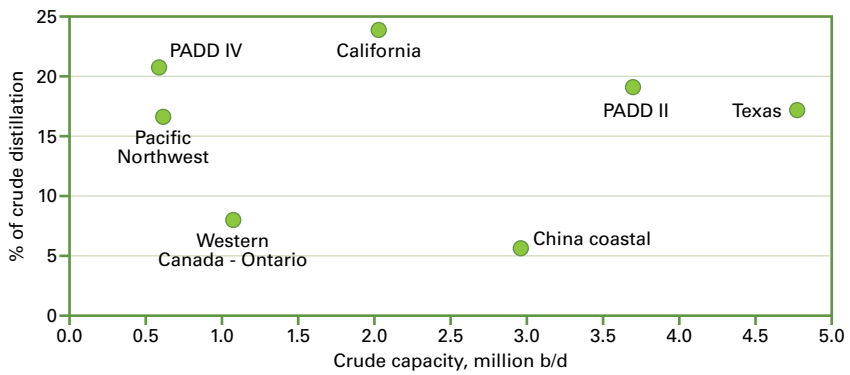
WESTERN CANADIAN HEAVY CRUDE DISPOSITION

Fig. 7



COKING/ASPHALT

Fig. 8



ies near Minneapolis and Chicago and more recently Wood River, Ill. (Fig. 7). Other markets include Western Canada, Ontario, Montana, and California. Following completion of pipeline reversals in early 2006, Canadian heavy crude has been moving to Cushing and the US Gulf Coast.

Many refiners in the traditional market have large coking capacity (Fig. 8). With wide light-heavy crude price differentials and an expectation of more heavy crude supply, some refiners have announced plans to increase coking capacity at their refineries to use considerably more bitumen blends.

Some of the larger projects include WRB Refining (a ConocoPhillips-EnCana Corp. joint venture) at Wood River, BP PLC at Whiting, Ind., and Marathon at Detroit. Husky, a heavy oil producer, also purchased the Lima, Ohio, refinery and formed a joint venture with BP for the Toledo, Ohio, refinery.

These projects could add considerable capacity for heavy crude, so that the amount available for new markets will depend on Midwest refinery projects and bitumen production increases.

Potential new markets for bitumen blends include the US Gulf Coast, California, and Asia. The large Gulf Coast refining market uses more than 2.5 million b/d of heavy crude and companies have plans for more upgrading, but they also have concerns about heavy crude supplies from Venezuela and Mexico. To meet future demand, several pipeline proposals plan to deliver Canadian crudes to the Gulf Coast from Alberta via Chicago or Cushing.

California has experienced a decline in production of its heavy crude exceeding 100,000 b/d in 5 years, but imports have increased by more than 200,000 b/d, mostly from Latin America. Proposed pipeline expansions and new pipeline projects proposed from Alberta to the British Columbia coast would allow Canadian exports to California or Asia.

Bitumen blends are heavier than most crudes used in Northeast Asia. If Chinese companies participate in future oil sands production, however, they may also add heavy crude processing at their refineries.

Greenhouse gases

Oil sands crude faces a threat from the US market due to its greenhouse gas (GHG) footprint. The 2007 US Energy Independence and Security Act appears to restrict use of oil sands crudes by federal agencies that includes the US military. "Alternative or synthetic fuels including fuel produced from non-conventional petroleum resources" are restricted if the life cycle GHG emissions exceed those from using conventional fuels. The issue has had debate and lobbying and even short-term waivers, but uncertainty remains. Resolution ultimately may depend on the outcome of the 2008 US federal election. This may provide an impetus for a Canadian west coast pipeline to supply Asia.

California proposes to reduce GHG emissions after accounting for life-cycle generation including the upstream production. This would likely affect oil sands crude imports although they would compete with California heavy crudes produced with steam. Because California would use carbon trading, the penalties are uncertain. Several other states have adopted the California program but the US Environmental Protection Agency has disallowed the proposal. This issue is now in court, adding to the uncertainty.

Production of oil sands is energy intensive. Canada and Alberta also are moving to reduce GHGs long-term. Bitumen produced by in situ methods requires fuel for steam. Oil sands mining and extraction requires fuel for steam and power. Upgrading requires fuel and hydrogen feedstock.

The upgrading process falls between production and refining and is optional, so that GHG policies may inhibit up-

grading in Alberta. On the other hand, some are promoting carbon capture and storage (CCS) for Alberta and this may reduce the GHG footprint. It may even allow or encourage gasification of coke or heavy oil for hydrogen and syngas because this would concentrate the CO_2 by-product.

Future needs

The expected growth in bitumen and SCO production will require growth in markets either through expansion of traditional markets or access to new markets, as well as more pipeline capacity.

The availability of different crude types will depend on several factors. These include oil sands production, diluent sources and types, and upgrading capacity and technology.

Companies are modifying refineries in the traditional markets to handle more bitumen blends. The need for new markets will depend on the growth in bitumen supply. The US Gulf Coast market is of interest due to its large size and complexity. Other potential markets include the East Coast, West Coast, and Asia.

Refineries in the traditional markets do not appear to be planning for more SCO. If oil sands upgrading develops as forecast, companies will need access to new markets and pipelines.

The selection of markets and transportation costs will affect future prices of oil sands crudes. ✦

The author

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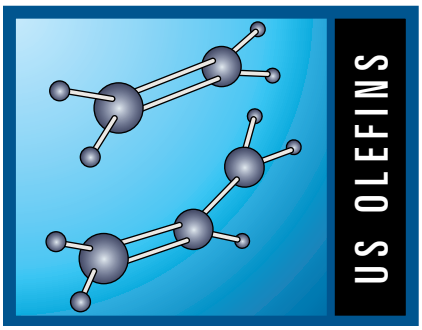
FIRST-HALF 2008

High ethane demand tightens coproduct propylene supply

Dan Lippe
Petral Worldwide Inc.
Houston

An increase in ethane cracking contributed to reduced coproduct propylene supply during first-quarter 2008. Because gas-plant ethane production will likely continue to increase during second and third-quarter 2008, ethane cracking will remain strong and may set additional records. Concurrently, however, coproduct propylene supply will remain tight.



The trend toward a lighter feed slate persisted during first-quarter 2008 and into May. Feedstock demand for ethane reached a new record high of 847,000 b/d in December 2007 and averaged 800,000-820,000 b/d in first-quarter 2008, although two large ethylene plants with significant ethane demand were out of service for turnarounds in February and March.

Despite the minor slump in total ethane demand during first-quarter 2008, ethane's share of fresh feed in multi-feed crackers reached a record high of 34.5% in March 2008. Furthermore, ethane's share of total fresh feed for all ethylene plants averaged 50.3% in first-quarter 2008 and reached 52.3% in March.

US ETHYLENE FEED SLATE

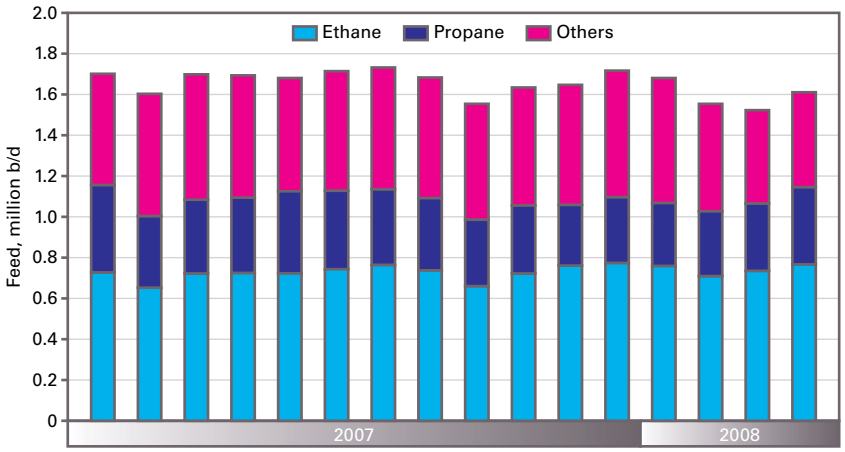
Table 1

	Feed type, 1,000 b/d			
2007	**Ethane**	**Propane**	**n-Butane**	**Naphthas, gas oils**
September	742.2	302.6	26.6	499.1
October	800.6	314.6	43.7	494.1
November	835.8	277.8	29.1	525.9
December	847.1	305.7	21.9	557.1
2008				
January	836.4	292.0	8.1	565.2
February	783.6	298.1	17.3	482.4
March	811.1	308.0	23.7	408.0
April	845.1	348.9	42.1	396.3

Source: Petral Monthly Olefin Feedslate Survey

US ETHYLENE PLANT FEED SLATE

Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

Olefin plant feed slates

Ethylene industry demand for fresh feed averaged 1.68 million b/d in fourth-quarter 2007; demand was slightly lower in first-quarter 2008 at an average of 1.61 million b/d. Demand for LPG feedstocks (ethane, propane, and normal butane) averaged 1.16 million b/d in fourth-quarter 2007 and fell to 1.13 million b/d in first-quarter 2008.

Due to the decline in LPG demand, ethylene producers cracked a somewhat heavier feed slate in fourth-quarter 2007, but the feed slate shifted lighter during first-quarter 2008. Specifically, LPG feeds accounted for 70% of total fresh feed in first-quarter 2008 vs. 69% of fresh feed in fourth-quarter 2007.

Demand for propane and normal butane typically rebound during first quarter. Propane demand, however, remained nearly constant during first-quarter 2008 vs. fourth-quarter 2007 and demand for normal butane was unusually weak.

In contrast, demand for ethane remained robust during fourth-quarter 2007 and first-quarter 2008. Specifically, ethane's share of total fresh feed increased to 50.3% during first-quarter 2008 vs. 49.5% during fourth-quarter 2007 and 47.4% during third-quarter 2007. Demand for ethane set record highs on a volumetric basis in December 2007 (847,000 b/d) and on a share of fresh feed basis in March 2008 (52.3%).

Table 1 shows trends in olefin plants' fresh feed slates.

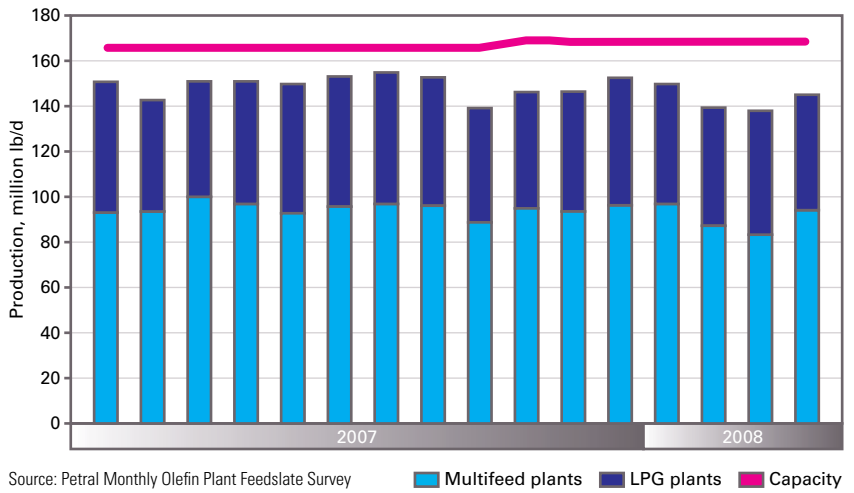
Based on projected ethylene industry operating rates of 85-88% for second and third-quarter 2008, total demand for fresh feedstocks will average 1.55-1.65 million b/d. Total demand for LPG feedstocks will average 1.15-1.20 million b/d during first-quarter 2008 and will increase to 1.20-1.25 million b/d during second-quarter 2008.

LPG feedstocks will account for 75-78% of total fresh feed during second and third quarters 2008. Demand for ethane will remain strong and ethane's share of fresh feed will average 50-53% during second and third quarters 2008.

Fig. 1 shows historic trends for ethylene feed slates.

US ETHYLENE PRODUCTION

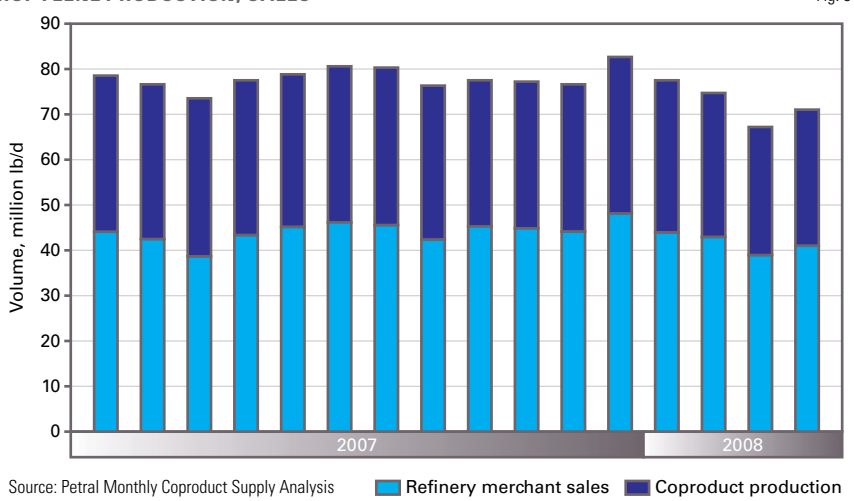
Fig. 2



Source: Petral Monthly Olefin Plant Feedslate Survey

PROPYLENE PRODUCTION, SALES

Fig. 3



Source: Petral Monthly Coproduct Supply Analysis

Ethylene production

Ethylene production from fresh feed totaled 13.66 billion lb in fourth-quarter 2007 but declined to 12.97 billion lb in first-quarter 2008 (Table 2). Ethylene production from steam crackers during fourth-quarter 2007 was 39 million lb less than in third-quarter 2007 (less than half a day's output).

Production in first-quarter 2008 was 695 million lb less than in fourth-quarter 2007 (about 5 days of production). A series of turnarounds contributed to reduced production in first-quarter 2008, but ethylene producers also reduced operating rates in multifeed crackers due to unfavorable economics for naphthas, condensates, and gas oils.

Production from LPG plants totaled 4.95 billion lb in fourth-quarter 2007 and 4.85 billion lb in first-quarter 2008. Production in first-quarter 2008 was 100 million lb less than in fourth-

ETHYLENE FROM US STEAM CRACKERS

Table 2

2007	Production, billion lb: LPG crackers	Multifeed crackers	Total
September	1.50	2.66	4.16
October	1.58	2.94	4.52
November	1.62	2.79	4.40
December	1.75	2.98	4.74
2008			
January	1.65	3.00	4.65
February	1.52	2.53	4.04
March	1.69	2.59	4.28
April	1.53	2.82	4.35

Source: Petral Monthly Ethylene Feedslate Survey

PROPYLENE FROM US STEAM CRACKERS

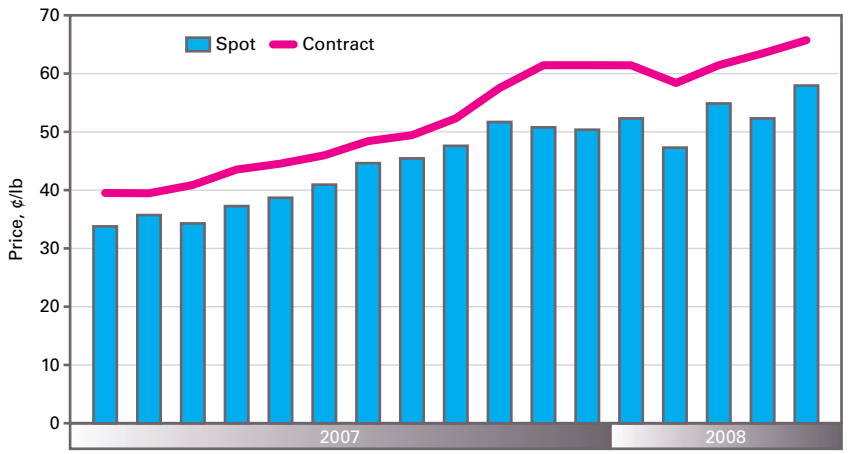
Table 3

2007	Production, million lb: LPG feeds	Naphtha, gas oil feeds	Estimated production
September	351.1	627.7	978.8
October	339.2	629.2	1,028.4
November	339.5	646.4	985.9
December	368.3	709.5	1,077.8
2008			
January	339.0	719.9	1,058.9
February	327.4	574.4	901.8
March	373.2	516.4	889.6
April	413.2	486.0	899.2

Source: Petral Monthly Propylene Supply Analysis

ETHYLENE PRICES

Fig. 4



Source: Petral market research

quarter 2007 (about 2 days of production).

Production from multifeed crackers totaled 8.71 billion lb in fourth-quarter 2007 but declined to 8.11 billion lb in first-quarter 2008. Production from multifeed crackers during fourth-quarter 2007 was 590-600 million lb less than during fourth-quarter 2007 (about 6 days of production).

Operating rates for LPG crackers averaged 91% of nameplate capacity (21.6 billion lb/year) during fourth-quarter 2007 and averaged 90% during first-quarter 2008. Multifeed crackers operated at 87% of nameplate capacity (39.2 billion lb/year) during fourth-quarter 2007 and at 81% during first-quarter 2008.

Operating rates for industry overall averaged 88.0% during fourth-quarter 2007 but slipped to 84.6% during first-quarter 2008. Multifeed crackers accounted for 75-80% of all capacity that experienced downtime during first-quarter 2008 for reasons other than turnarounds. Production curtailments in multifeed crackers were reasonable in response to the deteriorating profit margins for naphthas, condensates, and gas oils.

Fig. 2 shows trends in ethylene production.

US propylene production

Propylene from steam crackers totaled 3.08 billion lb in fourth-quarter 2007, which was 55 million lb less than in third-quarter 2007 (less 2 days of production). Coproduct propylene production during fourth-quarter 2007, however, was 122 million pounds less than year-earlier volumes (4 days of production). Propylene production declined again in first-quarter 2008 and totaled only 2.85 billion lb—233 million lb less than in fourth-quarter 2007 (about 7 days of production).

Propylene production from LPG feeds totaled 1.10 billion lb in fourth-quarter 2007 and was nearly 300 million lb less than production in third-quarter 2007. Propylene from LPG feeds was also 180 million lb less than year-earlier volumes. Propylene production from LPG feeds declined in first-quarter 2008 and totaled only 1.04 billion lb—59 million lb less than in fourth-quarter 2007.

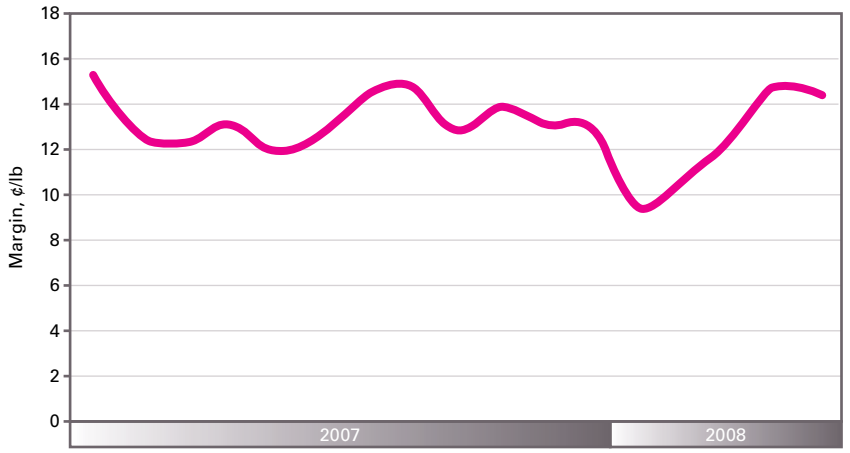
During fourth-quarter 2007 and first-quarter 2008, ethane cracking remained strong while propane and normal-butane cracking remained at seasonal minimum levels. The sustained strength in feedstock demand for ethane was the most significant factor resulting in the 20% decline in coproduct propylene yields from LPG feeds during fourth-quarter 2007.

Propylene production from naphthas, condensates, and gas oils was 1.99 billion lb in fourth-quarter 2007, which was 233 million lb more than during third-quarter 2007. Coproduct yields of propylene from heavy feeds declined to 1.81 billion lb during first-quarter 2008, which was 175 million pounds less than fourth-quarter 2007.

Ethylene producers will continue to maximize their use of ethane during second and third quarters 2008. Furthermore, multifeed crackers will likely continue to operate at reduced rates. Coproduct yields of propylene will therefore continue to average 0.85-0.95 billion lb/month.

ETHYLENE PROFIT MARGIN

Fig. 5



Source: Petral analysis

US REFINERY MERCHANT PROPYLENE

Table 4

	Sales, million lb			
2007	**Texas**	**Louisiana**	**Other states**	**Total**
September	481.5	432.8	357.7	1,272.0
October	444.1	483.5	324.8	1,252.5
November	484.6	498.0	346.6	1,329.1
December	575.6	491.6	318.5	1,385.6
2008				
January	578.1	470.7	312.1	1,360.9
February	474.9	418.7	307.3	1,201.0
March	436.0	476.0	288.1	1,200.

Source: EIA Petroleum Supply Monthly

Table 3 shows trends in coproduct propylene production from LPG and multifeed plants.

Refinery propylene supply

Normally, refinery propylene production reaches an annual peak during third quarter and declines in fourth and first quarters. Refinery-grade propylene production during third-quarter 2007, however, was less than expected levels and averaged 41.4 million lb/day.

Refinery propylene sales increased to 3.97 billion lb in fourth-quarter 2007 and averaged 43.1 million lb/day (Table 4). Production was 156 million lb more than third-quarter 2007 (about 4 days of production), but was 229 million pounds less than year-earlier volumes (about 5 days of production).

As expected, refinery propylene sales declined during first-quarter 2008 and totaled 3.76 billion lb, which was 41.8 million lb/day. Production in first-quarter 2008 was 200 million lb less than in fourth-quarter 2007, but was only 54 million lb less than year-earlier volumes. Refinery propylene sales in first-quarter 2008 were about 100 million lb more than discussed in an earlier article (OGJ, Feb. 4, 2008, p. 56).

Domestic propylene production was 7.01 billion lb in fourth-quarter 2007 and was 101 million lb more than in third-quarter 2007. Domestic production declined in first-quarter 2008 and totaled only 6.56 billion lb, which was 347 million lb less than year-earlier volumes. The year-to-year decline in domestic propylene production began in second-quarter 2007 and persisted for 4 consecutive quarters.

Fig. 3 shows trends in coproduct and refinery merchant propylene sales.

Ethylene economics, prices

Feedstock prices, coproduct values, and ethylene plant yields determine ethylene production costs. Petral Worldwide maintains direct contact with the olefin industry and track historic trends in spot prices for ethylene and propylene. We use a variety of sources to track trends in feedstock prices.

Some ethylene plants have the necessary process units to convert all coproducts into high-purity streams. Some ethylene plants, however, do not have the capability to upgrade mixed or crude streams of various coproducts and sell some or all their coproducts at discounted prices. We evaluate ethylene production costs in this article based on all coproducts valued at spot prices.

Ethylene production costs

Production costs for ethylene in the Houston Ship Channel (based on full spot prices for all coproducts) declined to 41-42¢/lb in March 2008 for ethane and normal butane from 47-48¢/lb in January 2008. Production costs for propane also declined during January-March 2008 (44¢/lb in March vs. 48¢/lb in January). Production costs for natural gasoline, however, increased 3.5-4.0¢/lb and averaged 55-56¢/lb in March vs. 51-52¢/lb in January.

Production costs for natural gasoline were only 4¢/lb more than ethane in January but were 13-14¢/lb higher than ethane in March. In response to these economic incentives, ethylene producers maintained an ethane-rich feed slate during first-quarter 2008.

Ethane's share of fresh feed to LPG crackers was a record high 81% during first-quarter 2008. Similarly, ethane's share of fresh feed to multifeed crackers was a record high 33.9% for first-quarter 2008 and reached 35.4% in March.

During the first few days of February, spot prices for ethane collapsed. During the first 2 weeks of January, ethane prices in Mont Belvieu averaged 114-115¢/gal. By the end of the first week of February, purity ethane prices

fell to 91-92¢/gal, a level 20% lower than in early January.

Spot prices for propane and natural gasoline declined 15.8% and 14.3%, respectively, during mid-January through mid-February. More significantly, however, spot prices for natural gasoline increased 15.5¢/gal (10.8%) during mid-February through mid-March; purity ethane prices were steady at 94-96¢/gal.

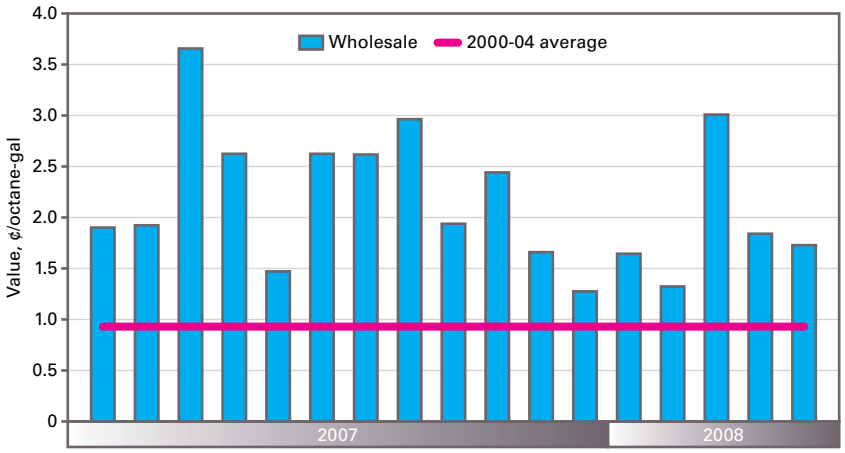
Gas-plant ethane production in the Rocky Mountains began to increase in September-October 2007 and many feedstock buyers and gas processors anticipated additional production growth. Furthermore, a series of ethylene plants started turnarounds in February and March 2008.

The anticipation of greater ethane production and the temporary but minor slump in demand tipped the ethane market into a modest surplus during February and March. Finally, feedstock buyers and ethane producers seemed remarkably reluctant to accumulate any inventory during the various plant turnarounds. The shift in perceptions regarding ethane supply and pricing had an unexpected bearish effect on ethane prices during February through mid-May.

Table 5 shows trends in ethylene production costs.

US GULF COAST OCTANE VALUES

Fig. 6



Source: Petral analysis

ETHYLENE COSTS, HOUSTON SHIP CHANNEL

Table 5

	Variable, direct fixed cash costs, ¢/lb				
2007	**Purity ethane**	**Purity propane**	**Normal butane**	**Natural gasoline**	**Industry composite**
September	38.3	41.5	37.5	40.3	39.3
October	42.6	46.2	39.9	44.2	43.5
November	45.1	51.7	46.0	51.3	47.1
December	45.6	49.8	45.5	52.7	47.3
2008					
January	47.9	48.6	46.9	51.7	48.3
February	41.4	45.0	41.4	51.9	43.3
March	42.0	44.2	41.1	55.5	43.3
April	40.6	45.7	37.6	58.3	42.7
May	40.8	48.2	42.0	61.3	44.0

Source: Petral production cost analysis and forecasts

Ethylene prices, profit margins

Contract prices for ethylene averaged 60.2¢/lb in fourth-quarter 2007, which were 10¢/lb higher than in third-quarter 2007.

During fourth-quarter 2007, contract prices increased to 57.5¢/lb in October and 61.5¢/lb in November and December, up from 52.5¢/lb in September. Contract prices were nearly unchanged in first-quarter 2008 and averaged 60.5¢/lb.

Margins based on purity ethane increased in fourth-quarter 2007 and averaged 15.7¢/lb, which were 1¢/lb more than in third quarter. Margins based on natural gasoline, however, declined in fourth-quarter 2007 and averaged 10.8¢/lb or 3.1¢/lb less than in third quarter.

Margins based on purity ethane were slightly lower in first-quarter 2008 and averaged 14.5¢/lb, which were 1.2¢/lb less than in fourth-quarter 2007. Margins based on natural gasoline, however, collapsed in first-quarter 2008 and averaged 3.9¢/lb—6.9¢/lb less than in fourth-quarter 2007.

During fourth-quarter 2007, spot prices for ethylene fluctuated within a tight range of 50-52¢/lb and averaged 51.2¢/lb, which was 5.2¢/lb more than in third quarter and 12.3¢/lb more than in second-quarter 2007. The increase in spot ethylene prices during fourth-quarter 2007, however, did not keep pace with rising variable production costs. Instead, margins based on spot prices and variable production costs narrowed to 8-13¢/lb during the fourth quarter for purity ethane.

Margins based on natural gasoline and similar light naphthas collapsed to 3¢/lb in December from 12¢/lb in October 2007.

Spot prices for ethylene averaged 51.6¢/lb in first-quarter 2008, but fluctuated within a range of 47-55¢/lb. Margins based on variable production costs for ethane averaged 11¢/lb in first-quarter 2008 and jumped to 16-17¢/lb in March, up from 8-10¢/lb in January and February.

The squeeze on margins for light naphthas and natural gasoline got measurably worse during first-quarter 2008. Margins were slightly below breakeven in January, but these feedstocks generated losses of 2-6¢/lb in February and March.

Figs. 4 and 5 show historic trends in ethylene prices (spot and net transac-

tion prices) and profit margins based on composite production costs.

Octane values, propylene prices

We determine octane's incremental value using the differential between unleaded premium and unleaded regular (ULR) gasoline prices divided by the difference in octane (87 octane for ULR gasoline and 93 octane for unleaded premium gasoline).

Octane values are a primary economic influence on spot prices for refinery-grade propylene and toluene. Trends in spot prices for these two products tend to influence prices for other coproducts.

Octane values rebounded during first-quarter 2008 and averaged 1.99¢/octane-gal vs. 1.80¢/octane-gal in fourth-quarter 2007. Octane values jumped to 3.0¢/octane-gal in March, up from 1.33¢/octane-gal in February. Octane values, however, slipped to less than 2¢/octane-gal during April and May and were 1.55-1.60¢/octane-gal during second-quarter 2008.

The rebound in octane values and an increase in ULR prices helped boost spot prices for alkylate by more than 20¢/gal during January-March 2008.

Fig. 6 shows historic trends in incremental octane values on the US Gulf Coast.

Refinery, polymer-grade $C^{3=}$

Prices for all grades of propylene move in tandem with each other, and differentials between grades are generally constant within a narrow range. The premium for polymer-grade propylene covers operating costs and profit margins for the various merchant propane-propylene splitters in Texas and Louisiana.

Spot prices for refinery-grade propylene averaged 54.2¢/lb during first-quarter 2008 or 0.5¢/lb less than the average for fourth-quarter 2007. Although spot prices for refinery-grade propylene were essentially flat, ULR and alkylate spot prices increased 8.6% during first-quarter 2008.

Spot prices for refinery-grade propylene jumped to 62.4¢/lb in April and 66.4¢/lb in May. Spot prices for second-quarter 2008 were an estimated 66.3¢/lb.

Contract prices for polymer-grade propylene averaged 61.2¢/lb in first-quarter 2008 and 69.7¢/lb in second quarter 2008. Pricing differentials between contract polymer-grade propylene and spot refinery-grade propylene widened to 7¢/lb during first-quarter 2008 but narrowed to 3.4¢/lb in second-quarter 2008.

In response to building bullish pressures and persistent weakness in domestic propylene production, spot prices for refinery-grade propylene jumped to an average of 66.4¢/lb in May 2008 and increased to more than 70¢/lb in early June.

Summer, fall 2008 outlook

US Energy Information Administration statistics indicate that global crude production declined to an average of 73.3 million b/d in 2007 from an average of 73.8 million b/d in 2005.

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2005	2006	2007	Mar. 2007	Feb. 2008	Mar. 2008
Pumps, compressors, etc.	222.5	777.3	1,685.5	1,758.2	1,844.4	1,833.3	1,910.8	1,918.3
Electrical machinery	189.5	394.7	513.6	520.2	517.3	516.8	513.2	515.0
Internal-comb. engines	183.4	512.6	931.1	959.7	974.6	969.5	986.5	986.5
Instruments	214.8	587.3	1,108.0	1,166.0	1,267.9	1,251.5	1,305.2	1,328.0
Heat exchangers	183.6	618.7	1,072.3	1,162.7	1,342.2	1,374.7	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	1,062.1	1,113.3	1,189.3	1,189.2	1,218.1	1,224.5
Materials component	205.9	629.2	1,179.8	1,273.5	1,364.8	1,388.7	1,431.4	1,466.1
Labor component	258.8	951.9	2,411.6	2,497.8	2,601.4	2,559.6	2,663.0	2,664.1
Refinery (Inflation) Index	237.6	822.8	1,918.8	2,008.1	2,106.7	2,091.2	2,170.4	2,184.9

Refinery operating (1956 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2005	2006	2007	Mar. 2007	Feb. 2008	Mar. 2008
Fuel cost	100.9	810.5	1,360.2	1,569.0	1,530.7	1,704.0	1,819.2	2,019.5
Labor cost	93.9	200.5	201.9	204.2	215.8	219.7	214.7	221.8
Wages	123.9	439.9	1,007.4	1,015.4	1,042.8	1,046.9	997.8	1,023.8
Productivity	131.8	226.3	501.1	497.5	483.4	476.5	464.8	461.6
Invest., maint., etc.	121.7	324.8	716.0	743.7	777.4	771.7	800.9	806.2
Chemical costs	96.7	229.2	310.5	365.4	385.9	370.0	423.7	431.2
Operating indexes								
Refinery	103.7	312.7	542.1	579.0	596.5	609.7	635.8	659.6
*Process units**	103.6	457.5	787.2	870.7	872.6	932.4	981.4	1,055.5

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, Journal Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

Our tabulation of global oil production includes lease condensate but excludes NGLs, which are commonly included in global petroleum production statistics.

Global crude production has not declined on a year-to-year average basis since 1980-84. Furthermore, global demand declined in response to a surge in oil prices after the Iranian revolution and forced producers to curtail global crude production.

Our price forecasts for ethylene feedstocks, production costs, and ethylene and propylene prices are based on the view that crude prices will remain in a strong bullish trend. Price forecasts published in fourth-quarter 2007 were bullish, but prices exceeded our bullish expectations. Forecasts for West Texas Intermediate (WTI) crude prices of $150/bbl, $175/bbl, and even $200/bbl before yearend 2008 are now almost commonplace.

Our forecasts for ethylene production costs for second and third quarters 2008 are based on WTI prices of $125-150/bbl. Although there is increasing evidence that U.S. gasoline demand has begun to decline, demand for refined products in the developing economics continues to grow. Global competition for stagnant crude supply will remain a bullish factor for crude and petrochemical feedstock prices this year.

ULR-WTI pricing differentials were below expectations during first-quarter 2008 and the strong bounce forecast for April and May fizzled. Furthermore, slumping demand for gasoline will keep bearish pressure on ULR-WTI differentials during second and third quarters.

Rising crude prices, however, will push ULR prices on the US Gulf Coast to $3.1-3.2/gal in second-quarter 2008 and $3.3-3.5/gal in third-quarter 2008. These forecasts set the economic basis for feedstock prices including light naphthas and propane.

Spot prices for purity ethane in Mont Belvieu rebounded in late May and early June and have a significant potential to increase another 20-30¢/gal during third-quarter 2008.

Ethylene production costs (full cash costs) will be about 55-60¢/lb for purity ethane, 64-66¢/lb for propane, and 72-76¢/lb for natural gasoline in third-quarter 2008. The projected increase in production costs will push both spot and contract ethylene prices higher during third-quarter 2008.

By early June, spot ethylene prices had already reached 60¢/lb. Spot prices for ethylene will increase to 64-68¢/lb by September. Contract prices will average 72¢/lb for third-quarter 2008 and will increase to 74-75¢/lb in September. ✦

The author

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How indexes have changed

Gary Farrar
Contributing Editor

Nelson-Farrar indexes for finished steels changed drastically during 2004-07. Generally speaking, the alloy steels changed less than carbon steel products.

Alloy bars started the period with an index value of 874.8 and peaked at 1,689.3. Alloy sheets were at an index value of 563.7 in early 2004, and at 1,084.9 in early 2007.

Index for cold-rolled sheets was 1,083.9 during first-quarter 2004, and was 2,086.6 during first-quarter 2007. During the same 4-year period, structural plates started at an index of 1,209.0 and hit a high of 2,019.2 in early 2007.

Composite index for steel products were as high as 1,689.3 during second-quarter 2007, up from 1,069.6 in first-quarter 2004. The composite category includes all steel-mill products. This analysis shows a large increase in the cost of finished steels during 2004-07. ✦

INDEXES FOR FINISHED STEELS

Quarter	Composite	Alloy bars	Cold-rolled sheets	Alloy sheets	Structural plates	Welded carbon tubing
2004						
1st	1,069.6	874.8	1,083.9	563.7	1,209.0	1,459.4
2nd	1,264.3	1,000.0	1,277.3	664.4	1,471.1	1,877.9
3rd	1,406.0	1,131.8	1,375.8	715.7	1,624.4	2,146.9
4th	1,462.7	1,193.8	1,376.8	716.1	1,670.0	2,215.9
Year	**1,300.6**	**1,050.1**	**1,278.4**	**665.0**	**1,493.7**	**1,925.0**
2005						
1st	1,493.7	1,190.0	1,492.6	774.8	1,698.0	2,285.8
2nd	1,419.3	1,155.6	1,489.0	774.4	1,673.1	2,270.5
3rd	1,306.0	1,063.9	1,418.7	738.0	1,582.0	2,203.4
4th	1,417.5	1,177.6	1,449.7	753.8	1,664.9	2,227.4
Year	**1,409.1**	**1,146.8**	**1,462.5**	**760.3**	**1,654.5**	**2,246.8**
2006						
1st	1,421.9	1,189.1	1,407.8	731.9	1,674.2	2,256.1
2nd	1,480.4	1,205.3	1,487.1	773.5	1,728.0	2,302.1
3rd	1,616.7	1,641.8	1,764.5	917.6	1,823.4	2,370.1
4th	1,591.0	1,211.0	1,974.3	1,026.7	1,841.0	2,420.8
Year	**1,527.5**	**1,311.8**	**1,658.4**	**862.4**	**1,766.6**	**2,337.3**
2007						
1st	1,604.3	1,212.0	2,086.6	1,084.9	1,829.6	2,341.3
2nd	1,689.3	1,266.4	2,075.6	1,079.2	2,019.2	2,328.9
3rd	1,599.0	1,233.9	1,731.7	900.5	1,986.0	2,336.5
4th	1,587.5	1,246.4	1,772.7	922.0	1,946.6	2,311.6
Year	**1,620.0**	**1,239.7**	**1,916.6**	**996.7**	**1,945.3**	**2,329.6**

ITEMIZED REFINING COST INDEXES

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil and Gas Journal.

Operating cost (based on 1956 = 100.0):	1954	1972	2005	2006	2007	Feb. 2008	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	771.3	850.2	897.3	892.1	Code 0543	No. 13, May 19, 1958
Fuel, refinery price	85.5	152.0	1,288.9	1,523.6	1,497.0	1,731.3	OGJ	No. 4, Mar. 17, 1958
Gulf cargoes	85.0	130.4	1,635.4	2,023.9	1,968.0	2,378.7	OGJ	No. 4, Mar. 17, 1958
NY barges	82.6	169.6	1,539.6	1,837.5	2,066.9	2,673.7	OGJ	No. 4, Mar. 17, 1958
Chicago low sulfur	—	—	1,478.4	1,765.8	2,046.7	2,603.4	OGJ	July 7, 1975
Western US	84.3	168.1	1,941.5	2,358.1	2,704.2	3,317.2	OGJ	No. 4, Mar. 17, 1958
Central US	60.2	128.1	1,274.0	1,765.9	1,886.9	1,973.8	OGJ	No. 4, Mar. 17, 1958
Natural gas at wellhead	83.5	190.3	7,010.6	6,306.5	6,118.7	6,996.4	Code 531-10-1	No. 4, Mar. 17, 1958
Inorganic chemicals	96.0	123.1	562.9	686.8	743.6	834.6	Code 613	Oct. 5, 1964
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 3, 1963
Acid, sulfuric	100.0	140.7	397.4	397.4	397.4	397.4	Code 613-0281	No. 94, May 15, 1961
Platinum	92.9	121.1	819.3	1,344.5	1,557.8	1,593.1	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	357.3	452.4	490.1	549.9	Code 613-01-03	No. 58, Oct. 12, 1959
Sodium hydroxide	95.5	136.2	529.6	620.1	671.6	753.7	Code 613-01-04	No. 94, May 15, 1961
Sodium phosphate	97.4	107.0	733.7	733.7	733.7	733.7	Code 613-0267	No. 58, Oct. 12, 1959
Organic chemicals	100.0	87.4	666.5	764.5	799.9	878.9	Code 614	Oct. 5, 1964
Furfural	94.5	137.5	961.9	1,103.1	1,174.1	1,268.3	Chemical Marketing Reporter	No. 58, Oct. 12, 1959
MEK, tank-car lots	82.6	87.5	625.0	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	411.3	374.9	413.0	416.9	Code 614-0241	No. 58, Oct. 12, 1959

ITEMIZED REFINING COST INDEXES

Operating cost (based on 1956 = 100.0):	1954	1972	2005	2006	2007	Feb. 2008	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages & benefits	88.7	210.0	1,007.0	1,015.4	1,042.8	997.8	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	501.1	497.5	483.4	464.8	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,170.8	2,240.7	2,344.4	2,403.9	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	2,863.5	2,971.7	3,083.0	3,144.2	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	2,411.6	2,497.8	2,601.4	2,663.0	OGJ	May 15, 1967
Equipment or materials (1946 = 100):								
Bubble tray	161.4	324.4	1,409.4	1,484.0	1,561.4	1,596.7	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	886.4	969.6	1,003.2	1,018.3	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,301.7	1,408.6	1,429.1	1,420.9	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	1,441.1	1,540.5	1,616.2	1,679.0	Code 135	May 30, 1955
Castings, iron	188.1	274.9	1,290.0	1,351.3	1,414.3	1,466.9	Code 1015	Apr. 1, 1963
Clay products (structural, etc.)	159.1	342.0	893.8	951.6	963.2	970.1	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	985.5	1,092.0	1,172.2	1,219.8	Code 132	No. 22, March 17, 1949
Concrete products	138.5	199.6	841.3	921.1	961.6	978.8	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	513.6	520.2	517.3	513.2	Code 117	May 2, 1955
Motors and generators	157.7	211.0	839.2	880.3	917.1	943.5	Code 1173	May 2, 1955
Switchgear	171.2	271.0	1,090.0	1,147.3	1,212.2	1,246.9	Code 1175	May 2, 1955
Transformers	161.9	149.3	537.1	612.5	696.9	732.2	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	931.1	959.7	974.6	986.5	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	1,072.3	1,162.7	1,342.2	1,374.7	Manufacturer	Mar. 16, 1964
Copper base	190.7	266.7	992.1	1,059.4	1,201.8	1,241.9	Manufacturer	Mar. 16, 1964
Carbon steel	156.8	281.9	1,080.2	1,162.1	1,344.7	1,396.5	Manufacturer	Mar. 16, 1964
Stainless steel (304)	—	—	1,119.3	1,174.8	1,322.1	1,365.0	Manufacturer	July 1, 1991
Fractionating towers	151.0	278.5	1,157.2	1,207.2	1,274.3	1,308.2	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	1,722.1	1,792.5	1,830.6	1,874.4	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,108.0	1,166.0	1,267.9	1,305.2	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	2,228.6	2,257.4	2,258.6	2,209.8	Manufacturer	July 4, 1988, p. 193
Lumber (composite):	197.8	353.4	1,359.6	1,309.8	1,204.1	1,124.0	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	998.6	984.3	846.4	757.7	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,057.9	1,948.1	1,744.3	1,561.5	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,163.6	1,213.7	1,271.8	1,303.7	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,499.2	1,559.7	1,594.4	1,618.1	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,454.8	1,599.1	1,715.8	1,778.8	Code 1191	Oct. 10, 1955
Paints—prepared	159.0	231.8	975.3	1,040.8	1,078.5	1,118.5	Code 621	May 16, 1955
Pipe								
Gray iron pressure	195.0	346.9	2,580.2	2,687.9	2,730.8	2,706.3	Code 1015-0239	Jan. 3, 1983
Standard carbon	182.7	319.9	2,217.3	2,306.9	2,299.2	2,476.8	Code 1017-0611	Jan. 3, 1983
Pumps, compressors, etc.	166.5	337.5	1,685.5	1,758.2	1,844.4	1,910.8	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,409.1	1,527.5	1,620.0	1,650.4	Code 1017	Jan. 3, 1983
Alloy bars	198.7	349.4	1,146.8	1,311.8	1,239.7	1,332.3	Code 1017-0831	Apr. 1, 1963
Cold-rolled sheets	187.0	365.5	1,462.5	1,658.4	1,916.6	1,688.8	Code 1017-0711	Jan. 3, 1983
Alloy sheets	177.0	225.9	760.3	862.4	996.7	878.2	Code 1017-0733	Jan. 3, 1983
Stainless strip	169.0	221.2	811.6	920.7	1,064.2	937.5	Code 1017-0755	Jan. 3, 1983
Structural carbon, plates	193.4	386.7	1,654.5	1,766.6	1,945.3	2,054.4	Code 1017-0400	Jan. 3, 1983
Welded carbon tubing	180.0	265.5	2,246.8	2,337.3	2,329.6	2,509.9	Code 1017-0622	Jan. 3, 1983
Tanks and pressure vessels	147.3	246.4	974.4	1,014.3	1,076.4	1,108.5	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	540.5	579.9	612.0	624.2	Computed	Oct. 1, 1962
Valves and fittings	197.0	350.9	1,738.2	1,839.6	1,943.9	1,994.4	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	1,918.8	2,008.1	2,106.7	2,170.4	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	542.1	579.0	596.5	635.8	OGJ	No. 2, Mar. 3, 1958
Nelson-Farrar Refinery Process								
(1956)	88.4	147.0	787.2	870.7	872.6	981.4	OGJ	No. 2, Mar. 3, 1958

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

US NATURAL GAS—1

Increased Texas-to-Southeast deliveries affect price bases

Porter Bennett
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The Texas-Gulf Coast natural gas pipeline buildout during the last year has caused price and flow changes offering a glimpse into what will likely take place as the construction boom continues. Even as these projects advance, however, the scope of announced storage projects in the region has raised the possibility of a large excess in capacity moving forward.

One of the most important pipeline projects affecting the Southeast-US Gulf region, CenterPoint's Carthage-to-Perryville project, went online in May 2007, adding 1.2 bcfd of capacity between Carthage, Tex., and Delhi, La., near Perryville. Four other new projects entered service in first-quarter 2008. Three projects built by Trunkline, NGPL, and Gulf South increased capacity eastward out of Texas by 2.5 bcfd (OGJ, Apr. 28, 2008, p. 57). A fourth project on the Enbridge Texas pipeline system added upstream transportation from the Bossier Sands area of East Texas to South Texas.

This first part of two articles examines the basis shifts already underway and expected as a result of ongoing pipeline construction in the Texas-Gulf Coast region. The concluding article (next week) will detail planned Southeast US-Gulf Coast storage construction and examine the potential for overbuild.

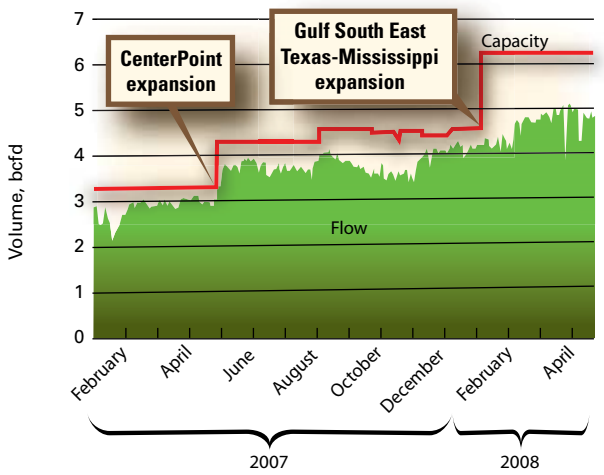
Deliveries increase

Texas-Gulf Coast pipeline projects have led to a large increase in deliveries from Texas into the Southeast US-Gulf Coast region. Imports from Northeast Texas into the area via Carthage-Perryville are up an average of 1.8 bcfd so far in 2008 as compared to the same period in 2007, including a 1-bcfd gain on CenterPoint's CP Line and a 700,000-MMcfd increase on Gulf South's East Texas to Mississippi expansion. Figs. 1 and 2 show the flow and capacity patterns from East Texas to Perryville and South Texas into the Henry Hub via the Houston Ship Channel, respectively.

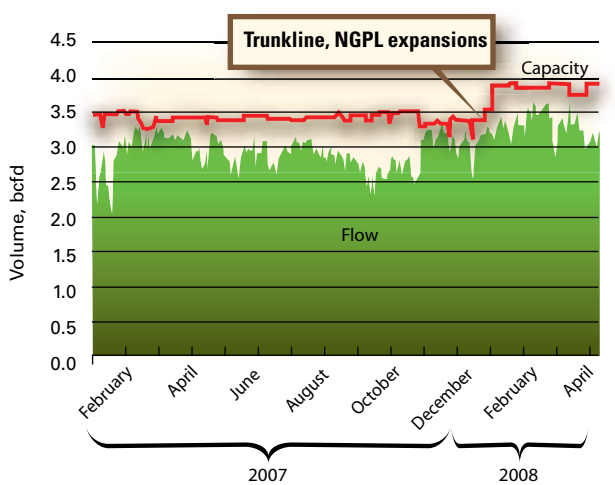
Despite limited capacity to move gas east from Perryville, the pipeline expansion projects have already led to price increases in the Carthage area and other parts of Texas.

Fig. 3 shows the Carthage Hub basis moving from an average of –$0.54/MMbtu in the first 3 months of 2007 to –$0.24/MMbtu for the same period in 2008. Carthage prices at the beginning of April were rapidly closing the

EAST TEXAS FLOWS INTO CARTHAGE-PERRYVILLE Fig. 1

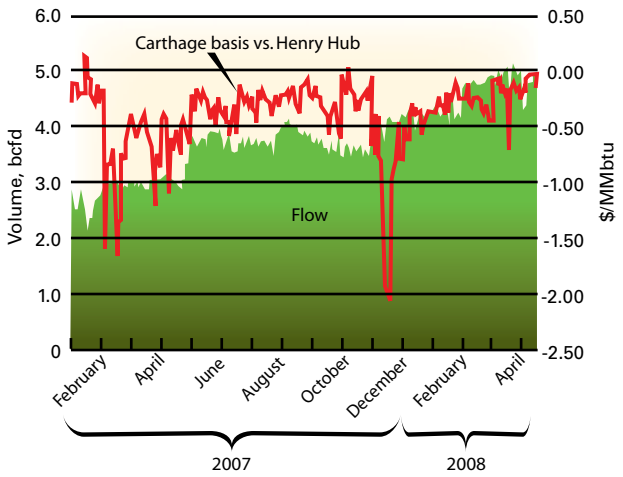


SOUTH TEXAS FLOWS, HOUSTON SHIP CHANNEL-HENRY HUB Fig. 2



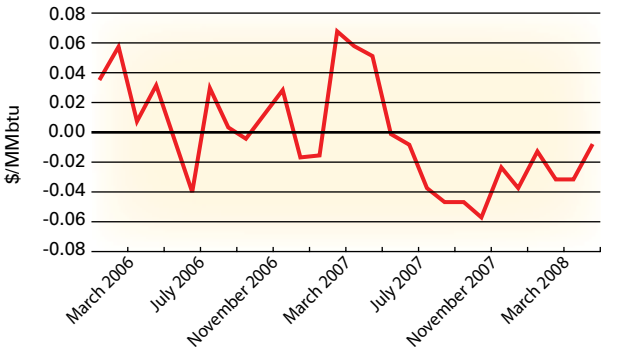
EAST TEXAS FLOWS, CARTHAGE BASIS

Fig. 3



HENRY HUB-PERRYVILLE PRICE DIFFERENTIAL

Fig. 4



gap with Henry Hub and may rise into positive territory compared to the Hub in reaction to new capacity between the Perryville Hub and delivery points at the edge of the Southeast US-Gulf Coast supply bubble.

Houston Ship Channel prices and basis have also gained substantial ground, moving from –$0.49/MMbtu in first quarter 2007 to –$0.30/MMbtu a year later and averaging –$0.15/MMbtu for the first three weeks of April 2008. Carthage and the Houston Ship Channel have also closed the gap with points in the premium Southeast market, including Transco Zone 4. The Houston Ship Channel-Transco Z4 spread has dropped to $0.61/MMbtu on average in first-quarter 2008 compared to $0.84/MMbtu first-quarter 2007.

Flows shift

Since no new capacity east of Perryville has been placed into service yet, access to premium Southeast delivery locations, such as Transco Zone 4 and FGT Z3, remains constrained, causing incremental gas flow into Perryville to move primarily along Columbia Gulf.

The subsequent increase in deliveries to Columbia Gulf has led to a decrease in northbound flows out of Henry Hub to Perryville. Columbia Gulf reconfigured its Rayne compressor last year, allowing southbound flows to South Louisiana interconnects to accommodate the increased supply arriving into its system in the Perryville area. The company also reactivated two interconnections with Transco in South Louisiana and boosted capacity at its FGT interconnection in May, allowing more Perryville gas to reach premium market points in South Louisiana by displacement.

Northbound flows from Henry Hub to Perryville on Columbia have declined 700 MMcfd so far in 2008, compared with a year earlier. Although a net northbound flow on Columbia remains, the increased supply in the Perryville area is displacing enough northbound material from South Louisiana to effectively allow more gas to be delivered to South Louisiana interconnects.

Similar flow changes have occurred on Texas Gas and to a lesser degree Trunkline.

In contrast with previous years, when these pipes moved gas through Perryville and into the Midwest and Ohio Valley, they now deliver more gas into interconnects in South Louisiana, providing access to Southeast and Northeast markets. These flow shifts caused the price at Perryville to drop below Henry Hub last year when the Carthage-to-Perryville line went into service and continue to pressure Perryville pricing, which has averaged $0.02/MMbtu less than Henry Hub since January 2008 (Fig. 4), compared with a $0.04 premium to Henry Hub during first-quarter 2007.

Flows on the Gulf South ETX to MS Pipeline expansion have similarly increased supplies into Transco at Holmesville, Miss., and TETCO at Kosciusko, Miss.

Upcoming shift

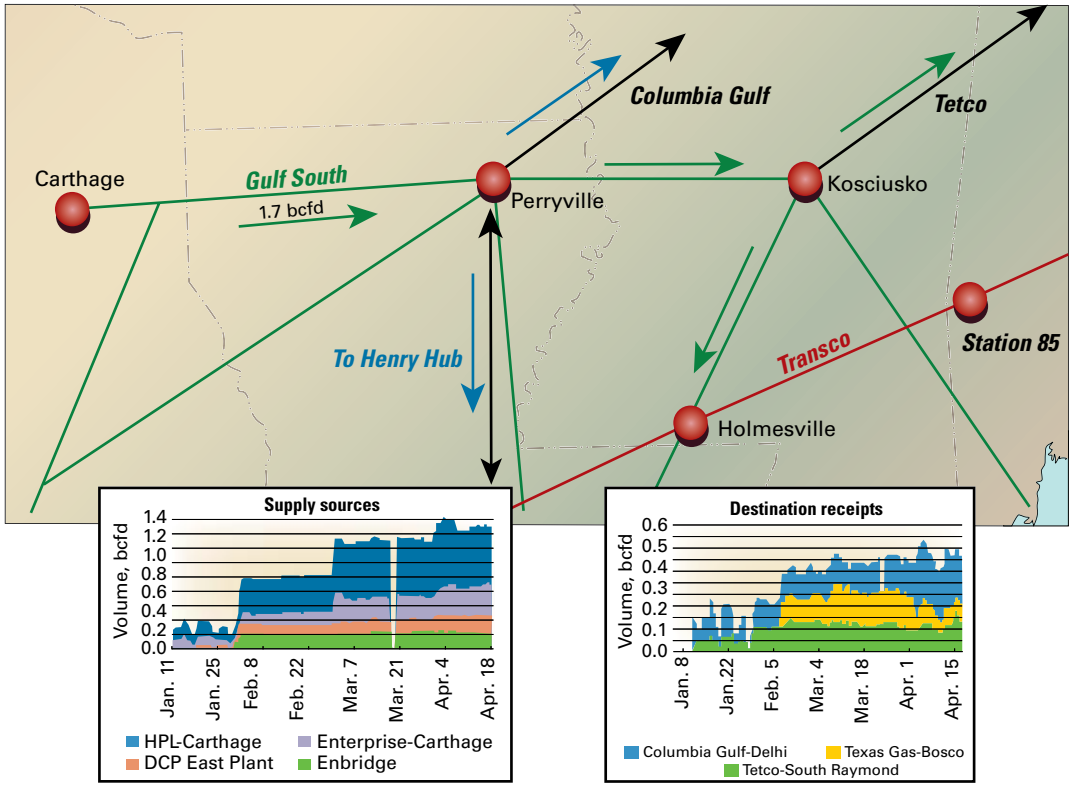
The Gulf South Southeast Gulf expansion added 1.3 bcfd from Harrisville, Miss., into the Transco Zone 4 pool when it entered service May 31, 2008. The Southeast Supply Header will add 1.0 bcfd from Perryville, La., to Gulfstream in second-quarter 2008. These two developments will debottleneck the gas supply corridor between Perryville and the premium Southeast pricing region, shifting both west-east and north-south price differentials.

The remainder of this first part of the article will focus on Gulf South flows during the first 4 months of 2008 and examine a likely scenario of flow and pricing shifts as the Southeast Gulf expansion comes online.

Boardwalk's Gulf South Pipeline is a network-based system that generally transports gas from northeastern and southeastern Texas into North Louisiana on two main pipeline legs. The pipeline also has traditionally transported supply from South Louisiana to the premium Southeast on another pipeline leg. Its latest East Texas-to-Mississippi expansion of 1.7 bcfd will allow Gulf South to flow additional gas from Carthage, Tex., across North

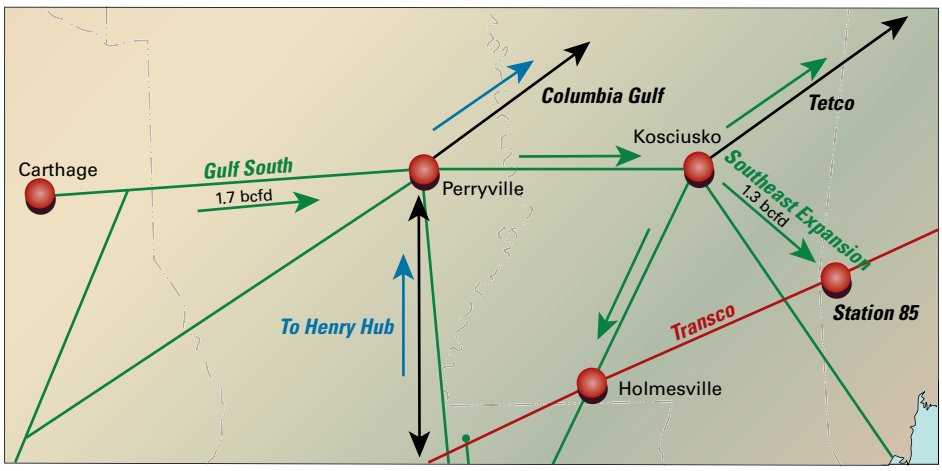
GULF SOUTH EAST TEXAS-MISSISSIPPI EXPANSION

Fig. 5



GULF SOUTH SOUTHEAST GULF EXPANSION

Fig. 6



Louisiana and into Mississippi.

Fig. 5 shows the general flow of gas on Gulf South when the East Texas to Mississippi expansion began service in January 2008. Flows move east from Carthage, Tex., to Perryville, La., and then to Harrisville, Miss., where deliveries occur into TETCO at Kosciusko, Miss., or to Transco at Holmesville, Miss.

Capacity east of Perryville on Gulf South, however, is subject to capacity constraints, moving a portion of the Carthage-to-Perryville flow into other pipelines at Perryville, primarily Columbia Gulf, and displacing gas that previously moved north from Henry Hub to Perryville.

Capacity increased to about 750,000 MMcfd in February and supplies from Energy Transfer's HPL pipeline, Enterprise-Carthage, the DCP East Plant, and Enbridge filled the capacity almost immediately (Fig. 5). Capacity increased again Mar. 1 and Apr. 1 to 1.2 bcfd and 1.7 bcfd, respectively. Although the full 1.7 bcfd capacity is available, flows have yet to reach 1.4 bcfd, primarily because the Tallulah compressor station has not begun service, but is expected to now that the Southwest Expansion has begun operations.

Fig. 5 also shows the increase in volume moving into the expansion points via the Gulf South East Texas-to-Mississippi expansion. A large amount of the increased receipts, however, has been making its way to previously existing downstream delivery points on Gulf South's mainline, particularly Transco Holmesville. Deliveries to Holmesville have increased to average 625 MMcfd as of late April, compared with a 2007 average of only 95 MMcfd. Flows into TETCO at Kosciusko, Miss., also gained more than 200 MMcfd. At the same time, about 450 MMcfd has been

flowing into expansion delivery points, including Columbia Gulf at Delhi, La., Texas Gas at Bosco, La., and TETCO at South Raymond.

Opening the Gulf South Southeast Expansion allows Gulf South to flow 1.3 bcfd directly to Transco Station 85 vs. its previously limited access to the premium Southeast market (Fig. 6). Most of the new capacity will fill immediately, with the following consequences:

- Prices in the Transco Zone 4 pool will come under downward pressure, likely flattening the price differential between Carthage and Transco Station 85.
- Gulf South deliveries into Transco at Holmesville will decline.
- Supply pressures at Perryville will decline, resulting in lower deliveries into Columbia and other pipelines and a reduced incentive to displace gas moving from Henry Hub.
- Perryville prices will likely again move above Henry Hub for two reasons: higher prices at Perryville due to demand for supplies to move via the Southeast Expansion into Transco Zone 4, and downward pricing pressures at Henry Hub due to the displacement of traditional supplies moving into Transco Zone 4 from it and other South Louisiana locations. ✦

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IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	6-13 2008	6-6 2008	6-13 2008	6-6 2008	6-13 2008	6-6 2008	[1]6-15 2007
	1,000 b/d						
Total motor gasoline	1,034	1,195	8	—	1,042	1,195	1,284
Mo. gas. blending comp.	529	644	8	—	537	644	891
Distillate	257	127	—	—	257	127	255
Residual	405	403	—	—	405	403	367
Jet fuel-kerosine	48	78	38	31	86	109	191
Propane-propylene[2]	132	106	2	4	134	110	108
Other	492	743	122	84	614	827	738
Total products	**2,897**	**3,296**	**178**	**119**	**3,075**	**3,415**	**3,834**
Total crude	**9,246**	**8,490**	**1,013**	**1,198**	**10,259**	**9,688**	**10,791**
Total imports	**12,143**	**11,786**	**1,191**	**1,317**	**13,334**	**13,103**	**14,625**

[1]Revised. [2]Data available only for PADDs 1-3.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—JUNE 20, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	9.29	6.74	8.25	6.61	7.49	8.16
Everett	10.52	8.92	10.03	8.95	8.82	10.91
Isle of Grain	11.44	9.18	10.67	9.07	9.76	10.68
Lake Charles	8.75	7.10	8.61	7.33	7.68	9.36
Sodegaura	7.04	9.75	7.28	9.37	8.50	6.14
Zeebrugge	9.26	7.23	8.65	7.13	7.77	8.63

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

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	15,548	56,550	30,627	9,621	34,419	14,981	4,065
PADD 2	64,584	51,443	17,603	7,244	31,159	1,306	15,596
PADD 3	148,742	67,891	32,097	12,511	31,833	17,093	17,896
PADD 4	14,008	6,036	1,738	604	3,239	310	[1]1,119
PADD 5	58,073	26,990	20,604	9,587	12,948	5,259	—
June 13, 2008	**300,955**	**208,910**	**102,669**	**39,657**	**116,598**	**38,949**	**38,676**
June 6, 2008	**302,197**	**210,088**	**104,528**	**39,683**	**113,981**	**39,505**	**38,462**
June 15, 2007[2]	**349,329**	**203,331**	**91,388**	**40,888**	**122,723**	**35,495**	**39,692**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

REFINERY REPORT—JUNE 13, 2008

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,373	1,371	1,962	104	449	110	52
PADD 2	3,388	3,355	2,385	205	1,028	50	214
PADD 3	7,630	7,458	3,004	687	2,152	256	651
PADD 4	555	554	273	25	184	17	[1]158
PADD 5	2,769	2,701	1,341	509	626	121	—
June 13, 2008	**15,715**	**15,439**	**8,965**	**1,530**	**4,439**	**554**	**1,075**
June 6, 2008	**15,593**	**15,319**	**8,974**	**1,493**	**4,475**	**743**	**1,132**
June 15, 2007[2]	**15,298**	**15,022**	**9,328**	**1,420**	**3,991**	**652**	**1,120**
	17,594 operable capacity		**89.3% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*6-20-08	*6-22-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	146.91	90.05	56.85	63.1
Brent crude	133.67	72.18	61.49	85.2
Crack spread	13.24	17.87	–4.63	–25.9
FUTURES MARKET PRICES				
One month				
Product value	150.08	90.88	59.20	65.1
Light sweet crude	134.37	68.83	65.54	95.2
Crack spread	15.71	22.05	–6.34	–28.7
Six month				
Product value	148.23	84.46	63.77	75.5
Light sweet crude	135.85	71.24	64.61	90.7
Crack spread	12.38	13.22	–0.84	–6.4

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

OGJ GASOLINE PRICES

	Price ex tax 6-18-08	Pump price* 6-18-08	Pump price 6-20-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	369.8	414.2	309.4
Baltimore	361.2	403.1	307.4
Boston	364.0	405.9	295.6
Buffalo	361.5	421.1	309.4
Miami	371.7	423.3	311.2
Newark	362.8	395.7	291.4
New York	353.4	413.0	306.8
Norfolk	357.4	395.4	298.3
Philadelphia	363.2	413.9	313.4
Pittsburgh	352.6	403.3	300.4
Wash., DC	375.8	414.2	306.0
PAD I avg.	363.1	409.4	304.5
Chicago	384.8	442.7	337.9
Cleveland	350.4	396.8	288.4
Des Moines	357.5	397.6	314.8
Detroit	354.3	408.7	326.8
Indianapolis	348.3	398.4	317.2
Kansas City	358.6	394.6	314.8
Louisville	365.4	402.3	317.9
Memphis	347.3	387.1	304.7
Milwaukee	359.9	411.2	320.6
Minn.-St. Paul	359.4	399.8	289.8
Oklahoma City	348.7	384.1	300.5
Omaha	351.7	394.0	299.5
St. Louis	356.2	392.2	311.8
Tulsa	346.9	382.3	299.4
Wichita	332.0	375.4	307.3
PAD II avg.	354.8	397.8	310.1
Albuquerque	351.1	387.5	320.7
Birmingham	356.7	395.3	300.0
Dallas-Fort Worth	361.8	400.2	291.5
Houston	353.9	392.3	287.1
Little Rock	353.5	393.7	299.8
New Orleans	358.8	397.2	305.7
San Antonio	351.9	390.3	291.3
PAD III avg.	355.4	393.8	299.4
Cheyenne	358.5	390.9	296.0
Denver	362.1	402.5	318.3
Salt Lake City	357.3	400.2	319.3
PAD IV avg.	359.3	397.9	311.2
Los Angeles	389.9	453.8	322.1
Phoenix	382.8	420.2	308.0
Portland	386.0	429.4	319.3
San Diego	398.8	462.7	340.2
San Francisco	394.2	458.1	338.9
Seattle	383.9	438.3	311.1
PAD V avg.	389.3	443.8	323.3
Week's avg.	**362.3**	**406.7**	**308.8**
May avg.	**329.3**	**372.9**	**307.6**
Apr. avg.	**296.4**	**339.3**	**278.3**
2008 to date	**292.9**	**336.3**	—
2007 to date	**222.0**	**265.6**	—

*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

	6-13-08 ¢/gal		6-13-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	336.50	New York Harbor	382.01
Gulf Coast	329.50	Gulf Coast	379.56
Los Angeles	366.33	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	318.69	ARA	395.54
Singapore	342.52	Singapore	403.38
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	348.50	New York Harbor	251.86
Gulf Coast	347.44	Gulf Coast	251.71
Los Angeles	374.83	Los Angeles	267.61
		ARA	252.34
		Singapore	242.94

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

BAKER HUGHES RIG COUNT

	6-20-08	6-22-07
Alabama	3	7
Alaska	6	7
Arkansas	47	47
California	43	33
Land	43	32
Offshore	0	1
Colorado	113	110
Florida	1	1
Illinois	0	0
Indiana	1	3
Kansas	9	14
Kentucky	11	8
Louisiana	172	180
N. Land	67	59
S. Inland waters	21	23
S. Land	26	32
Offshore	58	66
Maryland	1	0
Michigan	1	1
Mississippi	13	13
Montana	12	15
Nebraska	0	1
New Mexico	80	82
New York	7	5
North Dakota	70	35
Ohio	13	13
Oklahoma	207	195
Pennsylvania	20	13
South Dakota	2	4
Texas	916	825
Offshore	12	13
Inland waters	2	0
Dist. 1	26	22
Dist. 2	29	29
Dist. 3	65	59
Dist. 4	96	90
Dist. 5	178	174
Dist. 6	122	120
Dist. 7B	27	34
Dist. 7C	70	56
Dist. 8	138	110
Dist. 8A	28	28
Dist. 9	39	31
Dist. 10	84	59
Utah	42	39
West Virginia	26	35
Wyoming	76	75
Others—NV-2; OR-1; TN-5; VA-5; WA-1	14	10
Total US	**1,906**	**1,771**
Total Canada	**259**	**205**
Grand total	**2,165**	**1,976**
Oil rigs	384	271
Gas rigs	1,514	1,495
Total offshore	71	81
Total cum. avg. YTD	**1,813**	**1,745**

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	Rig count	6-20-08 Percent footage*	Rig count	6-22-07 Percent footage*
0-2,500	89	3.3	62	6.4
2,501-5,000	147	48.2	112	52.6
5,001-7,500	253	14.6	239	21.3
7,501-10,000	483	3.5	418	2.8
10,001-12,500	476	2.7	452	1.9
12,501-15,000	322	—	273	—
15,001-17,500	127	—	105	0.9
17,501-20,000	73	—	71	—
20,001-over	35	—	38	—
Total	**2,005**	**7.0**	**1,770**	**7.6**
INLAND	32		45	
LAND	1,917		1,654	
OFFSHORE	56		71	

*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]6-20-08	[2]6-22-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	16	19
Alaska	731	724
California	659	667
Colorado	45	39
Florida	6	5
Illinois	26	26
Kansas	94	101
Louisiana	1,363	1,314
Michigan	15	17
Mississippi	52	55
Montana	93	95
New Mexico	165	163
North Dakota	116	120
Oklahoma	174	170
Texas	1,354	1,352
Utah	46	50
Wyoming	147	148
All others	62	75
Total	**5,164**	**5,140**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	6-20-08
Alaska-North Slope 27°	106.81
South Louisiana Sweet	137.50
California-Kern River 13°	120.30
Lost Hills 30°	128.25
Wyoming Sweet	124.62
East Texas Sweet	130.50
West Texas Sour 34°	123.50
West Texas Intermediate	131.00
Oklahoma Sweet	131.00
Texas Upper Gulf Coast	127.50
Michigan Sour	124.00
Kansas Common	130.00
North Dakota Sweet	124.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	6-13-08
United Kingdom-Brent 38°	134.87
Russia-Urals 32°	129.92
Saudi Light 34°	129.05
Dubai Fateh 32°	127.76
Algeria Saharan 44°	135.10
Nigeria-Bonny Light 37°	138.76
Indonesia-Minas 34°	136.88
Venezuela-Tia Juana Light 31°	131.68
Mexico-Isthmus 33°	131.57
OPEC basket	132.97
Total OPEC[2]	130.00
Total non-OPEC[2]	129.33
Total world[2]	129.70
US imports[3]	125.58

[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]

	6-13-08	6-6-08 bcf	6-13-07	Change, %
Producing region	667	660	827	–19.3
Consuming region east	997	959	1,140	–12.5
Consuming region west	279	267	351	–20.5
Total US	**1,943**	**1,886**	**2,318**	**–16.2**
	Mar. 08	**Mar. 07**	**Change, %**	
Total US[2]	**1,247**	**1,603**	**–22.2**	

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

Imports of crude and products

	Districts 1-4 6-20 2008	Districts 1-4 6-13 2008	District 5 6-20 2008	District 5 6-13 2008	Total US 6-20 2008	Total US 6-13 2008	Total US *6-22 2007
	1,000 b/d						
Total motor gasoline	1,162	1,034	—	8	1,162	1,042	1,112
Mo. gas. blending comp.	756	529	—	8	756	537	651
Distillate	107	257	—	—	107	257	214
Residual	335	405	—	—	335	405	377
Jet fuel-kerosine	101	48	13	38	114	86	230
Propane-propylene	79	132	2	2	81	134	160
Other	690	492	51	122	741	614	656
Total products	**3,230**	**2,897**	**66**	**178**	**3,296**	**3,075**	**3,400**
Total crude	**9,058**	**9,246**	**1,193**	**1,013**	**10,251**	**10,259**	**10,501**
Total imports	**12,288**	**12,143**	**1,259**	**1,191**	**13,547**	**13,334**	**13,901**

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

Purvin & Gertz LNG netbacks—June 27, 2008

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	9.29	6.76	8.24	6.62	7.47	8.14
Everett	10.51	8.84	10.01	8.87	9.63	10.90
Isle of Grain	11.57	9.32	10.94	9.17	10.04	10.95
Lake Charles	9.18	7.02	9.03	7.25	7.70	9.64
Sodegaura	7.53	9.74	7.77	9.91	9.01	6.61
Zeebrugge	9.49	7.31	8.89	7.17	8.00	8.87

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

Crude and product stocks

	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	12,880	58,257	31,476	9,705	38,896	15,126	3,917
PADD 2	64,013	49,923	17,018	7,644	31,146	1,290	16,466
PADD 3	151,187	66,720	31,545	12,671	32,551	17,281	18,055
PADD 4	13,798	6,254	1,868	551	3,333	296	[1]1,206
PADD 5	59,880	27,603	20,558	9,929	13,495	5,260	—
June 20, 2008	**301,758**	**208,757**	**102,465**	**40,500**	**119,421**	**39,253**	**39,644**
June 13, 2008	**300,955**	**208,910**	**102,669**	**39,567**	**116,598**	**38,949**	**38,528**
June 22, 2007[2]	**350,891**	**202,582**	**89,982**	**40,124**	**120,448**	**35,772**	**41,954**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—June 20, 2008

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d						
PADD 1	1,401	1,396	2,020	106	539	78	58
PADD 2	3,390	3,357	2,387	220	1,067	48	220
PADD 3	7,481	7,267	2,967	750	2,192	309	649
PADD 4	529	529	292	21	141	12	[1]159
PADD 5	2,787	2,709	1,391	517	649	126	—
June 20, 2008	**15,588**	**15,258**	**9,057**	**1,614**	**4,588**	**573**	**1,086**
June 13, 2008	**15,715**	**15,439**	**8,965**	**1,530**	**4,439**	**554**	**1,075**
June 22, 2007[2]	**15,618**	**15,430**	**9,342**	**1,430**	**3,990**	**628**	**1,109**
	17,594 operable capacity		**88.6% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

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

OGJ crack spread

	*6-27-08	*6-29-07	Change $/bbl	Change, %
SPOT PRICES				
Product value	147..61	89.54	58.08	64.9
Brent crude	137.15	71.53	65.62	91.7
Crack spread	10.46	18.01	–7.54	–41.9
FUTURES MARKET PRICES				
One month				
Product value	151.66	91.25	60.41	66.2
Light sweet crude	137.63	69.23	68.40	98.8
Crack spread	14.03	22.02	–7.98	–36.3
Six month				
Product value	150.61	83.90	66.71	79.5
Light sweet crude	138.47	70.73	67.74	95.8
Crack spread	12.14	13.17	–1.03	–7.8

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

OGJ GASOLINE PRICES

	Price ex tax 6-25-08	Pump price* 6-25-08	Pump price 6-27-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	370.3	414.7	304.4
Baltimore	362.1	404.0	301.1
Boston	365.0	406.9	292.5
Buffalo	362.4	422.0	303.7
Miami	372.4	424.0	305.7
Newark	363.3	396.2	287.7
New York	354.3	413.9	303.5
Norfolk	358.1	396.1	293.4
Philadelphia	363.9	414.6	307.7
Pittsburgh	353.3	404.0	296.1
Wash., DC	376.3	414.7	302.6
PAD I avg.	363.8	410.1	299.8
Chicago	385.6	443.5	329.2
Cleveland	351.1	397.5	282.7
Des Moines	358.4	398.5	304.2
Detroit	355.1	409.5	319.5
Indianapolis	349.0	399.1	313.0
Kansas City	359.5	395.5	303.5
Louisville	365.8	402.7	306.6
Memphis	347.8	387.6	298.8
Milwaukee	360.4	411.7	310.1
Minn.-St. Paul	360.1	400.5	285.9
Oklahoma City	349.2	384.6	288.8
Omaha	352.3	394.6	293.1
St. Louis	356.7	392.7	307.2
Tulsa	347.6	383.0	289.7
Wichita	332.3	375.7	304.4
PAD II avg.	355.4	398.5	302.5
Albuquerque	351.7	388.1	314.8
Birmingham	357.4	396.0	291.9
Dallas-Fort Worth	362.6	401.0	289.1
Houston	354.6	393.0	283.0
Little Rock	354.3	394.5	291.2
New Orleans	359.6	398.0	301.8
San Antonio	352.6	391.0	287.7
PAD III avg.	356.1	394.5	294.2
Cheyenne	361.2	393.6	292.6
Denver	366.0	406.4	313.4
Salt Lake City	359.8	402.7	315.0
PAD IV avg.	362.3	400.9	307.0
Los Angeles	393.3	457.2	315.3
Phoenix	386.6	424.0	303.9
Portland	389.0	432.4	313.0
San Diego	402.3	466.2	328.7
San Francisco	397.4	461.3	326.2
Seattle	387.0	441.4	304.3
PAD V avg.	392.6	447.1	315.2
Week's avg.	**363.5**	**408.0**	**302.6**
June avg.	**360.2**	**404.2**	**309.4**
May avg.	**329.3**	**372.9**	**307.6**
2008 to date	**295.6**	**339.3**	—
2007 to date	**222.0**	**265.6**	—

*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

	6-20-07 ¢/gal		6-20-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	328.94	New York Harbor	375.37
Gulf Coast	330.29	Gulf Coast	371.99
Los Angeles	353.94	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	329.88	ARA	388.89
Singapore	329.19	Singapore	389.33
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	341.94	New York Harbor	247.55
Gulf Coast	337.94	Gulf Coast	249.12
Los Angeles	362.69	Los Angeles	271.38
		ARA	260.78
		Singapore	242.55

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

BAKER HUGHES RIG COUNT

	6-27-08	6-29-07
Alabama	4	7
Alaska	6	6
Arkansas	54	49
California	43	39
Land	43	38
Offshore	0	1
Colorado	113	109
Florida	1	1
Illinois	1	0
Indiana	1	3
Kansas	10	10
Kentucky	11	8
Louisiana	178	177
N. Land	76	57
S. Inland waters	20	22
S. Land	30	34
Offshore	52	64
Maryland	1	0
Michigan	1	1
Mississippi	13	13
Montana	12	19
Nebraska	0	1
New Mexico	80	86
New York	5	5
North Dakota	71	35
Ohio	13	13
Oklahoma	200	192
Pennsylvania	21	13
South Dakota	2	4
Texas	915	827
Offshore	10	12
Inland waters	2	0
Dist. 1	24	21
Dist. 2	30	26
Dist. 3	60	65
Dist. 4	94	94
Dist. 5	185	174
Dist. 6	121	125
Dist. 7B	33	33
Dist. 7C	66	55
Dist. 8	138	102
Dist. 8A	29	26
Dist. 9	41	33
Dist. 10	82	61
Utah	42	39
West Virginia	26	35
Wyoming	76	73
Others—NV-2; OR-1; TN-4; VA-5; WA-1	13	10
Total US	**1,913**	**1,775**
Total Canada	**356**	**231**
Grand total	**2,269**	**2,006**
Oil rigs	375	281
Gas rigs	1,530	1,489
Total offshore	64	78
Total cum. avg. YTD	**1,817**	**1,746**

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	Rig count	6-27-08 Percent footage*	Rig count	6-29-07 Percent footage*
0-2,500	91	3.2	60	6.6
2,501-5,000	147	46.9	117	52.9
5,001-7,500	252	15.8	243	22.2
7,501-10,000	477	3.1	416	3.1
10,001-12,500	481	2.7	459	1.7
12,501-15,000	329	—	259	—
15,001-17,500	132	—	109	0.9
17,501-20,000	83	—	69	—
20,001-over	38	—	36	—
Total	**2,030**	**6.8**	**1,768**	**8.0**
INLAND	33		41	
LAND	1,936		1,657	
OFFSHORE	61		70	

*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]6-27-08	[2]6-29-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	19
Alaska	727	714
California	656	667
Colorado	45	39
Florida	6	5
Illinois	26	26
Kansas	94	100
Louisiana	1,358	1,310
Michigan	14	17
Mississippi	52	56
Montana	92	95
New Mexico	164	163
North Dakota	115	121
Oklahoma	172	170
Texas	1,347	1,346
Utah	46	50
Wyoming	147	149
All others	62	75
Total	**5,138**	**5,122**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	6-27-08
Alaska-North Slope 27°	106.81
South Louisiana Sweet	143.25
California-Kern River 13°	125.95
Lost Hills 30°	133.95
Southwest Wyoming Sweet	130.21
East Texas Sweet	136.25
West Texas Sour 34°	129.25
West Texas Intermediate	136.75
Oklahoma Sweet	136.75
Texas Upper Gulf Coast	133.25
Michigan Sour	129.75
Kansas Common	136.00
North Dakota Sweet	130.00

*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]	6-20-08
United Kingdom-Brent 38°	133.85
Russia-Urals 32°	128.54
Saudi Light 34°	129.66
Dubai Fateh 32°	129.48
Algeria Saharan 44°	134.45
Nigeria-Bonny Light 37°	138.29
Indonesia-Minas 34°	138.44
Venezuela-Tia Juana Light 31°	130.36
Mexico-Isthmus 33°	130.25
OPEC basket	132.99
Total OPEC[2]	130.20
Total non-OPEC[2]	129.26
Total world[2]	129.78
US imports[3]	125.93

[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]

	6-20-08	6-13-08	6-20-07	Change, %
	bcf			
Producing region	685	667	847	–19.1
Consuming region east	1,059	997	1,205	–12.1
Consuming region west	289	279	363	–20.4
Total US	**2,033**	**1,943**	**2,415**	**–15.8**
	Apr. 08	**Apr. 07**	**Change, %**	
Total US[2]	**1,436**	**1,720**	**–16.5**	

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

PACE REFINING MARGINS

	Apr. 2008	May 2008	June 2008	June 2007	2008 vs. 2007 Change	2008 vs. 2007 Change, %
	$/bbl					
US Gulf Coast						
West Texas Sour	14.92	17.15	15.08	21.55	–6.47	–30.0
Composite US Gulf Refinery	14.72	17.29	15.24	12.93	2.31	17.8
Arabian Light	11.28	13.68	13.16	20.09	–6.93	–34.5
Bonny Light	6.88	8.49	5.90	12.12	–6.23	–51.4
US PADD II						
Chicago (WTI)	12.68	16.30	12.41	24.25	–11.84	–48.8
US East Coast						
NY Harbor (Arab Med)	11.47	13.93	14.31	16.09	–1.78	–11.1
East Coast Comp-RFG	14.45	16.50	14.97	10.87	4.10	37.8
US West Coast						
Los Angeles (ANS)	14.88	15.97	18.17	20.46	–2.29	–11.2
NW Europe						
Rotterdam (Brent)	3.73	2.91	1.63	2.54	–0.91	–35.7
Mediterranean						
Italy (Urals)	7.44	7.91	7.09	7.50	–0.41	–5.5
Far East						
Singapore (Dubai)	6.98	12.03	7.13	6.04	1.09	18.1

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Apr. 2008	Mar. 2008	Apr. 2007	Apr. 2008-2007 change	Total YTD 2008	Total YTD 2007	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,837	2,264	1,798	39	9,304	8,922	382
Addition to storage	295	131	154	141	550	602	–52
Exports	82	110	51	31	398	253	145
Canada	41	69	32	9	233	160	73
Mexico	37	37	15	22	152	75	77
LNG	4	4	4	—	13	18	–5
Total demand	**2,214**	**2,505**	**2,003**	**211**	**10,252**	**9,777**	**475**
SUPPLY							
Production (dry gas)	1,755	1,828	1,636	119	7,059	6,476	583
Supplemental gas	5	5	5	—	16	23	–7
Storage withdrawal	106	350	154	–48	1,997	1,945	52
Imports	325	361	388	–63	1,386	1,552	–166
Canada	292	336	280	12	1,274	1,242	32
Mexico	1	1	9	–8	4	27	–23
LNG	32	24	99	–67	108	283	–175
Total supply	**2,191**	**2,544**	**2,183**	**8**	**10,458**	**9,996**	**462**

NATURAL GAS IN UNDERGROUND STORAGE

	Apr. 2008	Mar. 2008	Feb. 2008	Apr. 2007	Change
	bcf				
Base gas	4,223	4,221	4,222	4,246	–23
Working gas	1,436	1,247	1,465	1,720	–284
Total gas	**5,659**	**5,468**	**5,687**	**5,966**	**–307**

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

WORLDWIDE NGL PRODUCTION

	Mar. 2007	Feb. 2008	3 month average Production 2008	3 month average Production 2007	Change vs. previous year Volume,	Change vs. previous year %
	1,000 b/d					
Brazil	86	86	87	86	1	0.9
Canada	696	701	699	724	–25	–3.5
Mexico	367	368	367	411	–44	–10.6
United States	1,847	1,830	1,820	1,714	106	6.2
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	195	202	198	206	–7	3.6
Western Hemisphere	**3,390**	**3,387**	**3,371**	**3,341**	**30**	**0.9**
Norway	301	294	299	301	–2	–0.6
United Kingdom	186	181	183	163	20	12.4
Other Western Europe	10	11	11	10	—	1.4
Western Europe	**497**	**486**	**492**	**474**	**19**	**3.9**
Russia	420	421	421	425	–4	–1.0
Other FSU	150	150	150	160	–10	–6.3
Other Eastern Europe	16	16	16	16	—	0.2
Eastern Europe	**586**	**587**	**587**	**601**	**–14**	**–2.4**
Algeria	353	352	352	340	11	3.3
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	140	129	135	126	9	7.2
Africa	**643**	**631**	**636**	**616**	**20**	**3.3**
Saudi Arabia	1,440	1,440	1,440	1,427	—	—
United Arab Emirates	250	250	250	250	—	—
Other Middle East	880	870	874	870	4	0.4
Middle East	**2,570**	**2,560**	**2,564**	**2,560**	**4**	**0.1**
Australia	57	60	58	73	–15	–20.2
China	180	180	180	180	—	—
India	—	—	—	13	–13	–100.0
Other Asia-Pacific	180	181	181	183	–2	–1.3
Asia-Pacific	**417**	**421**	**419**	**448**	**–30**	**–6.6**
TOTAL WORLD	**8,103**	**8,072**	**8,068**	**8,040**	**29**	**0.4**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Apr. 2008	Mar. 2008	Change	YTD 2008	YTD 2007	Change
	1,000 bbl					
Fuel ethanol						
Production	16,868	17,387	–519	65,098	46,024	19,074
Stocks	11,539	11,391	148	11,539	8,791	2,748
MTBE						
Production	1,613	1,595	18	6,358	7,854	–1,496
Stocks	1,727	1,803	–76	1,727	2,324	–597

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

US HEATING DEGREE-DAYS

	May 2008	May 2007	Normal	2008 % change from normal	Total degree-days July 1 through May 31 2008	2007	Normal	% change from normal
New England	318	245	281	13.2	6,323	6,271	6,579	–3.9
Middle Atlantic	258	159	217	18.9	5,396	5,469	5,904	–8.6
East North Central	273	138	238	14.7	6,369	6,110	6,481	–1.7
West North Central	258	113	208	24,0	6,917	6,324	6,735	2.7
South Atlantic	61	49	61	—	2,530	2,662	2,861	–11.6
East South Central	58	34	76	–23.7	3,389	3,413	3,616	–6.3
West South Central	20	11	17	17.6	2,161	2,249	2,298	–6.0
Mountain	236	175	233	1.3	5,017	4,854	5,150	–2.6
Pacific	191	118	182	4.9	3,254	2,894	3,167	2.7
US average*	**176**	**107**	**159**	**10.7**	**4,332**	**4,227**	**4,508**	**–3.9**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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Requirements: Must have Bachelor's of Engineering degree in Civil Engineering or related field; minimum two years experience working as an onsite drilling or completion engineer; extensive knowledge of specialized engineering skills, including the implementation of new technologies in drilling and well completion, high pressure-high temperature drilling, and directional drilling on mud, foam, and air; and extensive operational experience of at least six months in multiple operating areas, including the Appalachian Basin, the Texas Gulf Coast, and New Zealand. To submit resume, please visit www.eca-eaec.com/hr.htm.

ConocoPhillips Company in Houston, TX seeks a Cost Control Specialist. Qualified applicants will possess a bachelor's degree in engineering plus a minimum of five years of experience in engineering / cost control. To submit resume, please visit www.conocophillips.com/careers. Put job code 004WR on resume.

Smith International, Inc. seeks Drill Bit Optimization System (DBOS) Supervisor to work in Houston, TX. Responsiblef for performance optimization of real time drilling applications for oil, gas, and geothermal wells. Gather & evaluate data for well logging interpretation through real-time drilling optimization software. Support DBOS Group engineers worldwide. Candidate must have Bachelor's in engineering or related field plus experience. Submit resume to Sandy Gillen, HR, Smith International, 16740 Hardy Street, Houston, Tx 77032. Must put job code APDBOS on resume.

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EMPLOYMENT

DRI

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LEGAL NOTICE

NOTICE TO BIDDERS
OIL AND GAS LEASE SALE
MONDAY, AUGUST 18, 2008

The Commonwealth of Pennsylvania, Department of Conservation and Natural Resources, Harrisburg, Pennsylvania, will receive sealed bids for Oil and Gas Leases until **2 P.M.**, prevailing local time, **MONDAY, AUGUST 18, 2008**, at which time bids will be publicly opened and read for the leasing of State Forest lands in 18 tracts comprising a total of 74,023 acres in Tiadaghton, Loyalsock and Tioga State Forests located in Lycoming and Tioga Counties, Pennsylvania.

The Commonwealth of Pennsylvania is considered to be the owner of the oil and gas rights included in this lease sale offering but makes no warranty as to its ownership thereof. Bidders assume the risk of proving title.

Prospective corporate bidders must be registered to do business within Pennsylvania and be in good standing with the PA Department of State's Corporation Bureau to participate in the bid process.

Furthermore, all prospective bidders must be pre-qualified by the Department in order to participate in the lease sale. Prospective bidders must provide a bid guarantee security in the amount of Fifty-thousand dollars ($50,000.00) to the Department in one of the following forms: CERTIFIED CHECK, BANK CASHIER'S CHECK, A BID BOND ON A FORM PROVIDED BY THE DEPARTMENT OR A LETTER OF CREDIT ON A FORM PROVIDED BY THE DEPARTMENT, executed by both the prospective bidder and the surety company and made payable to the Commonwealth of Pennsylvania. The bid guarantee security is required from each prospective bidder and will cover all bids placed on one or more of the 18 tracts in this offering. A PERSONAL CHECK OR MONEY ORDER WILL NOT BE ACCEPTED. The bid guarantee security must be received by the Department no later than Monday, August 11, 2008. Bid guarantee securities will be returned to all bidders upon completion of the lease sale, unless any successful bidder fails to execute a lease tendered by the Commonwealth and to provide the required security within 30 days after the award and receipt of the contract, in which case the proceeds of the bid guarantee security will be retained by the Commonwealth and considered as liquidated damages.

All bids must be submitted on bid forms provided by the Department and must be submitted in a sealed envelope addressed to PA DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES, OFFICE OF CHIEF COUNSEL, 400 MARKET ST 7TH FLOOR, HARRISBURG PA 17101-2301. The bid envelope is to be marked Minerals – OIL & GAS TRACT _____. There shall be one bid per envelope.

Award decisions will be made public within 24 hours of the last lot closing at **www.dcnr.state.pa.us/forestry/oil_gas.aspx**.

The bid forms and other pertinent information regarding the lease sale including sample lease agreement, sample Lease Sale Bid Bond in a form acceptable to the Department, a detailed listing of the Lease Sale Tracts being offered, a complete set of tract maps in both .pdf and GIS shape file format, and the complete Environmental Review performed by the Department for the lease sale lands, can be found in digital form on-line at **www.dcnr.state.pa.us/forestry/oil_gas.aspx**. A hard-copy (printed to bond paper) document bid packet, described above, can be obtained only from the Department for a pre-paid cost of $100.00 per requested bid packet, or on CD ROM in digital form for $50.00 per bid packet, or in both paper and CD ROM combined for $150.00 per bid packet. Payment of bid packet fees should accompany a bid packet order request. Checks or money orders should be made out to "Commonwealth of Pennsylvania" and mailed to PA DCNR, Bureau of Forestry, Minerals Section, P.O. Box 8552, Harrisburg, PA 17105-8552. Only one request per company or individual for a hard copy of the pertinent bid documents will be filled by the Department.

Bids will be received and the lease awarded on the sum offered as a bonus for the first year's land rental. Lease will be awarded to the highest responsive bonus bidder. The total amount of the bid, along with the proper performance bond, must be submitted by the successful bidder when the lease is executed and returned to the Department of Conservation and Natural Resources. A bonus bid will not be acceptable if it is less than $1,000.00 dollars ($1,000.00) per acre.

Individual bidders must sign their bid; if a Corporation, the President or Vice-President must sign, attested to by Secretary or Assistant Secretary and the Corporate seal affixed. Any Corporate signer other than indicated will require a Power of Attorney or Letter of Authority to be attached to the bid. If Power of Attorney is used, an original copy must be provided for the lowest numbered tract being offered for lease and bid upon; on all subsequent tracts, a duplicate copy of the Power of Attorney may be used.

A bonus bid security of Ten Thousand Dollars ($10,000.00) will be required for each individual tract bid submission, and shall be provided in one of the following forms: a CERTIFIED CHECK, BANK CASHIER'S CHECK OR TRUST COMPANY TREASURER'S CHECK made payable to the Commonwealth of Pennsylvania. A PERSONAL CHECK OR MONEY ORDER WILL NOT BE ACCEPTED. For a successful bidder, the bonus bid security shall be applied to the bonus payment, which is the first year's rental. Bonus bid securities submitted by unsuccessful bidders will be returned at the end of the lease sale process.

The Department reserves the right to reject any and all bids, and waive any informalities, defects, or irregularities in the bids.

For details regarding the lease sale, or to order hard copy or CD ROM bid packets, write PA Department of Conservation and Natural Resources, Bureau of Forestry, Minerals Section, P.O. Box 8552, Harrisburg, PA 17105-8552. Or call Ted Borawski at 717-772-0269, Nathan Bennett 717-783-7940, or Amy Randolph at 717-783-7948; Fax: 717-783-7960; or visit the following website **http://www.dcnr.state.pa.us/forestry/**.

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McCain more like Democrats than Bush on energy

In another display of confusion about energy, Democratic leaders in Congress responded to oil-supply initiatives from the US president and the Republican who would succeed him as though they were identical.

They couldn't be more wrong. But give them time.

Sen. John McCain (R-Ariz.) gave a speech in Houston in which he switched

The Editor's Perspective

by Bob Tippee, Editor

position to call for exploration off the East and West Coasts.

McCain upholstered the appeal with harsh criticism of oil exporters and speculators, a restatement of opposition to limited leasing of the Arctic National Wildlife Refuge, and a pitch for his cap-and-trade plan for greenhouse-gas emissions.

The next day, President George W. Bush offered an energy package that differed importantly from McCain's in substance and tone.

Like McCain, Bush called for exploration of federal waters now inaccessible to producers. But he also advocated leasing of the ANWR Coastal Plain, restoration of an oil-shale leasing mechanism, and stimulation of refinery construction.

Bush mentioned the disadvantages of US reliance on foreign oil but did not, as McCain had done, harangue about exporters. Neither did he demonize speculators or veer off into global warming.

While the president did lapse into his vacuous rhetoric about "our addiction to oil," his message on oil supply was rounded and thoughtful. It made McCain's look half-baked and coarse. Obsessed as they are with "windfall profits" and "price gouging," Democrats saw no difference.

If Bush and McCain were serious about addressing gasoline prices, said Senate Majority Leader Harry M. Reid of Nevada in a typical Democratic response, "They would stop offering the same old ideas meant to pad the pockets of Big Oil and work with Democrats to reduce our dependence on oil, invest in renewable energy sources, crack down on excessive speculation, and stand up to countries colluding to shake down American consumers."

Someone who had heard McCain's speech logically might expect the Arizona senator to feel mostly the same way about Bush's plan.

He is not, of course, the first Republican to lean toward the other party on energy. This helps explain why so much promising federal land produces no oil or gas.

(Online June 20, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Markets ignore rumors of war

There was virtually no reaction in world oil markets when Iran denied the rumor that Israeli aircraft had attacked its nuclear facilities on June 23, saying such an act would be "impossible."

Normally tales of a possible war in the Middle East provoke a collective knee-jerk reaction from energy traders in fear of supply disruptions. When Israel's Transport Minister Shaul Mofaz earlier said Israel would mount such an attack if Iran continues its program for developing nuclear weapons, benchmark US light, sweet crudes shot to a then record intraday high of $139.12/bbl before closing at a record $134.54/bbl June 6 on the New York Mercantile Exchange, up a whopping $10.75 in the biggest 1-day gain ever at that point.

Oil price records were plentiful in June. As the US dollar fell, the August contract for benchmark US light, sweet crudes hit an intraday high of $140.39/bbl June 26 on the New York Mercantile Exchange, then closed at a record $139.64/bbl. Despite huge intraday swings, however, prices were held around $135/bbl for most of the month.

Crude prices climbed in early trading June 20 following reports that Israel's large military exercise in the eastern Mediterranean was really practice for a potential bombing attack on Iran's nuclear plants. Yet subsequent talk of an actual attack by bombers failed to generate any buzz at all.

"We had not heard the rumor before it was on the screen, and we still wonder if there was ever a rumor given the market's lack of price action," said Olivier Jakob at Petromatrix, Zug, Switzerland. "Israel has taken great care to publicize its 'Glorious Spartan' military exercise over the Mediterranean between May 28 and June 12, and we have to wonder where this rumor of an attack on Iran started from."

Israelis train

Under Glorious Spartan, more than 100 Israeli fighters together with bombers and rescue helicopters reportedly trained with the Greek air force over the Mediterranean, replicating the flying distance and mid-air refueling necessary for a flight from Israel to Iran. Maneuvers reportedly included low flying over mountainous terrain, a mock attack on a well-defended airbase in Greece, and practice with live ammunition at a nearby firing range for aircraft.

Jakob said, "There is definitely some psychological warfare going on, but turning to the operational realities we note that the Olympics run Aug. 8-24 and is followed by Ramadan Sept. 1-30." Ramadan is one of the most holy Muslim religious observances.

An Israeli air raid would need approval from the US military to penetrate Iraqi air space to reach Iran. "We would give little chance of a US nod for an attack during the Olympics; Israel might not care about striking during Ramadan," Jakob said. "Any attack during that timeframe would expose US troops in the [Persian] Gulf to greater grievance and risk."

Moreover, the US Navy had only one carrier, the USS Lincoln, in the gulf in late June. "Carrier deployment plans have been disturbed by a fire on the USS George Washington on its voyage from Norfolk, [Va.,] to the East Pacific, forcing it to stop in San Diego for repairs until August. The USS Reagan is stationed near Hong Kong and unless it was to sail to the gulf we will view the possibility of air bombardment on Iran not an immediate reality," Jakob said at that time.

However, John Bolton, former US ambassador to the United Nations and an advocate of hard line foreign and defense policies who is influential among conservative Republicans, said he expects Israel will likely to attack Iran sometime "between the November presidential election in the US and the inauguration of the new president." Bolton was US representative to the UN August 2005-December 2006 on a recess appointment. He is now counsel to the law firm Kirkland & Ellis in Washington, DC.

Mohamed ElBaradei, director general of the International Atomic Energy Agency under the UN, claims an attack on Iran would turn the Middle East into "a fireball." He threatened to resign his office if there is an attack.

Meanwhile, the European Union imposed new sanctions on Iran, curbing travel for certain Iranians and freezing some banking assets. "The carrot and the stick approach continues as on the same day the US administration leaked to the press that it was debating opening a US diplomatic interest section in Teheran. In order to do this without the administration appearing to the public as capitulating would probably need to be accompanied by another toughening of sanctions," Jakob said.

(Online June 30, 2008; author's e-mail: samf@ogjonline.com)

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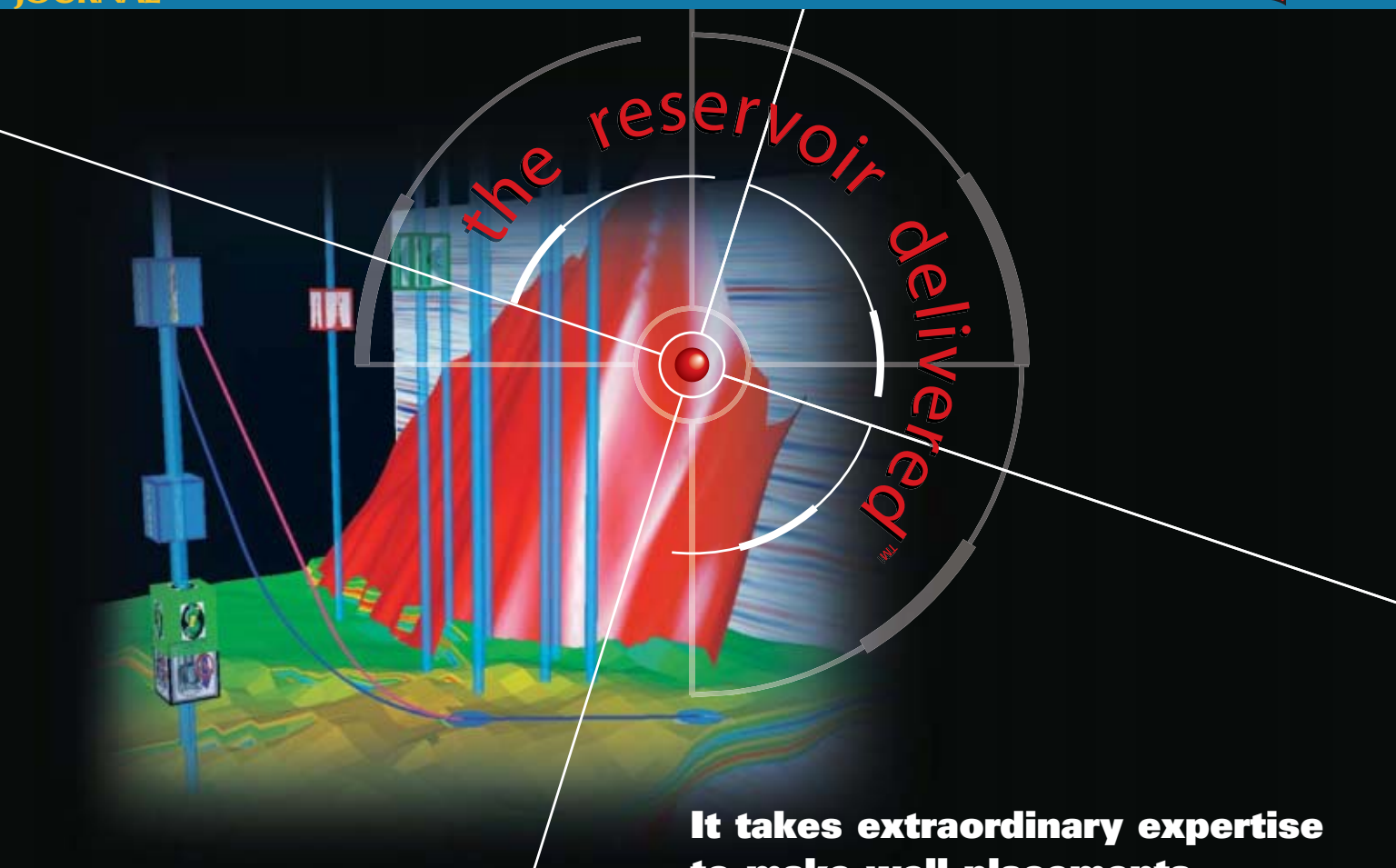

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Technology Forum

Downhole Tools

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BJ Services' ComPlete ™ MST (multizone, single-trip) system is shown being deployed in a well in Indonesia. The downhole tool system facilitates single-trip gravel- or frac-packed completions across multiple production intervals. Photo courtesy of BJ Services.

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Downhole tools basket evolving toward all-digital oil field

As oil and natural gas drilling and production activity fans out into ever more hostile environments and increasingly complex geology, the basket of downhole tools available to the operator is growing more sophisticated.

Much of the emphasis is on taking the guesswork out of what is happening downhole, as industry continues to take steps toward the "Holy Grail" of the all-digital oil field.

That's critical for companies coping with the high temperatures and pressures of deep gas plays, the complex well geometries of multilateral and other extended-reach wells, and complicated logistics of deepwater subsea completions.

"New devices that are under development can economically provide real measurements of downhole conditions, thereby providing valuable information that can be used to either confirm or contradict our estimates or highlight areas where we can improve."

— Blake Hammond, Weatherford

"We see a need for step-change technology required to recover unconventional resources. Where the western E&P companies have increasing difficulty to get access to conventional reserves—as they are produced by the NOCs [national oil companies]—exploring and producing unconventional reserves is their new focus. In order to make this happen, complete new technologies are required..."

— Martin van Onna, Airborne Composite Tubulars

Blake Hammond, global product line manager for through-tubing, Weatherford International Ltd., notes that the industry is working on "more effectively collecting job-related data, but that is primarily the data a field engineer is able to collect based solely upon the signals he receives on the surface: what was his pump pressure, what BHA did he run, what was the fluid he pumped, etc.

"New devices that are under development can economically provide real measurements of downhole conditions, thereby providing valuable information that can be used to either confirm or contradict our estimates or highlight areas where we can improve."

New tools for unconventional resources

Challenges abound for service and supply companies developing new downhole tools, notably in the area of unconventional resources, according to Martin van Onna, general manager, Airborne Composite Tubulars BV, The Hague.

"We see a need for step-change technology required to recover unconventional resources," he says. "Where the western E&P companies have increasing difficulty to get access to conventional reserves—as they are produced by the NOCs [national oil companies]—exploring and producing unconventional reserves is their new focus.

"In order to make this happen, complete new technologies are required, ranging from completely automated drilling equipment, capable of drilling wells faster and in large quantities, to nonconductive tubulars, with integrated electrical conductors and optical fibers."

HT/HP wells

Even some conventional oil and gas resources offer extreme challenges for downhole tools. A case in point is the high-temperature/high pressure (HT/HP) well, according to David Walker, BJ Services director of completion technology.

"Individually, high pressure and temperature are minor concerns for oil field equipment, and specialized tools are available for one condition or the other," notes Walker. "But combining both creates a design nightmare."

In addition to affecting material strength—which affects pressure rating—high temperatures increase corrosion effects and increase the chance for stress cracking. Even with high-strength metals and elastomers, oil field equipment designed for use in lower pressure and temperature conditions needs redesign, Walker adds.

"Individually, high pressure and temperature are minor concerns for oil field equipment, and specialized tools are available for one condition or the other. But combining both creates a design nightmare."

— *David Walker, BJ Services*

"For example, BJ Services' new CompSet™ Extreme packer is functionally the same as prior CompSet packer technologies, but it was redesigned to enable high-pressure cycling to 12,500 psi working pressure at 350 °F, and a 15,000-psi version is in the testing phase," he says. "Packers and completion systems for even more extreme conditions are in the research phase, with operators looking ahead to developments that may see pressures up to 30,000 psi and temperatures above 400 °F."

The next game-changing tools in the area of HT/HP wells will include advanced high-temperature motor systems, sealing element systems, metal-to-metal sealing technologies, setting tools, and isolation tools, says Mark McGurk, product line director, Baker Oil Tools division of Baker Hughes.

Smart wells and safety

At the same time, the sheer increasing complexity of downhole tools—especially the proliferation of safety-related sensors and monitoring equipment—has raised some safety concerns of its own, van Onna adds.

"In the drilling industry, safety has been improved over the years by adding safety-related equipment, procedures, and working methods," he says. "This has made much equipment and working procedures more complex and hence limits further safety improvements. Take for instance the ATEX requirements for the North Sea, where, combined with a tendency to move from Zone 2 to Zone 1, the equipment being deployed is filled with pressure, temperature, gas sensors, etc., making the equipment prone to failure—which in itself increases risks on safety. For instance, with current gas sensor alarm levels, often units shut down only because someone has a stain on his coveralls. This in itself reduces safety rather than improving it."

The only way to break through this safety ceiling is to use "smart well" technology to make operations more simple rather than more complex, van Onna contends.

"This can be achieved by implementing technologies that allow processes to be automated. In wireline operations, for instance, the grease injection system and the BOP control can be linked to the wireline unit control, such that, in an emergency, automatically the wireline unit shuts down, the grease injection pressure is increased, and the grease return line is closed."

Other technologies available to simplify operations through downhole automation and thereby increase safety are aimed at increasing the amount of available data in order to take measures up front and avoid hazardous situations from occurring, according to van Onna.

"For instance, by integrating power conductors and optical fibers into composite coiled tubing, unprecedented data communication capability is achieved, allowing for the operators to know more about the downhole situation. Data on items such as pressure and temperatures, borehole stability, vibrations, tool-face positioning, etc., allow for automation of the drilling process, improving safety."

BJ Services' Walker contends that the most important innovation in downhole tools has been the development of downhole flow control valves.

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"These valves are utilized in well completions to allow selective production of multiple reservoirs without the need for mechanical intervention," he says. "This is extremely important in optimizing completions in subsea wells."

The utilization of remotely operated valves in sand control environments has been primarily limited to two zones per well, according to Walker: "An area of growth for intelligent wells in sand control environments will be the integration of downhole flow control equipment with the new single-trip multizone completions.

"Development of these systems will allow access and control of multiple reservoirs (five or more), giving the operator the ability to optimize flow rates and maximize recovery from a given wellbore or field. This is will be extremely important in the deepwater and ultradeepwater subsea environments."

The most important innovation in downhole tools has been the development of downhole flow control valves: "These valves are utilized in well completions to allow selective production of multiple reservoirs without the need for mechanical intervention. This is extremely important in optimizing completions in subsea wells."

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New downhole tools are also essential for the industry coping with stringent environmental regulations: "A number of operations, such as stimulation, require the construction of a full rig site, leaving a considerable footprint on the environment. Rigless intervention tools can lessen that footprint."

— *Mark McGurk, Baker Oil Tools*

New downhole tools are also essential for the industry coping with stringent environmental regulations, according to McGurk.

"At Baker Oil Tools, our R&D philosophy incorporates solutions to environmental issues from the outset of any R&D project," he says. "A number of operations, such as stimulation, require the construction of a full rig site, leaving a considerable footprint on the environment. Rigless intervention tools can lessen that footprint."

Completions

One of the biggest costs associated with completing offshore and complex onshore oil or gas wells is the nonproductive time (NPT) it takes to run or remove tools from the wellbore, notes Walker.

"To minimize that NPT, the ComPlete™ MST (multizone, single-trip) tool system facilitates single-trip gravel- or frac-packed completions across multiple production intervals," he explains. "Its design allows complete flexibility in sand placement techniques, including positive, selective isolation of all zones during completion, stimulation, and production operations.

According to Walker, as many as six zones have been isolated in one trip to date in operations from Indonesia to the Gulf of Mexico.

"The result is an effective reduction in completion cycle time—and cost—by 20 to 50 percent compared with standard multizone completion technologies that require multiple trips."

Similarly, the new DirectStim™ multizone stimulation tool developed by BJ Services cuts completion and stimulation time on multizone vertical or horizontal wells by eliminating the need for wireline gun perforating runs, individual zonal isolation devices, (such as bridge plugs), and post-stimulation milling runs, Walker claims.

The tool is run into a well and either cemented in place using acid-soluble cement or isolated using inflatable or swellable packers.

"This flexibility allows the technology to work in a variety of formations and wellbore conditions, says Walker. "Reliable hydraulic and ball-actuated sliding sleeves and baffles sequentially expose the wellbore to the formation pay zones (and isolate prior zones) for fracture stimulation. When all the zones are complete, the well can flow without additional intervention."

Well interventions

A host of new downhole tools is creating new efficiencies for the operator in a number of areas, Baker Oil Tools' McGurk points out. New composite tools add value to operating companies' operations by significantly reducing the time required to complete and stimulate wells and bring them back on production, he adds.

For overbalanced and underbalanced wells, "enabling technologies such as downhole lubrication valves allow placement of complete intervention strings rather than surface lubrication of short sections as at present," he says.

McGurk also cites the value for well testing of improved isolation and sealing technologies, including metal-to-metal sealing, all with V0 gas-tight classification.

As for sand control, he contends that "the future lies in

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behind-pipe isolation technologies and techniques, such as swellable packers and noncemented mechanical isolation packers such as the Baker MPas."

For plugging and abandonment (P&A) operations, McGurk notes the following downhole tool technology areas ripe for "changing the game":

- Isolation tools that have been developed for the P&A market that meet the stringent design verification criteria and sealing performance of the V0 classification.
- High-performance cutting technologies for exotic alloys.
- Methods of working with light intervention vessels and their subsequent move to deep water.
- Enabling technologies such as downhole lubrication valves that allow live-well placement of complete intervention strings.

Greater specialization

Weatherford's Hammond notes that as the well intervention business has evolved, he has recently seen a positive move with respect to distilling the service side of the intervention market into various distinct disciplines.

"Initially, as the intervention industry developed, it did so primarily on the backs of the deployment companies," Hammond says. "Those with the work strings that deployed the downhole systems were primarily expected to provide the expertise on all aspects of the operation.

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New downhole tools bolstering CT drilling, service applications

Coiled tubing (CT) drilling and well service applications are being improved by a host of new downhole tools to serve this fast-growing area of drilling and production.

As demand for CT drilling and well services grows, service and supply companies are responding with new downhole tools for horizontal and extended-reach/multilateral drilling, underbalanced and overbalanced drilling, well stimulation, cleanouts/solids removal, frac jobs, perforations, cutting and milling, and plug removal.

Among the leaders in this field are BJ Services and the Baker Oil Tools division of Baker Hughes.

Extended-reach/multilateral wells

Operators are increasingly developing new fields and redeveloping mature fields by drilling multilateral wells to extend reservoir access and enhance the effective drainage from minimal surface facilities, notes John Misselbrook, BJ Services senior advisor for coiled tubing technology.

"Stimulating or cleaning out these multilateral wells can be challenging without technology designed to navigate and properly enter the various branches," he says. "BJ Services accomplishes these operations using the coiled tubing-conveyed Lateral Entry Guidance System (LEGS™) tool, an intelligent sys-

tem for navigating the junctions of a multilateral well. Advances to the tool in the last year have increased its effectiveness in underbalanced or subhydrostatic wells."

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"I believe we will continue to see significant technology strides in the development of 'tractoring' systems and other such methodologies, such as vibration-inducing tools to break friction lockup" in CT applications.

— *Gordon Mackenzie, Baker Oil Tools*

The main issue relating to CT in extended-reach applications is in the ability "to actually get the coil and relevant bottom hole assembly (BHA) to the required intervention depth due to the effects of helical buckling and 'lockup' and still be able to have any available setdown weight when there (if required) to perform the planned operation," says Gordon Mackenzie, Baker Oil Tools product line manager, Thru-Tubing Intervention. "I believe we will continue to see significant technology strides in the development of 'tractoring' systems and other such methodologies, such as vibration-inducing tools to break friction lockup."

Over/underbalanced wells

One of the main advantages to the use of CT is its ability to work in a "live" well environment or effectively in an underbalanced condition, according to Mackenzie. "Theses conditions currently exist in most of the 'brownfield' areas and are suited for CT intervention, leading to the requirement—for many reasons—to work with a nitrified system, which most notably would be in the ability to circulate cuttings/debris back to surface in an underbalanced/depleted well.

"The continued development of downhole tool systems to function with straight nitrogen or two-phase flow will be required to enhance such operations. Developments such as workover motors for straight gas operation with operational output parameters at least equal to today's equidistant stator X-treme™ motors will be required.

"Today we have and continue to see the development and utilization of some downhole systems that allow for the separation of fluid and gas above the motor to allow the best of both worlds, namely the fluid drive properties for optimum motor performance and effective circulation of the solids/cuttings to surface using gas."

Frac jobs/perforations

Significant investments and strides are being made, predominantly in the North American markets, in the development of solutions aimed at the CT frac market, notes Mackenzie.

"I believe that we will see many more solutions being delivered as we go forward," he says. "We are currently prototype-testing a CT-deployed, fixed straddle system to provide reliable and repeatable downhole isolation of selected zones for both hydraulic and proppant fracturing operations.

"One of the main technical advantages offered by this system will be in its unique valve arrangement that has been designed to support large volumes of coarse frac slurries pumped down through the CT rather than the annulus.

"The straddle system makes the most use of the inherent advantages of CT operations, such as improved HS&E, reduced personnel requirements, faster trip times, and smaller operational footprint."

For CT-assisted fracture stimulation, Misselbrook notes, "the OptiFrac™ SJ downhole tool combines a casing-collar locator for extremely accurate depth determination with a sand jetting tool that cuts clean, large holes in the casing.

"Jetting leaves no debris in the perforation tunnel and creates less damage than conventional shape-charge perforations.

"The resulting perforations have low near-wellbore pressure loss and tend to initiate simple hydraulic fractures—which minimize tortuosity, a key factor both in ensuring proppant transport into the fracture and in producing gas through the newly created channel."

BJ Services recently ran a record-length (926 m) BHA on CT off New Zealand, notes Misselbrook: "The BHA comprised 900 m of perforating guns along with spacers, connectors and other tools and ran successfully on 1¾-in. coiled tubing.

"The use of proprietary flow analysis and tubing force simu-

lation software was critical to ensure safe, reliable running of this tool in and out of the well."

Cleanouts

One trend in well construction is the increasing use of large-diameter, deviated, and horizontal wellbores, Misselbrook points out.

"Cleaning solids from these wells can be extremely challenging because of the equilibrium solids beds that form behind the BHA while tripping in with conventional CT cleanout tools," he says.

One trend in well construction is the increasing use of large-diameter, deviated, and horizontal wellbores: "Cleaning solids from these wells can be extremely challenging because of the equilibrium solids beds that form behind the BHA while tripping in with conventional CT cleanout tools."

— John Misselbrook, BJ Services

The patented Tornado® cleanout process from BJ Services uses a novel tool, according to Misselbrook: "When running in the hole, high-energy, forward-facing jets break up and fluidize any compacted fill; when pulling out of the hole, low-energy, backward-facing jets re-entrain solids from the equilibrium beds, resulting in a much more efficient and complete cleanout than was possible using older technologies."

For solids removal from wells with very low bottomhole pressure, the BJ Services Sand-Vac® tool is a key technology, contends Misselbrook.

"Based on jet pump technology, the tool has been used in low-pressure wells from Oman to Alaska for 15 years, but recent design upgrades have enabled removal of larger proppant sizes, improved jetting rates, and added a switchable ability to remove jetted fluids from the well.

"The modified tool is at work on the North Slope of Alaska this summer with a record-length (19,100 ft) reel of 2⅜ by 1π-in. concentric coiled tubing."

Acidizing/wellbore cleanout

Using a proprietary coiled tubing-conveyed tool and a patented technique, StimTunnel™ technology from BJ Services creates "tunnels" in carbonate rock to economically increase wellbore contact with the reservoir, says Misselbrook.

Acid pumped through the tool creates stable holes, without utilizing a drill bit, by dissolving the formation. Any acid not consumed in hole construction leaks off into the rock, creating "wormholes" that enhance the flow capacity while extending contact with the reservoir or the existing natural fractures.

For removing deposits of hard scale and solids—including silicates and barium sulfate composites—BJ Services uses the Roto-Jet® tool to introduce stress cycling to the deposit by accurately controlling the jetting nozzle's rotational speed.

"Each pass of the jetstream induces local tensile stress in the scale, causing the brittle scale to shatter into small particles for easy transport to surface," Misselbrook says. "The Roto-Jet nozzle can uniformly place fluid behind a screen across an entire interval to fully remove precipitates without damaging the screen or sand.

"To further improve cleanout efficiency in gravel packs, the Roto-Pulse™ technique and jetting head create vibration from the jets to mobilize insoluble plugging fines without damaging the gravel pack."

Cutting and milling

CT cutting and milling operations is another area where Mackenzie believes technology development is adding significant operator value.

"On the CT tubing front, there will be substantial impact gained with the further introduction of insert-type mills that can create a casing exit before continuing on into the formation," he says. "These hybrid 'mill and drill' systems are already proving themselves effective in underbalanced window cutting and exit operations. "The ability to couple a mill/drill bit onto the directional BHA reduces the amount of coiled tubing trips by allowing the window to be cut and the curve to be drilled in a single run. As technology advances, one mill/bit may be run to complete the entire operation."

The increased use of exotic materials being used in wellbores for completion equipment, such as tubing, cut-to-release production packers, seating nipples, formation isolation-type ball and flapper valves, and the like, is necessitating increased R&D in order to supply "fit-for-purpose" cutting and milling systems to answer the tough demands set by the use of such materials, according to Mackenzie.

"At Baker Oil Tools, we are proud of our reputation as being the pre-eminent supplier of solutions and 'industry firsts' in this arena," he claims. "As a company, we revolutionized the downhole cutting industry with the introduction of METAL MUNCHER™ carbide inserts, and the continued evolution thereof, increasing previous milling penetration rates by as much as 1,000%.

"The introduction of our proprietary equidistant stator X-treme™ workover motor technology allowed us to make use of coiled tubing to provide rotational services that had the ability to be run in higher temperature and hostile environments with the greatly increased torque and optimized RPMs at lower operating pressures, as required for efficient milling operations utilizing CT.

"We are aggressively pursuing our technology drive with

continued workover motor R&D work and a specific, highly experienced, engineering cutting-and-milling single-focused team. As our insert technology has advanced, our successes have been passed on to our customers, with the development of systems to provide fit-for-purpose solutions for the cutting or milling of material as diverse as 13% chrome, 25% Super Duplex chrome, SM2535, Inconel™ 718, and 925 Incoloy™.

Baker Oil Tools' provision of engineering, tools, and application services to a North Sea customer allowed for the successful completion of the world's first casing exit window to be created out of duplex 25% chrome casing, Mackenzie cites.

"This successful campaign of exits, where actual wellbore operations saw a 60% milling time improvement over onshore field trials, prompted the client drilling superintendent to say, 'The windows were critical to the viability of the Scott TTRD project. This new milling technology was developed by an excellent approach to testing and engineering" and the director of global drilling to comment, 'The driver for us was obvious; by overcoming a technical barrier, we opened up the possibility of achieving improved returns from a maturing asset.'"

The Baker Oil Tools DELTA Exit System™ was developed from experience garnered from creating a casing exit on a well-publicized underbalanced CT drilling campaign in the Middle East.

"These particular wells required the casing exit to be milled while still maintaining gas production, which necessitated the use of a predominantly gas driven power medium," Mackenzie notes. "However, milling a casing exit in such an environment created significant vibration issues that ultimately led to the development of the single-trip DELTA Exit System to mitigate such problems.

"One of the initial runs of the DELTA Exit System allowed for a window to be milled with coiled tubing prior to the open-hole section being drilled utilizing the Baker Hughes Inteq CoilTrak system. Two laterals, with a combined total footage of 3,593 ft, were created out of the 7-in. liner prior to the retrieval of the DELTA whipstock back through the 5.625-in. restriction."

Plug removal

The largest market for plug removal operations presently is in North America in the removal of composite bridge and frac plugs, according to Mackenzie.

"Composite plugging devices are required to be removed quickly and reliably—and in many cases in multiples—from the wellbore in a single trip in order to achieve client returns," he says. "The average CT drill-out time for a cast iron bridge plug is approximately 1 hr, as compared with less than 20 min. for a comparable composite plug. When multiple cast iron plugs are used in a wellbore, the drill-out time begins to grow exponentially, a factor that is not evidenced in composite technology operations.

"At Baker Oil Tools, we have and continue to invest significant R&D into the operations of design, manufacture, supply, and installation of the composite plugging devices and associated setting equipment, as well as the investment in technology for the coiled tubing removal of these same plugs.

"We have multiple examples of operations where we have set and removed significant quantities of composite plugs for frac operations. In one such instance, the operator required the setting and subsequent removal of 18 composite bridge plugs within its 4.5-in., 13.50#/ft tubing string.

"After performing successful frac operations, a 3.7-in. OD Opti-Cut™ dressed mill was run in conjunction with a Baker Hughes Inteq 2.875-in. Navi-Drill™ VIP™ workover motor and applicable CT BHA, on 1.75-in. CT. At a flow rate of 84 gpm and a maximum weight on bit of 3,000 lb, all 18 bridge plugs and an additional 120 ft of wellbore fill were removed in a single coiled tubing trip.

"Looking forward, we are starting to see increased areas of opportunity with very large growth potential for coiled tubing frac plug operations and subsequent removal operations outside the North American markets."

Technology gaps

Determining well depth is a still a challenge for CT applications, according to Mackenzie.

"It is well known that accurately determining depth in a well with coiled tubing is problematic, and the question of accurate, real-time depth correlation when intervening on coiled tubing is one that still needs to be addressed.

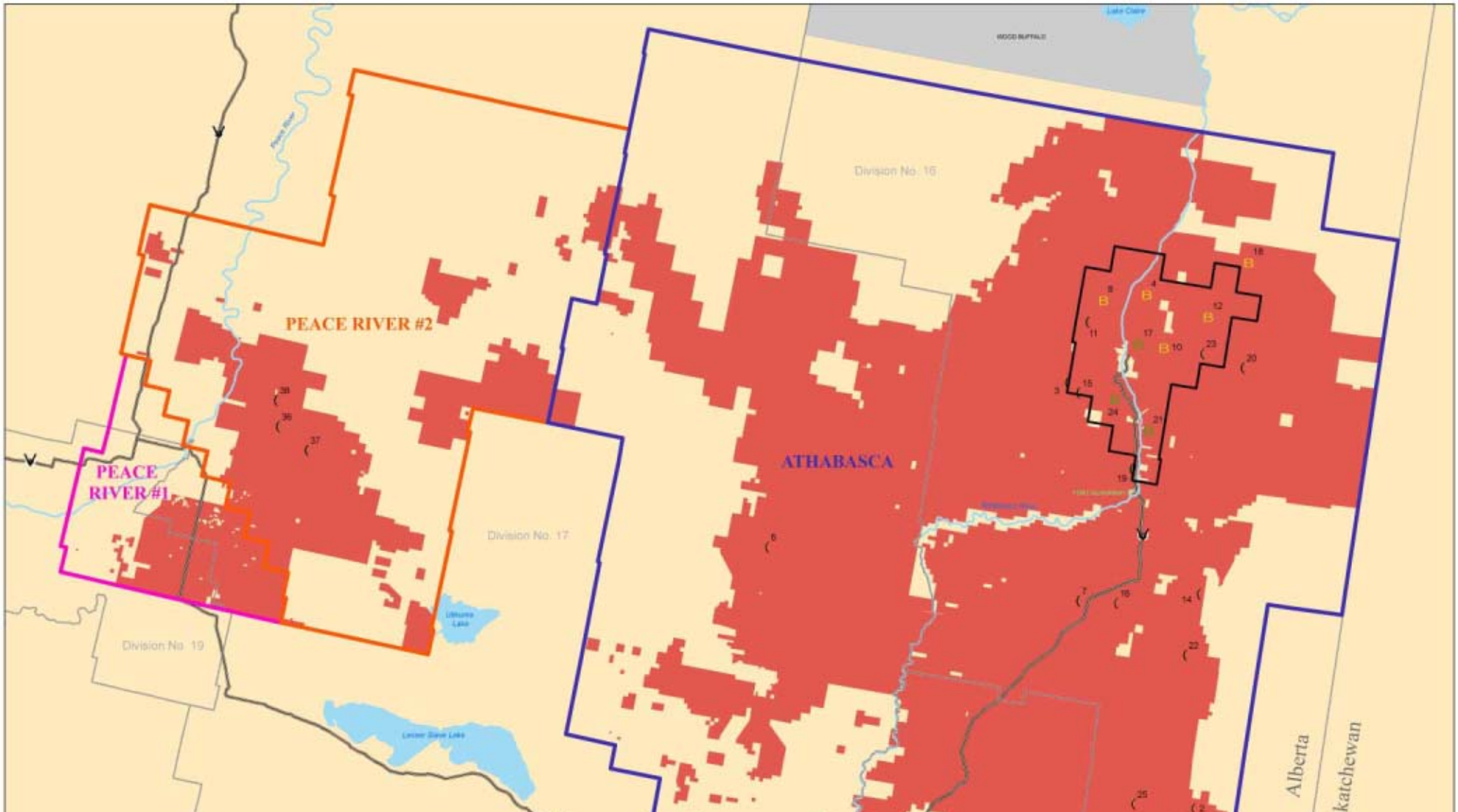
— *Gordon Mackenzie, Baker Oil Tools*

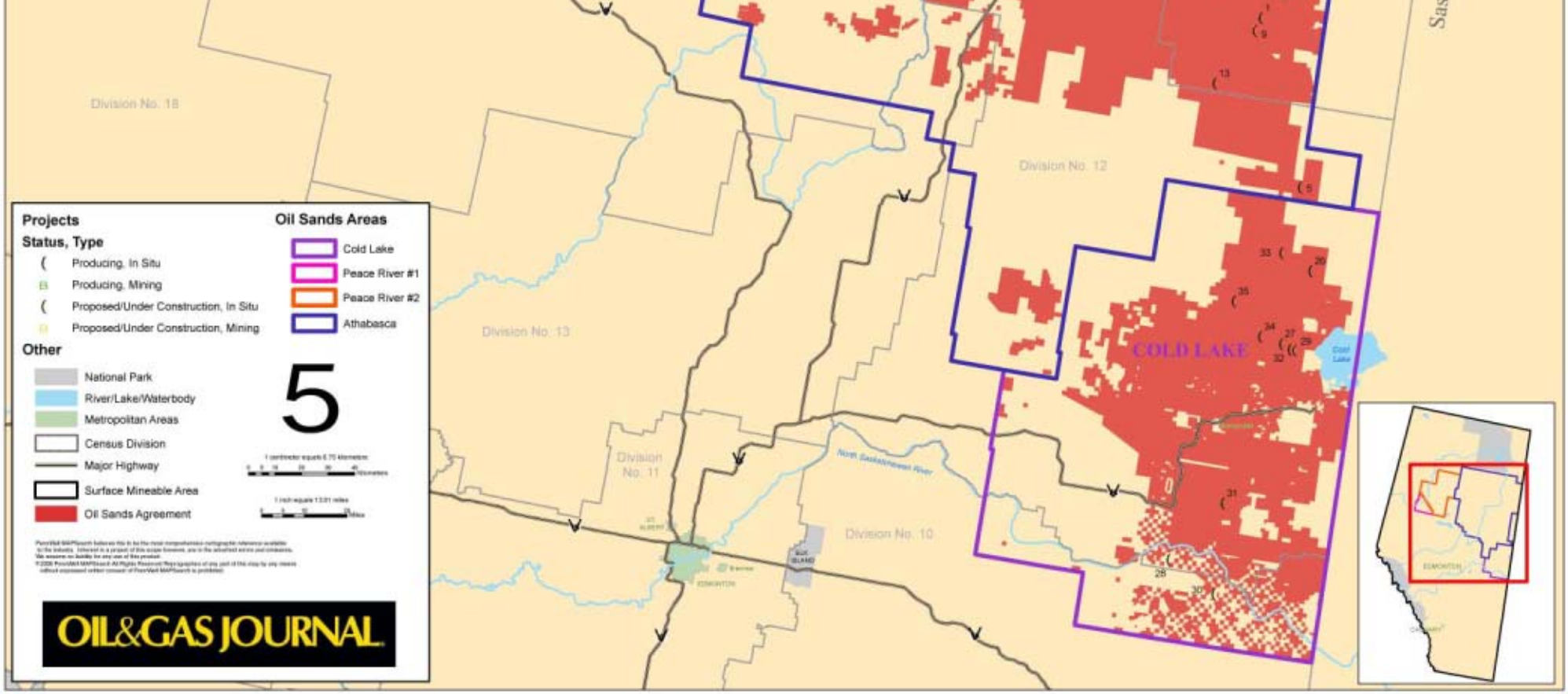
"It is well known that accurately determining depth in a well with coiled tubing is problematic, and the question of accurate, real-time depth correlation when intervening on coiled tubing is one that still needs to be addressed.

"Although there are any number of devices and methodologies that can be employed to help determine depth, I believe there still to be a technology gap to be answered here."

On the lateral well front, one of the main issues prevalent today is in the identification of where the required lateral to enter is and how to reliably and consistently get the CT and related BHA to enter it, Mackenzie adds: "Some systems do exist today to help in this, but I would suggest there is still a technology gap to be filled here."]

ALBERTA OIL SANDS - EXISTING AND PROPOSED PROJECTS





Athabasca Oil Sands Area

ID	Project Name	Status
1	Christina Lake (EnCana)	Producing
2	Christina Lake (MEG Energy)	Proposed/Under Construction
3	Dover SAGD	Producing
4	Fort Hills	Proposed/Under Construction
5	Foster Creek	Producing
6	Germain	Proposed/Under Construction
7	Hangingstone	Pilot Plant
8	Horizon	Proposed/Under Construction
9	Jackfish	Proposed/Under Construction
10	Jackpine Mines Phase I & II	Proposed/Under Construction
11	Joslyn	Producing
12	Kearl	Proposed/Under Construction
13	Kirby	Not Producing
14	Long Lake	Proposed/Under Construction
15	MacKay River	Producing
16	Meadow Creek	Proposed/Under Construction
17	Muskeg River	Producing
18	Northern Lights	Proposed/Under Construction
19	Poplar Creek (Electrothermal)	Not Producing
20	Suncor Firebag	Producing
21	Suncor Steepbank/Millenium	Producing
22	Surmont	Producing
23	Sunrise	Proposed/Under Construction
24	Syncrude 21	Producing
25	White Sands (THAI Recovery)	Proposed/Under Construction

Cold Lake Oil Sands Area

ID	Project Name	Status
26	Burnt Lake	Producing
27	Cold Lake	Producing
28	Elk Point	Producing
29	Hilda Lake	Proposed/Under Construction
30	Lindbergh	Producing
31	Murphy Lindbergh	Producing
32	Orion	Experimental
33	Primrose	Producing
34	Tucker	Producing
35	Wolf Lake	Producing

Peace River #2 Oil Sands Area

ID	Project Name	Status
36	Peace River	Producing
37	Shell Peace River (Pads 42 & 43)	Producing
38	SR 2000	Producing

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www.oilandgasmaintenance.com

PIPELINE REHABILITATION & MAINTENANCE ™
www.pipeline-rehab.com

Call for Papers

The Gulf International Convention & Exhibition Centre, Manama, Kingdom of Bahrain, **19 - 21 January 2009**

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Connecting with IDEAS

Oil & Gas Maintenance Technology and Pipeline Rehabilitation and Maintenance conference and exhibition is the Gulf's premiere forum for oil & gas maintenance and reliability technologies and the latest developments in pipeline rehabilitation and maintenance issues.

This event will attract the oil & gas industry's leading professionals from across the region and the globe to discuss the latest industry hot topics including predictive and preventive maintenance, reliability and asset management, and maintenance management as well as examine issues centered on the fitness-for-purpose question of oil and natural gas transmission lines. From vibration analysis to corrosion control to contracting practices, the program will address maintenance and inspection issues affecting tanks, compressors, rotating equipment, pipelines, gas plants, refineries, instrumentation, and more. Held simultaneously, the exhibition will showcase technologies and products displayed by dozens of exhibiting companies. The three-day event will draw hundreds of visitors to the show floor to network with leading suppliers, consultants and service providers on Middle Eastern maintenance and reliability solutions.

The event once again will be co-hosted by **Saudi Aramco and BAPCO**

FOR DETAILS ON HOW TO SUBMIT, SEE BACK PAGE.

DEADLINE FOR SUBMISSION: 21ST JULY 2008

Oil & Gas Maintenance Technology Track

The second annual Oil & Gas Maintenance Technology Conference, like the successful inaugural event in 2007, will highlight practical solutions to real problems across a range of maintenance topics.

The Conference will bring together professionals from the Middle East and around the world. Its focus is on a region where maintenance problems are big – and where solutions have global importance.

Scope of Sessions

Predictive and Preventative Maintenance
Fundamentals of Best-in-Class Maintenance
Roadmap to Best-in-Class in Maintenance
Maintenance Knowledge Management
Aligning Knowledge/Training Towards Performance Excellence
Maintenance Best Practices
Maintenance Risk Management
Maintenance Change Management
Maintenance Benchmarking
Contracting practices - outsourcing
Effective Maintenance KPI's (Key Performance Indicators)
State of the Art Maintenance Tools & Equipment
Industrial Maintenance Solutions
The Need and the Gain on Asset Management
Profit Opportunities and Asset Utilization
Effective Utilization of CMMS (Computerized Maintenance Management System)

Technical Overview

UPSTREAM

DOWNHOLE DRILLING AND RESERVOIR MAINTENANCE TECHNOLOGY

- Advances in reservoir maintenance technology
- Preventing loss of reservoir porosity, EOR, sand control
- Advances in downhole / drill string inspection & monitoring
- Maintenance of equipment, such as:
- Artificial lift systems
- Electronic, pneumatic, and hydraulic control systems
- Flow meters
- Transfer pumps
- Downhole tubing and casting
- Production separators, tanks, flowlines, filters and other processing vessels
- Scada systems

Midstream

PRODUCTION AND PIPELINE SYSTEMS

- Corrosion control and monitoring
- Advances in monitoring / inspection technologies for long-distance transmission oil and gas pipelines
- Top-of-line corrosion challenges mainly in sour gas, sour crude and condensate lines
- Sour gas corrosion challenges – removal of H2S, preventing piting corrosion

Downstream

REFINERIES AND PROCESS INDUSTRIES

- Advances in monitoring technologies for refinery equipment
- Advances in predicting equipment reliability
- Repair, rehabilitation and cleaning of fouled or damaged equipment
- Prevention of stress corrosion cracking
- New processes, material and maintenance strategies to minimise fouling from off gases

Pipeline Rehabilitation and Maintenance Track

Oil and gas prices continue to rise. Material costs have risen with them. The combination has placed a greater premium than ever on effective management of pipeline assets, raising the importance of state-of-the-art maintenance and rehabilitation. The difficulties associated with efficiently transporting produced hydrocarbons from increasingly remote or hostile locations will maintain this premium into the future.

These converging factors are important to all who operate pipelines, deliver material through them, or service them. The role of Middle East producers in this equation has expanded, placing the pipelines in the center of this equation.

The Pipeline Rehabilitation and Maintenance conference returns to Bahrain as a forum through which experiences gained in rehabilitation and maintenance and new possibilities are discussed. The previous nine conferences have established the value of this event and the current edition will present new opportunities for advancing safe, efficient, and reliable methods of protecting pipeline transportation into the future.

Scope of Sessions

Pipeline construction in challenging soil environment
Pipeline manufacturing and metallurgy
Rehabilitation methods and materials technology
Risk assessment and area classification
HAZOP (Hazard and Operability) studies, security and integrity
Leak detection and cathodic protection systems
Inspection of CP systems
Inline inspection and development of repair plans
Risk Assessment and preventative measures
Offshore pipeline inspection, repair and rehabilitation
Selection of valves
Project Management

Technical Overview

PIPELINE INSPECTION & MAINTENANCE

- Pipeline damage, measurement and assessment
- Epoxy shells
- Clock Spring and composite repairs
- PLIDCO clamps
- Online inspection work
- Inline scraper tracking by using latest techniques
- Scraper trap maintenance
- Sewage and replacement of PRS installation
- Hydrostatic
- Advanced Pressure Testing (APT)
- De-watering and drying of sales gas pipelines
- Caustic dosing
- Valve maintenance
- CO2 and Biofuels – Conversion hazards, maintenance worries.
- New leak detection technologies.
- Third-party damage – Accidental
- Security (re: deliberate damage)
- Greenhouse gas moderation (R&M implications)
- Direct Assessment methodologies.
- Coating technology
- Polymer and epoxy degradation
- Effect of cathodic protection
- Environmentally assisted cracking.
- SCC
- Metallurgy
- Microbiological corrosion
- Cathodic protection

PLANT INSPECTION & MAINTENANCE

- Safety management
- Quality control
- Plant reliability
- Energy conservation
- Planning / scheduling of equipment testing
- General shutdown guidelines
- Tower and vessel inspection & repair
- Furnace and boiler inspection & repair
- Heat exchangers
- Tanks

SUBSEA INSPECTION & INTERVENTION

- Magnetic particle inspection
- Ultra sonic thickness gauging
- Eddy current flaw detection
- Cathodic potential surveys
- Impressed current inspection
- C.V.I. and G.V.I. weld inspection
- Digital stills photography
- Video surveys
- Subsea control modules
- Multiphase flowmeters
- Inspection tools
- ROVs & AUVs
- Dredging
- Subsea Inspection
- Drilling support operations
- Pipeline burial/de-burial

HOW TO SUBMIT YOUR ABSTRACT

Abstract Submittal

Presentations must be of interest and of practical value to executives, managers, engineers engaged in the petroleum industry. Papers will be selected based on a review of abstracts by the Advisory Board. Papers must not be commercial in nature.

Your abstract should address one or more of the topics pertaining to one of the technical areas outlines in this document.

Please submit your abstract **online** by **July 21st, 2008**

Online: www.oilandgasmaintenance.com
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