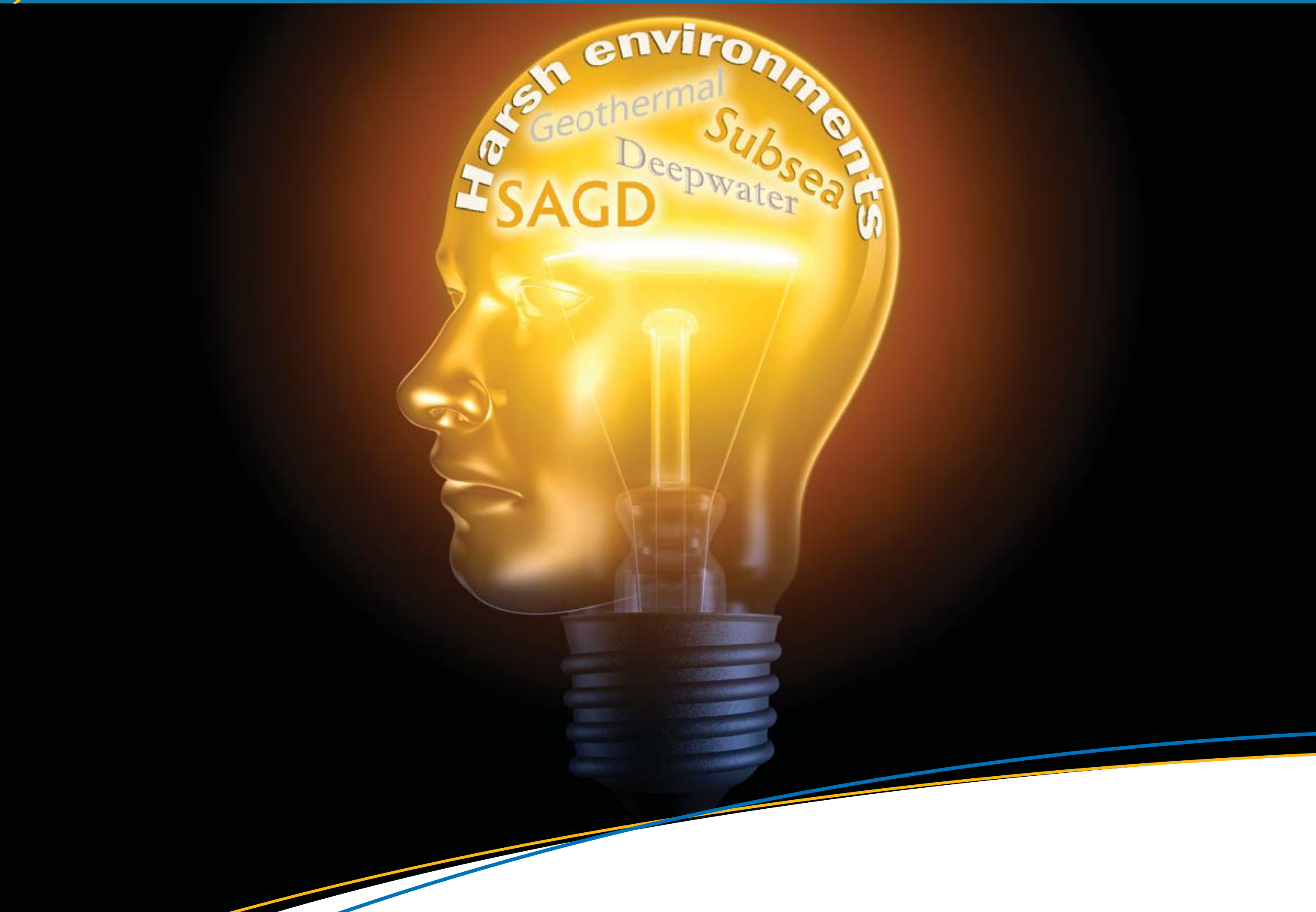

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OIL&GAS JOURNAL

International Petroleum News and Technology / www.ogjonline.com

Oil Sands Update

Forecasts moderate Alberta oil sands output growth
Exploration may resume on blocks off Bahamas
Operations needed to guide choice of amine simulator


WILLBROS

OIL&GAS JOURNAL
July 13, 2009
Volume 107.26

Oil Sands Update

Regular Features

Cover

The Connacher Oil & Gas Ltd. Great Divide SAGD project in Alberta has a 10,000 b/d design capacity. The company also recently announced that it will restart construction of the similarly sized Algar SAGD project in the same area. At Great Divide, Connacher uses trucks to haul produced bitumen to market. This issue's special report—Oil Sands Update—features articles on the Alberta oil sands that discuss the cost of carbon abatement, p. 20, the links between development and the climate, p. 22, supply and demand, p. 37, cost reductions, p. 43, and pipeline capacity, p. 56. Cover photo is from Connacher and above photo of a truck in a surface mining operation is from Suncor Energy Inc.

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General Interest — Quick Takes

Impacts estimated for hydraulic fracturing

US economic strength would be reduced by several billion dollars in the next 5 years if hydraulic fracturing was federally regulated, the second part of an American Petroleum Institute-commissioned study found.

Adopting proposals to essentially duplicate existing state regulations of a process that is helping to open up significant domestic shale gas resources would lead to job losses and a wider trade deficit, API said on July 1 as it released the second part of the study by IHS Global Insight.

The latest report looked at three scenarios: a hydraulic fracturing ban, restrictions on fluids that could be used, and the implementation of federal underground injection control (UIC) compliance regulations in addition to current state regulations.

With a total ban, the study said real gross domestic product would plunge $374 billion, or 2.3%, from the economic reference case and 2.9 million jobs, or 2%, would be lost by 2014 as a result of the 79% drop in oil and gas well completions which would result.

US GDP would drop by $172 billion, or 1.1%, and 1.3 million jobs, or 0.9%, would be lost under the study's fluid restrictions scenario. The UIC compliance approach, meanwhile, would cut GDP by $84 billion, or 0.5%, and oil and gas industry payrolls by 635,000 jobs, or 0.4% during the same period, the study said.

Economies of the leading US gas production states (Texas, Louisiana, Wyoming, and Oklahoma) would probably be hit the hardest, although many states with little or no oil and gas production would indirectly feel the effects rippling through the overall US economy, it added. Impacts would be particularly severe in states with relatively small economies such as Arkansas, Mississippi, Montana, Utah, and Virginia, it said.

The latest report follows the study's initial findings, which API released on June 9. They indicated that the number of new US wells drilled would drop 20.5%, reducing domestic gas production by about 10% from 2008 levels if Congress placed additional federal hydraulic fracturing regulations on top of existing state programs.

"Hydraulic fracturing is a safe, proven, 50-year-old technology that is critical to developing the natural gas used to heat homes, generate electricity, and create basic materials for fertilizers and plastics," said API Pres. Jack N. Gerard. "More than 1 million wells have been completed using this technology. Unnecessary additional regulation of this practice would only hurt the nation's energy security and threaten our economy."

Santos increases its CSM assets

Santos Ltd., Adelaide, increased its coal seam methane (CSM) assets in Australia with a corporate acquisition and an acreage buy in the Gunnedah basin of northern New South Wales.

The company acquired 19.9% interest in Sydney-based CSM explorer and producer Eastern Star Gas Ltd. from ESG's major shareholder Hillgrove Resources Ltd. for $176 million (Aus.).

In addition, Santos paid Gastar Exploration Ltd. $300 million for its 35% interest in several Gunnedah basin permits and production areas operated by ESG.

Santos said the Gunnedah area could be the country's second major CSM province after the Surat/Bowen Basin of eastern Queensland.

The combination of ESG and Santos permits in northern New South Wales will cover 63,000 sq km. Santos estimates a resource potential in excess of 50 tcf of gas.

Santos first entered the region in 2007 and is already undertaking a 23-well exploration program. ESG has been in the basin since 2002 and is recognized as the leading independent explorer.

ESG's Narrabri CSM joint venture's drilling program is on track to delineate 1,300 petajoules of proved and probable CSM gas reserves by yearend. ✦

Exploration & Development — Quick Takes

McMoRan finds apparent pay below Mound Point

Log-while-drilling tools indicated an encouraging 150 gross ft of resistive zones at the Blueberry Hill deep gas exploratory sidetrack well in Louisiana State Lease 340 just off western St. Mary Parish on the Gulf of Mexico shelf, said McMoRan Exploration Co., New Orleans.

McMoRan plans to deepen the well, now at 21,900 ft true vertical depth, to 24,000 ft after it resolves an undisclosed mechanical issue.

The wellsite is in 10 ft of water southeast of Mound Point oil and gas field, discovered in 1958.

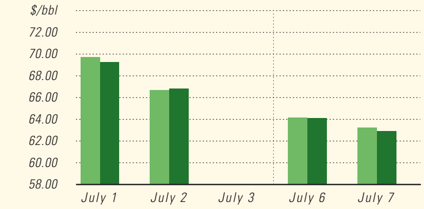
McMoRan reentered an existing well bore on Mar. 29 and sidetracked to target Miocene Gyro sands downdip on the flank of the structure encountered in the original Blueberry Hill well. It plans to run wireline logs across the resistive zones. Deepening to 24,000 ft is to evaluate other prospective sands found in the first well.

The Blueberry Hill structure, an example of McMoRan's deeper pool concept, appears to have large reserve potential and further development and exploration opportunities, the company said. It is 11 miles southeast of Flatrock, another deeper pool field with six wells capable of totaling 300 MMcfd of gas equivalent.

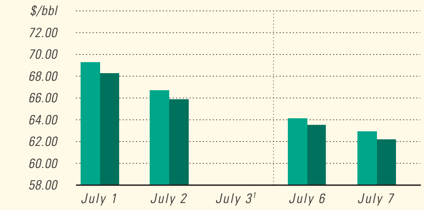
Blueberry Hill represents the deeper expression of the structural features of the shallower Mound Point field, which has produced more than 2.5 tcf of gas equivalent from multiple wells above 12,500 ft.

Industry Scoreboard

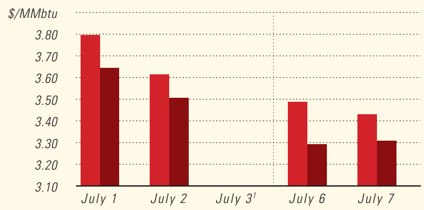
IPE BRENT / NYMEX LIGHT SWEET CRUDE



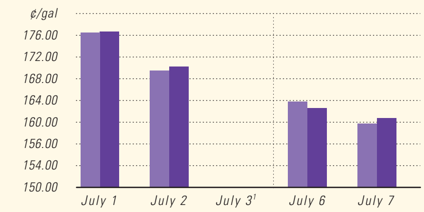
WTI CUSHING / BRENT SPOT



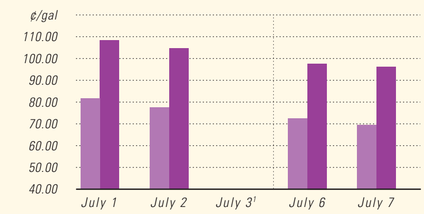
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



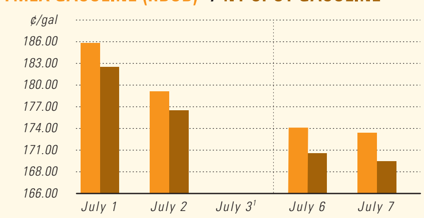
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

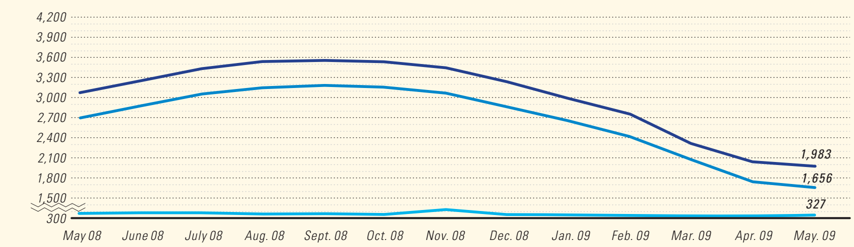
US INDUSTRY SCOREBOARD — 7/13

Latest week 6/26	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	9,169	9,087	0.9	8,954	9,021	–0.7
Distillate	3,399	3,750	–9.4	3,717	4,071	–8.7
Jet fuel	1,376	1,586	–13.2	1,384	1,559	–11.2
Residual	683	685	–0.3	568	637	–10.8
Other products	3,816	4,464	–14.5	3,953	4,499	–12.1
TOTAL DEMAND	18,443	19,572	–5.8	18,576	19,787	–6.1
Supply, 1,000 b/d						
Crude production	5,263	5,115	2.9	5,281	5,131	2.9
NGL production[2]	1,933	2,314	–16.5	1,861	2,243	–17.0
Crude imports	9,164	9,954	–7.9	9,367	9,779	–4.2
Product imports	2,572	3,355	–23.3	2,923	3,218	–9.2
Other supply[3]	1,663	1,351	23.1	1,668	1,400	19.1
TOTAL SUPPLY	20,595	22,089	–6.8	21,100	21,771	–3.1
Refining, 1,000 b/d						
Crude runs to stills	14,392	15,406	–6.6	14,392	14,879	–3.3
Input to crude stills	14,743	15,757	–6.4	14,743	15,204	–3.0
% utilization	83.5	89.5	—	83.5	86.4	—

Latest week 6/26	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	350,193	353,853	–3,660	299,776	50,417	16.8
Motor gasoline	211,238	208,905	2,333	210,857	381	0.2
Distillate	154,999	152,103	2,896	120,685	34,314	28.4
Jet fuel–kerosine	41,872	41,728	144	39,633	2,239	5.6
Residual	37,265	37,736	–471	40,000	–2,735	–6.8
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.6	23.9	–1.3	19.5	21.0	
Motor gasoline	23.0	22.8	0.9	22.6	1.8	
Distillate	45.6	44.1	3.4	29.4	55.1	
Propane	76.2	67.2	13.4	39.8	91.5	
Futures prices[5] 7/3			Change		Change	%
Light sweet crude ($/bbl)	69.36	68.85	0.51	137.63	–68.27	–49.6
Natural gas, $/MMbtu	3.80	3.87	–0.08	13.05	–9.26	–70.9

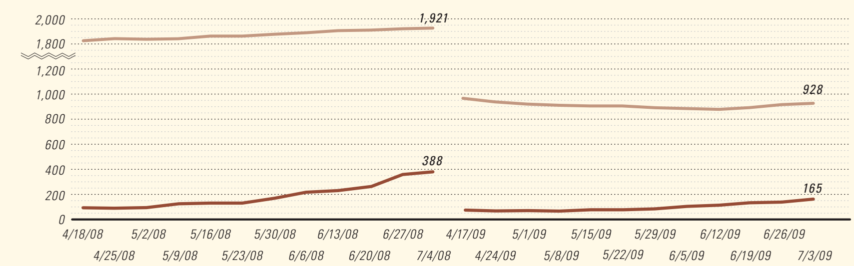
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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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McMoRan has 42.9% working interest and 29.7% net revenue interest in the Blueberry Hill well and controls 150,000 gross acres in the Tiger Shoal-Mound Point area covering federal OCS Block 310 and state lease 340. Plains Exploration & Production Co., Houston, has 47.9% working interest.

Sonatrach, GDF Suez to develop project in Algeria

Algeria's Sonatrach and GDF Suez SA of France announced plans to develop the Touat gas license in west-central Algeria, in the Timimoun basin near Adrar.

This follows an exploration and appraisal campaign that began in 2003 with seven wells. The development plan was approved by the National Agency for the Promotion of Hydrocarbon Resources (ALNAFT).

Development will start this year with gas production due on stream in 2013 and peaking at 4.5 billion cu m/year.

Sonatrach and GDF Suez will jointly operate the Touat project involving development of 10 fields in an area of 3,000 sq km on which 40 production wells will be drilled. The project also includes construction of gas collection and processing installations as well as a connection to the pipeline Sonatrach is planning to build to link fields in the area to Hassi R'Mel.

Sonatrach will be in charge of selling the gas produced. GDF Suez is one of the largest liquefied natural gas companies in the world and the largest buyer of Sonatrach's LNG.

The 10 fields are Hassi Ilatou, Hassi Ilatou Cambrien, Hassi Ilaout Nord Est, Gour Nefrat Gedinnen, Gour Nefrat Ordovicien, Bou Hadid, Bou Hadid Ouest, Oued Hamou, Oued Zine, and Sbaa.

Israel's Tamar gas may vie with LNG terminal

Noble Energy Inc., Houston, hiked its resource estimate 26% to 6.3 tcf after the Tamar appraisal well in the eastern Mediterranean off Israel "confirmed continuous high-quality reservoirs."

However, the Noble Energy group may have to compete with LNG because Israel's Natural Gas Authority last week published prequalification documents in connection with construction of an LNG receiving terminal by 2013. Noble Energy Chairman and Chief Executive Officer Charles Davidson said the group's focus is to ship Tamar gas to shore by 2012.

Tamar-2, in 5,530 ft of water on the flank of the structure 3.5 miles northeast of the Tamar-1 discovery well, considerably reduced the uncertainty in previous resource estimates, Noble Energy said. Total depth is 16,880 ft.

Tamar-2 found reservoir thickness and quality consistent with those at Tamar-1. It encountered the gas-water contact as projected in the middle reservoir and, as expected, no water contact was seen in the top reservoir.

Noble Energy obtained whole core samples in three reservoirs to assist in geologic and engineering studies needed for field development and retained a reservoir consulting firm to prepare an independent estimate of the discovered resource.

The 6.3 tcf figure is double the predrill resource estimate for the prospect (see map, OGJ, Oct. 6, 2008, p. 41).

Noble Energy said the Tamar and Dalit discoveries represent "perhaps 2 decades of future supply [of gas for Israel] based on projected needs."

Noble Energy operates the Matan license, on which Tamar was drilled, with 36% working interest. Other interest owners in the wells are Isramco Negev 2 with 28.75%, Delek Drilling 15.625%, Avner Oil Exploration 15.625%, and Dor Gas Exploration 4%.

The group is preparing to shoot 1,200 sq miles of 3D seismic over several leads on its acreage in the Levantine basin starting in the third quarter.

The government said buying LNG internationally would provide a backup to domestic supplies. It estimated maximum capacity of the LNG terminal at as much as 560 MMcfd but said early imports would likely be small because of the offshore gas discoveries, implying possible priority for Tamar and Dalit.

Israel's existing gas comes from Egypt and from fields in shallower water than Tamar.

Israel's gas demand has been rising for several years, but overall prospects for world LNG demand remain bleak (OGJ Online, July 1, 2009). ✦

Drilling & Production — *Quick Takes*

Tyrihans field off Norway starts production

StatoilHydro started production from the subsea completed Tyrihans oil and gas field in the Norwegian Sea on July 8.

Tyrihans subsea facilities, in 270 m of water, tie back to existing installations and infrastructure on the Kristin and Asgard fields in the Halten Bank area.

The field consists of two parts. Tyrihans South is an oil field with a gas cap and Tyrihans North is a gas-condensate discovery with a thin oil zone. The field lies in Blocks 6406/3 and 6407/1.

StatoilHydro estimates that the field has recoverable reserves of 186 million bbl of oil and condensate, and 41.5 million cu m of gas.

A 43-km pipeline transports the production from Tyrihans to Kristin for processing. From Kristin, the gas is transported ashore through the Asgard Transport pipeline while oil and condensate proceed to the Asgard C storage ship for onward transport by tanker.

Kristin and Tyrihans share the same operations organization.

Statoil Hydro says that Tyrihans is the largest field being brought on stream off Norway this year.

Drilling in the field, discovered in 1982-83, will continue for the next 2 years and StatoilHydro expects the field to reach a 96,000-boe/d plateau production in 2016-17.

In 2005, StatoilHydro submitted the development and operation plan to the Ministry of Petroleum and Energy, which approved the plan in February 2006.

The company installed the seabed templates in spring 2007 and began drilling wells in April 2008.

The development plan includes the installation of a subsea seawater injection facility for reservoir pressure support in summer 2010.

Statoil expects the field to continue to produce until yearend 2029.

Operator StatoilHydro holds a 58.84% interest in the field. Partners are Total E&P Norge AS 23.18%, ExxonMobil Exploration & Production Norway AS 11.75%, and Eni Norge AS 6.23%.

First deepwater circular drilling rig completed

The COSCO Shipyard Group's Qidong shipyard recently completed construction of the Sevan Driller, the world's first deepwater circular drilling rig, Sevan Marine ASA reports.

Sevan Marine owns the rig and designed it to drill to 40,000 ft and in 12,500 ft of water. The rig has a 150,000 bbl of oil internal storage capacity and a variable deckload of more than 15,000 tonnes.

Rig construction started at the COSCO Nantong shipyard in May 2007 and moved to COSCO's Qidong shipyard in April for derrick erection and final commissioning activities.

Sevan Marine says the rig, due for delivery in the third quarter, has a 6-year fixed contract with Petroleo Brasileiro SA for work in the Santos basin off Brazil.

Petrofac brings Don Southwest field on stream

Petrofac Energy Developments started oil production from two wells on Don Southwest (Don SW) in the UK northern North Sea, adding to initial output from the nearby West Don field that began in April.

Total peak production from both fields is expected to reach more than 40,000 b/d.

During the second half of 2010, the company plans to bring on stream additional production and injection wells for the second phase of the Don SW development.

Petrofac is interpreting the structure and lateral of a 60 ft oil column in the Brent formation after drilling a sidetrack to an adjacent fault block, Area H, directly south of Don SW field. This was done to investigate the northern part of the block at low incremental cost.

Amjad Bseisu, chief executive of Petrofac Energy Developments, said the company is firming up plans for a 2010 campaign to optimize Area 5/6 development "and the early indications of our success in Area H give us confidence in the prospectivity of the surrounding areas."

Don SW is an oil field comprising 450 ft thick Brent sequence sandstones, as producing in the nearby Thistle and South Magnus fields. The under-saturated oil is held in a combination of dip and fault traps at a depth of 11,000-11,500 ft.

Petrofac operates the block with a 60% interest, alongside Valiant Petroleum which has a 40% interest.

West Don field is on Blocks 211/18a West Don Area and 211/13b was developed via the floating production vessel, Northern Producer, and two production wells. The first tanker shipment of 472,000 bbl of oil from the West Don field has been delivered to a terminal in Rotterdam. Petrofac said, "The second production well and the injection well on West Don are expected to be brought on stream in the early part of the second half of 2009, with the injection wells on Don SW following in the latter part of year."

Peak production from West Don is expected to reach 25,000 b/d and was a fast track initiative; it came onstream less than 1 year from receiving field development program approval.

Oil export from the Northern Producer floating production facility will take place initially via offshore tanker, switching to pipeline export via a subsea tie-back to existing infrastructure.

Petrofac Energy Developments operates west Don with Valiant Petroleum, Nippon Oil Exploration and Production (UK) Ltd., Stratic Energy, and First Oil.

KNOC acquires riserless mud recovery technology

Korea National Oil Corp. (KNOC) signed a $9 million drilling contract with AGR Drilling Services to use its riserless mud recovery system technology off Sakhalin Island later this year and in 2010.

AGR Drilling, part of AGR Group ASA at Straume, Norway, said its technology would enable KNOC to return drilling fluids and cuttings topside without a riser system and reduce the impact on the environmentally sensitive area.

This is the second time AGR Drilling Services will be supporting drilling operations in the Pacific region.

KNOC has different blocks in Russia: Tigil, Icha, and West Kamchatka. Tigil block is off the Kamchatka Peninsula and covers 3,264 sq km. KNOC and its partners are required to shoot 2D seismic, as well as drill two exploration wells by 2010.

Icha is an onshore block spanning 3,100 sq km and is near Tigil. KNOC and its partners will shoot 2D seismic and drill one exploration well during 2010.

KNOC is exploring the West Kamchatka block in the Okhotsk Sea in partnership with OAO Rosneft. This acreage covers 62,680 sq km in less than 300 m of water.

Last year it shot 2D and 3D seismic and drilled one exploration well. Its operations are controversial as this block is in an area that is one of the world's richest producers of salmon and hundreds of other aquatic species. ✦

Processing — *Quick Takes*

Total to sell Dutch refinery stake to Lukoil

Total SA has exercised its preemptive rights to acquire a 45% share in the 147,000-b/d Vissigen refinery in the Netherlands from Dow Chemical and entered an agreement to sell the stake to Lukoil.

Total owns 55% of the refinery. It said the sale to Lukoil is contingent on acceptance of the deal by the "competent authorities," including the European Commission's competition regulators and, according to a Total spokesman, workers' committees in France and the Netherlands.

A purchase price of $725 million reported in the Russian press was not confirmed by Total.

Valero Energy Corp. earlier had agreed to buy the Dow Chemical interest for an enterprise value estimated at $725 million.

Lukoil supplies around 30% of the crude oil for Total's West European refineries.

Start-up delayed for Kuwait styrene unit

Start-up of Kuwait Styrene Co.'s ethyl benzene styrene monomer unit in Kuwait has been delayed 4-8 weeks by a technical problem with an intermediate storage tank used in the production of styrene monomer.

Officials said they do not know how long the start-up may be delayed, pending a technical assessment of the tank. The unit expected to begin commercial operations within a few days. It was due to start up in the second quarter, according to previous company statements.

KSC, a major producer of olefins in Kuwait, is in contact with customers and has developed plans to help mitigate any production shortfall due to the delay, officials said.

The unit is within Equate Petrochemical Co.'s complex in the Shuaiba Industrial Area. The KSC plant is designed to produce 450,000 tonnes/year of ethyl benzene and 500,000 tonnes/year of styrene monomer. Those facilities will be operated by Equate, a firm largely owned by Petrochemical Industries Co. and Dow Chemical Co. KSC is a joint venture of Dow Chemical and government-owned Kuwait Aromatics Co. ✦

Transportation — *Quick Takes*

Tangguh LNG sends out first cargo

Indonesia's Tangguh LNG project, the country's third LNG center after Bontang and Arun, lifted its first cargo on July 6, according to operator BP PLC. The liquefaction plant is in Papua Barat.

The first cargo marks start-up of the project, slightly more than 4 years after its final approval by the Indonesian government March 2005. The cargo, aboard the Tangguh Foja, sailed for POSCO's LNG regasification terminal in Gwangyang, South Korea.

Tangguh consists of the development of six gas fields in the Wiriagar, Berau, and Muturi production-sharing contracts in the Bintuni area of Papua in eastern Indonesia. Gas produced from two normally unmanned offshore platforms is fed via 22-km pipelines to two onshore liquefaction trains, each with a production capacity of 3.8 million tonnes/year of LNG.

Train 1 began LNG production in mid-June, said BP, producing the LNG for the first cargo, and Train 2 will begin later this year.

BP Indonesia (37.16% interest) operates Tangguh as a contractor to the Indonesian oil and gas regulator, BPMigas. Other partners in the project are MI Berau BV (16.3%), CNOOC Ltd. (13.9%), Nippon Oil Exploration (Berau) Ltd. (12.23%), KG Berau/KG Wiriagar (10%), LNG Japan Corp. (7.35%), and Talisman (3.06%).

The project has long-term contracts to supply 2.6 million tpy of LNG to China's Fujian terminal, 1.15 million tpy to K-Power and POSCO in South Korea, and a flexible contract to supply up to 3.7 million tpy to Sempra's LNG regasification terminal in Baja California, Mexico.

Main engineering contractors for the Tangguh project's onshore infrastructure are the KJP consortium: Kellogg, Brown & Root (through its subsidiary PT Brown & Root Indonesia), JGC Corp., and PT Pertafenikki Engineering. Lead contractor for offshore and subsea construction was Saipem.

Enterprise opens central treating facility

Initial volumes of natural gas have begun flowing into the new central treating facility (CTF) in Rio Blanco County, Colo., owned and operated by Enterprise Products Partners LP. The facility was completed in fourth-quarter 2008.

Located about 8 miles south of Enterprise's recently expanded Meeker gas processing complex, the CTF can handle as much as 200 MMcfd and handles production from ExxonMobil's properties in nearby Piceance basin. Production from those, according to the Enterprise announcement, is currently running about 100 MMcfd.

Michael A. Creel, Enterprise president and chief executive officer, said the facility provides the necessary services to support ExxonMobil's Piceance project and "complements our recently completed Meeker II expansion." That expansion doubled gas processing capacity at the complex.

The CTF treats natural gas to remove impurities then compresses that treated gas for transportation to Meeker. There, Enterprise can use its standalone 200 MMcfd dewpoint-control plant for processing or route the stream through one of the larger cryogenic processing units.

Completion of the Meeker Phase II expansion brought cryogenic processing capacity to 1.5 bcfd and allows extraction of as much as 70,000 b/d of NGL, said the Enterprise announcement. Separation of NGLs into ethane, propane, butanes, and natural gasoline renders the residue-gas stream acceptable for delivery into one of several interstate transmission pipelines accessible to producers through the White River Hub.

That hub is jointly owned by Enterprise and Questar Pipeline Co. Through Enterprise's Mid-America Pipeline and Seminole systems, the extracted NGLs can be delivered to the partnership's Hobbs and Mont Belvieu, Tex., fractionation facilities.

Meeker and the new CTF are part of a 30-year midstream services agreement Enterprise has with ExxonMobil, which has estimated 45 tcf of potential natural gas on its acreage in the Piceance basin, said Enterprise.

Total gas production among all the producers in the basin, which covers more than 6,000 square miles, currently exceeds 1.5 bcfd from more than 6,000 wells, said the company. Additionally, production has been growing at about 23%/year over the past 6 years and continues to support sustainable drilling activities.

Authorization pulled for GDF Suez terminal

The Marseille Administrative Court rescinded the authorization granted by regional executive authorities for operation of the GDF Suez methane terminal under construction at Fos-sur-Mer.

The terminal was undergoing final tests before its launch at year-end. Authorization was rescinded after an association for protection of the coastline pointed to the absence of certain documents—including a seismic survey—from the public inquiry process.

GDF Suez said it would appeal. Meanwhile, as the reauthorization process will be lengthy, the company will request provisional authorization since "the project is strategic for southern France," officials reported. ✦

Letters

Energy crash landing

As one reads the editorials of June 1—on the mind-numbing subsidies for renewable energy—and June 9—on the costs of "cap and trade" and "energy reform that will asphyxiate itself with unreasonable ambition and government excess," plus the note in the commentary on the likelihood of any benefits being allocated "on the basis of political favoritism," a sense of absolute gloom and doom emerges (OGJ, June 1, 2009, p. 18; June 8, p. 18). It would seem that this administration is forcing our energy system towards a crash landing of unprecedented proportions.

Today, we hear much about the danger of fossil fuels, particularly coal. The alarmists, in their efforts to do to coal what they have done to nuclear energy, have now painted coal as the pariah of all energy sources. Oil is not treated much better.

I have recently written on an analogy between a crash landing in the desert and in our energy situation today. The title is "The Flight of the Phoenix Revisited." The subtitle is "We Can Live with a Fossil Fuel World–Oil, Gas, Coal and Shale Oil." This essay is available at www.co2science.org/articles/V12/N16/EDIT.php.

This essay is a fairly complete situation review of most energy sources. Conclusions reached include:

- While alternative energy sources can make a contribution, they will not be the solution to our current crisis; we will be using fossil fuels for decades to come.
- The pathway to price security is to reduce our call on global oil via a boost in our conventional supplies of domestic oil and gas via an expanded use of coal, via a start on shale oil, via an improvement in electric vehicles and their necessary electric supply, and via more efficiency and conservation.
- The massive expansion of nuclear power proposed by Sen. John McCain (R-Ariz.) is seen as desirable but highly unlikely.
- The most encouraging research area is the development of high energy-density batteries.

• The most discouraging commercial area is the incredible support and subsidies for corn-based ethanol.

• The climate change situation in regards to fossil fuel use, is manageable, and the need to move to a carbon-constrained society is premature at best.

• The environmental situation with coal is manageable, a judgment based in part on my lifetime exposure to coal and in part on the improvements in emissions control over the past 40 years.

This essay also reviews, as food for thought, my rather detailed, 76-year exposure to coal dust, heavy oils, and toxic chemicals and leads to the question: Could the nightmare painted on fossil fuels just be overstated a bit?

Gerald T. Westbrook
Houston

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.

2009

JULY

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

Petroleum Association of Wyoming (PAW) Annual Meeting, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: suz@pawyo.org, website: www.pawyo.org. 18-19.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@

Calendar

gita.org, website: www.gita.org/ogca. 14-16.

Turbomachinery Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website:http://turbolab.tamu.edu. 14-17.

Annual IPLOCA Convention, San Francisco, +41 22 306 02 30, +41 22 306 02 39 (fax), e-mail: info@iploca.com, website: www.iploca.com. 14-18.

Polar Petroleum Potential 3P Conference, Moscow, (918) 584-2555, (918) 560-2665 (fax), website: www.aapg.org. 16-18.

Annual Energy Policy Conference, Oklahoma City, (202) 580-6532, (202) 580-6559 (fax), e-mail: info@energyadvocates.org, website: www.energyadvocates.org. 20-22.

ADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

SPE Eastern Regional Meeting, Charleston, W.Va., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

ERTC Sustainable Refining Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 28-30.

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

Unconventional Gas International Conference & Exhibition, Fort Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 29-Oct. 1.

ERTC Biofuels+ Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 30-Oct. 2.

OCTOBER

Interstate Oil and Gas Compact Commission Annual Meeting (IOGCC), Biloxi, Miss., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

SPE Annual Technical Conference and Exhibition, New Orleans, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-7.

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 6-8.

Kazakhstan International Oil & Gas Exhibition & Conference (KIOGE), Almaty, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-9.

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale/. 19-23.

Oil and Gas Transportation in the CIS and Caspain Region Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 20-22.

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

North African Oil and Gas Summit, Tunis, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

NOVEMBER

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 5.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO2symposium.com. 5-6.

Sulphur International Conference and Exhibition, Vancouver, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.sulphurconference.com. 8-11.

Gas Turbine Users International (GTUI) Annual Conference, Calgary, Alta., +9714 804 7738, +9714 804 7764 (fax), e-mail: info@gtui.org, website: www.gtui.org. 8-13.

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Digital E&P Event, Houston, (646) 200-7444, (212) 885-2733 (fax), e-mail: cambrosio@wbresearch.com, website: www.digitaleandp.com. 9-11.

Petroleum Association of Wyoming (PAW) Annual Oil & Gas Statewide Reclamation Conference, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: cheryl@pawyo.org, website: www.pawyo.org. 10.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 10-12.

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

DECEMBER

Refining and Petrochemicals in Russia and the CIS Countries Annual Meeting, Amsterdam, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 1-3.

World LNG Summit, Barcelona, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), e-mail: info@thecwcgroup.com, website: www.thecwcgroup.com. 1-4.

Emerging Unconventional Resources Conference & Exhibition, Shreveport, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.emergingresourcesconference.com. 8-10.

PIRA Understanding Natural Gas and LNG Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 14-15.

PIRA Understanding Global Oil Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 16-17.

2010

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition Co-located with Pipeline Rehabilitation and Maintenance, Cairo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Co-located with Oil & Gas Maintenance Technology, Cairo, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pipeline-rehab.com. 19-21.

API Exploration and Production Winter Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222, website: www.api.org. 25-29.

The European Gas Conference and Annual Meeting, Vienna, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 26-28.

Annual Gas Arabia Summit, Abu Dhabi, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. Jan. 31- Feb. 3.

The biology of oil

Steven Poruban
Senior Editor

It's always interesting to discover the ways in which various scientific disciplines intertwine with the oil and gas industry. While traditional research and development is being conducted by scientists specializing in petroleum biology to enhance efforts of extracting and processing hydrocarbons, other R&D companies pour their efforts into finding ways to bypass hydrocarbons completely, opting to produce a "greener," more-renewable source of oil.

Microbiology

Abdulmohsen A. Al-Humam, a member of the biotechnology group at Saudi Aramco's research and development center, has been working on methods to control microorganisms that cause problems in water-injection systems and oil-field reservoirs.

Recent research by Al-Humam could have far-reaching effects on oil production in Saudi Arabia, Aramco reports. His thesis for earning a PhD in petroleum microbiology, "Effects of Nitrate on Mixed Bacterial Communities in an Oilfield Water Distribution System," sheds light on the processes that control microorganisms at oil facilities.

In a recent company publication, Aramco described the issue: "Water is injected into oil reservoirs to keep the pressure high, boosting production. The reservoirs are also prime habitats for sulfate-reducing bacteria (SRB), a diverse group of microorganisms that decrease the level of sulfate in minerals such as oil. But as they reduce sulfate, they produce hydrogen sulfide (H_2S), a highly toxic substance causing one of the petroleum industry's biggest problems, souring. And that lowers the economic value of oil and carries major safety hazards."

Al-Humam says, "Unfortunately, for years, industries disregarded the concept of biological souring of oil field reservoirs. This resulted in production facilities being designed and built without consideration of the long-term effects that microorganisms might have on the operation and maintenance of these facilities."

Aramco says that Al-Humam's research "offers a new, alternative approach to controlling SRB levels through repeated injections of nitrate."

Al-Humam's study was conducted in two parts: first in laboratory experiments and then in a field trial in Aramco's Hawtah oil field. "The trial showed that injecting nitrate into the water-distribution system limited SRB activity and H_2S production, was 43% more cost-efficient than other methods, and improved well operation by 12-15%," Aramco said.

Al-Humam's research was presented at the Reservoir Microbiology Forum, held by the British Energy Institute in London, and at the Corrosion Conference held by NACE International. EI's next RMF is slated for Nov. 24-25 in London.

Oil from algae

Another company is sidestepping hydrocarbons in its development of a renewable form of energy from an unlikely biological source.

OriginOil Inc. is developing a breakthrough technology that will transform algae, "the most promising source of renewable oil," into "a true competitor to petroleum," the company says. The company's web site (www.originoil.com) contains videos of the process.

OriginOil explains: "Much of the world's oil and gas is made up of ancient algae deposits. Today, our technology will produce "new oil" from algae, through a cost-effective, high-speed manufacturing process. This endless supply of new oil can be used for many products such as diesel, gasoline, jet fuel, plastics, and solvents without the global warming effects of petroleum."

The benefits of the process, OriginOil says, are numerous. It says: "Other oil-producing feedstock such as corn and sugarcane often destroy vital farmlands and rainforests, disrupt global food supplies, and create new environmental problems." Their technology, says the Los Angeles-based company, "is targeted at fundamentally changing our source of oil without disrupting the environment or food supplies," adding, "Instead of drilling for old oil, we can now manufacture clean, new oil, anytime and anywhere, delivering a revolutionary breakthrough to the world."

The search continues

Interesting, all of it. Of course, the most important part of seeking out new ways to safely extract oil and gas as well as developing alternative energy sources remains the search itself. It's been reported time and time again that the world's energy will need to come from many, many sources. So, let the search continue. ✦

Four 58-MW Rolls-Royce Trent GTGs Available for Immediate Delivery

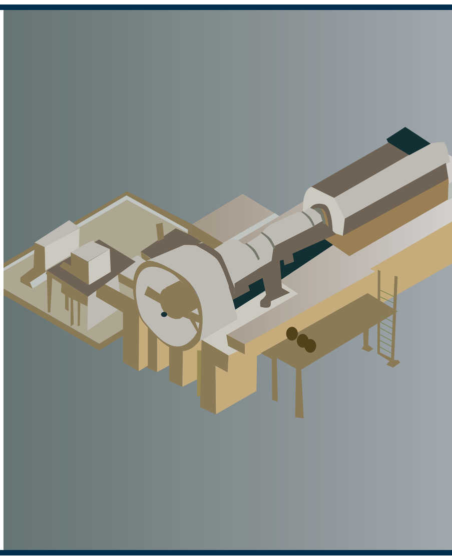
The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.



Unused GE D11 HP/IP Turbine Assembly Available for Immediate Sale

All parts professionally stored in Pensacola, Florida

Unused GE D11 HP/IP turbine assembly and other miscellaneous parts including LP casings and 304-MW generator stator now available for immediate sale.

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

Solar Centaur 40 T4701S Turbine Generator Package with approximately 60,000 accumulated hours at 50% load. Package was in service from 1999 until August 2007. Engine is BACT compliant with OEM 25 ppm Nox/50 ppm CO guarantee. Operates off SAB-type Ideal generator rated at 3500 kW, 4375 kVA and 13,800 volts at 60 Hz. Miscellaneous equipment includes inlet air filtration and simple exhaust systems, and auxiliary control console with start/stop/sync/control.

Williams.

For Info or Pricing
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Editorial

Low-carbon fuel problems

Producers in Alberta's oil sands region rightly worry about one of the worst ideas in the rich stew of energy-policy poison now at high boil in the US.

The idea is the low-carbon fuel standard (LCFS). By itself, a carefully implemented LCFS might hold promise as a way to trim emissions of carbon dioxide. Together with the heavy, indirect taxation of fossil energy that probably will be enacted, however, it represents stifling overkill. And the recent US record makes careful implementation most unlikely.

The 1,428-page American Clean Energy and Security Act, which the House passed June 26 before anyone had any grasp of everything it contained, originally included an LCFS. That the passed bill does not is a hopeful sign. But the Senate has yet to act. And California implemented an LCFS in April and savors its status as national leader in the establishment of ruinous energy policy. A group of states in the US Northeast is working on a regional LCFS and hope to have a preliminary agreement in place by yearend.

Reason to worry

Oil sands producers, therefore, have reason to worry. In its LCFS regulation, California excludes oil-sands crude from the "basket" of fuels available in the state, which will benchmark declining "carbon intensity" targets. The Canadian Association of Petroleum Producers objects. "Singling out Canada's oil sands was unnecessary and inappropriate," it said in response to California's move. "On a life-cycle basis, Canadian oil sands crude compares favorably with many other crude oils currently supplying California, including some domestic California crude oils."

Alone, California's disproportionate regulation won't hurt Alberta's oil sands industry. The state receives only about 27,000 b/d of oil from Canada, some of it originating in the oil sands. The concern north of the border is that California will set a pattern of discrimination against what has been called the "dirty oil" from Alberta's rich deposits of bitumen. It's a concern that began with an ambiguous section of the Energy Independence and Security Act of 2007 banning imports by federal agencies of fuels with above-average life-cycle emissions of CO_2. Since then, demonization of "tar sands" has been a popular ploy of the environmental groups that back Democratic leaders in Congress and the White House.

Emissions associated with fuels from oil sands are, in fact, too easily exaggerated. Studies are showing that, from production to consumption, average CO_2 emissions from a given quantity of fuel from oil sands exceed those of average conventional oils by 10-20% (see story, p. 20). That's far less than what environmentalist propaganda suggests.

In California and elsewhere, LCFS regulation has other problems. Large among them is the assumption that regulators can measure life-cycle emissions with reasonable precision. They can't. Inevitably, life-cycle assessment is more political than scientific. Prominent evidence of this is ethanol promoters' campaign to exempt land-use changes in assessments of emissions associated with their favorite fuel additive.

Indeed, LCFS regulation largely assumes the displacement of hydrocarbon fuels by biofuels, which are presumed to have life-cycle emission advantages. But those advantages are proving to be illusory, especially in analyses that account for the indirect effects of expanding agriculture. Hence the ethanol lobby's latest crusade.

Bad business

What's more, biofuels have become bad business for everyone except grain farmers. Refiners are buying ethanol plants out of bankruptcy at fire-sale prices to secure supply with which to meet blending mandates. Yet in its announcement about implementation of the LCFS in April, California's Air Resources Board bragged about the need for 25 new biofuel facilities and the associated creation of 3,000 jobs. Hello? Without subsidization likely not to be forthcoming from a bankrupt state government, who will build the things?

The formulaic approach of LCFS regulation creates the impression of serious governance. The government sets a target for cutting life-cycle emissions and lets the market bring forth essential technologies. Inevitably, however, the target is arbitrary. Inevitably, work toward it reflects politics rather than commerce. So, inevitably, LCFS proves to be yet another costly, underperforming environmental gesture that mainly encourages Canadian producers to sell oil in Asia. ✦

Study estimates costs of CO_2 emission controls on oil sands

New controls on emissions of greenhouse gases will raise the costs of petroleum supplied from oil sands by amounts that depend on the extent of regulation and on progress in abatement technologies.

The extra emissions associated with oil sands have attracted intense environmental scrutiny and spawned efforts to limit consumption of products derived from bitumen.

According to a report on the Canadian oil sands published in May by the Council on Foreign Relations Center for Geoeconomic Studies, the average, life-cycle greenhouse gas emissions associated with a barrel of oil sands crude exceed those from the average barrel of oil consumed in the US by about 17%.

The study, by Michael A. Levi, CFR David M. Rubenstein senior fellow for energy and the environment, projects costs to producers and refiners of conventional and unconventional crude oil at various prices of emitted carbon.

Comparing emissions

The extra emissions associated with oil sands come mainly from production and upgrading, Levi points out.

The average emissions from these operations in the oil sands are nearly three times those of the average barrel of oil consumed in the US.

But emissions vary among oil sands projects. Levi cites a recent RAND study that found greenhouse-gas emissions from production and upgrading of oil sands range from 70 kg/bbl to 130 kg/bbl—10-20% more than the average barrel of oil consumed in the US.

Emissions from oil sands would increase with a shift in process fuels from natural gas to coal or raw bitumen; they would decrease with technological improvements.

"The latter trend has recently dominated," Levi says.

The analyst also points out that average emissions vary with crude type (Table 1).

He says the extra greenhouse-gas emissions associated with Canadian oil sands relative to conventional oil at the current production rate, about 1.2 million b/d, represent about 5% of Canada's total emissions, 0.5% of US emissions from energy use, and 0.1% of global emissions.

If production increases as expected with no improvement in per-barrel emissions, the contribution to Canadian emissions will triple by 2030. But the increment relative to US and global emission will still be minor.

If policies slash emissions from other sources to the extent necessary to meet ambitious goals set to abate global warming, however, "the relative prominence of the oil sands would greatly increase," Levi says.

Increases in emissions related to an expected rise in oil sands production to a plateau of 4.2-4.3 million b/d in 2030, coupled with emissions cuts in the US and Canada of 80% by 2050, would make oil sands responsible for about 10% of US emissions and nearly all of Canada's emissions at mid-century.

"Oil sands' emissions will thus be critical to deal with in the long term though not as important in the immediate future," Levi says.

The cost

A central question thus is the cost of lowering greenhouse-gas emissions from oil sands production and upgrading.

Levi estimates costs to producers of oil sands and conventional oil, assuming no abatement measures, based on carbon prices of $20/ton, $50/ton, and $100/ton of carbon dioxide equivalent (CO_2e) (Table 2).

A carbon price of $20/ton of CO_2e is about the level in effect in Europe and what is expected to result from a cap-and-trade scheme or carbon tax in the US. The price probably would rise toward $50/ton of CO_2e in 2020-30 and continue to rise after that.

Levi points out that projected carbon costs for oil sands are small relative to the expected price of oil and says, "This is in stark contrast, for example, with coal-fired power, whose cost would increase sharply even for modest carbon prices."

He adds, "Carbon costs could affect production and pricing at the margin, and very high carbon prices in the near term could have much larger impacts."

Average per-barrel emissions relative to average barrel consumed in US*

Table 1

Source	Production, upgrading, and transport to refinery	Refining and finished fuel transport	Total well-to-tank	Total well-to-wheels
	%			
Canada (oil sands)	252	135	185	117
Venezuela (bitumen)	221	129	168	114
Nigeria	300	57	162	113
Mexico	96	159	131	106
Angola	202	69	125	105
Kuwait	70	135	107	101
Iraq	76	122	102	100
Venezuela (conventional)	66	129	101	100
Canada (conventional)	88	107	98	99
Ecuador	89	103	97	99
Saudi Arabia	63	119	95	99
Domestic	62	82	73	94
Algeria	95	46	68	94

*Based on average for US imports from each source. Emissions in first column normally occur in country where crude is produced. Emissions in second column are much more likely to occur in the US.
Source: Michael A. Levi, Council on Foreign Relations, based on numbers for diesel in Gerdes, Kristen J., and Skone, Timothy J., Consideration of Crude Oil Source in Evaluating Transportation Fuel GHG Emissions, National Energy Technology Laboratory, 2009

Average carbon cost to producers*

Table 2

Source	Carbon price ($/ton of CO_2 equivalent) 20	50	100
	$/bbl		
Canada (oil sands)	2.21	5.53	11.07
Canada (conventional)	0.52	1.29	2.58
US	0.36	0.90	1.80

*Assuming no abatement measures. Costs vary among projects. Actual compliance costs may be lower.
Source: Underlying emissions figures based on source in Table 1

Average carbon cost to producers and refiners*

Table 3

Source	Carbon price ($/ton of CO_2 equivalent) 20	50	100
	$/bbl		
Canada (oil sands)	3.96	9.90	19.81
Venezuela (bitumen)	1.55	3.87	7.75
Nigeria	0.69	1.72	3.44
Mexico	1.92	4.81	9.61
Angola	0.83	2.07	4.14
Kuwait	1.63	4.08	8.16
Iraq	1.47	3.67	7.34
Venezuela (conventional)	1.55	3.87	7.75
Canada (conventional)	1.95	4.89	9.77
Ecuador	1.25	3.12	6.23
Saudi Arabia	1.44	3.61	7.22
Domestic	1.57	3.93	7.86
Algeria	0.56	1.40	2.80

*Assumes no abatement measures. Carbon pricing assumed to apply only inside the US and Canada. Product assumed to be diesel; figures would change little for gasoline.
Source: Underlying emissions figures based on source in Table 1

Levi also estimates the average carbon cost to producers and refiners for a range of crude oils, assuming that Canadian and US producers face carbon costs throughout the operational chain and that others face carbon costs for refining and final distribution in the US.

He notes that while the refining increment roughly doubles the cost of Canadian sources, it adds to other oils as well.

"Whether this extra cost will be absorbed by producers (through reduced production or lower profits), by refiners, or by consumers (through higher prices) depends on the finer details of refining and product markets and is extremely difficult to predict," Levi says. "The possibility that the impact of carbon pricing will be larger than what is indicated in Table 2 is, nonetheless, impossible to dismiss."

Policy recommendations

Levi made his cost observations as part of a study, The Canadian Oil Sands: Energy Security vs. Climate Change, that included policy recommendations. He said a US strategy for the Canadian oil sands that balances climate change mitigation with security interests should combine these elements:

- *Link US and Canadian cap-and-trade systems.* The aim, Levi said, should be "fair and stable carbon pricing in Canada." The US should ensure that Canada is able to provide a small number of free emission permits to oil sands producers, he said. Doing so would both lower the risk that carbon pricing would raise world oil prices and maintain incentives for oil sands producers to cut emissions.
- *Tread carefully with any low-carbon fuel standard.* Any requirement for specific cuts in average emissions from transportation fuel should not penalize oil sands, which already will carry a heavy burden of carbon costs.

"Carbon costs could affect production and pricing at the margin, and very high carbon prices in the near term could have much larger impacts."

Michael A. Levi, senior fellow for energy and the Environment, Council on Foreign Relations

• *Focus US technology support on higher-payoff areas.* Government assistance for carbon capture and sequestration (CCS) and nuclear power for oil sands "would generally not be US dollars well spent," Levi said. Government-funded innovation instead should focus on CCS for power plants, renewable fuels, transmission, and efficiency.

• *Resist the misuse of other US environmental regulations to constrain oil sands.* "So long as the oil sands are expected to face a fair and reasonable carbon price, the United States should resist attempts to use US environmental regulations to block permitting of oil sands-related pipelines or refineries on climate grounds," Levi said. Similarly, the US should not use regulations to indirectly address social and environmental effects of oil sands work in Canada. ✦

N. American strategy should link energy, climate concerns

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Canadian Association of Petroleum Producers
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Energy and climate change are important topics. And because energy production and use are sources of greenhouse gas (GHG) emissions, the two are linked.

Many activists and some policy-makers embrace an approach requiring ultimate elimination of the use of all fossil fuels. They support their replacement with renewable alternatives such as hydrogen, electricity, and biofuels.

Others believe these alternatives are merely wishful thinking. They see the alternatives as having promise for the future but nowhere near the technological readiness or affordable availability that would allow them to compete with conventional fuels in the marketplace.

As is often the case, reality lies somewhere between these extremes and encompasses both energy sources and worldwide energy demand. North America's oil sands reserves are squarely in the middle of the debate.

Global energy demand is increasing rapidly and shows no signs of declining. That is actually a good sign, as energy fuels economic growth. The exploding growth of emerging economies such as China and India and the desire of their citizens for the quality of life long taken for granted by Western nations guarantee more energy use, not less.

A study last month by Cambridge Energy Research Associates (CERA), Growth in the Canadian Oil Sands: Finding the New Balance, projects that by 2035 global oil demand will reach upwards of 97 million b/d in its lowest growth scenario. In 2008 the total was 85 million b/d.

"Even in a world of relatively slow demand growth, new supplies of oil will be needed, especially to meet demand for greater mobility among those entering middle income levels around the world and to offset declining production in existing oil fields," the CERA study says.

"Alternative forms of energy, such as biofuels, wind, and solar power, will play a growing role in satisfying higher demand, but so will fossil fuels, including oil," adds the report. "Indeed, all forms of energy—as well as greater efficiency—will be needed to deliver and support higher living standards around the world."

In the US, where energy demand is growing more slowly, the Energy Information Administration estimates usage will still be 11% more in 2030 than in 2007.

In any growth scenario, in North America and around the world, we're going to need all the energy resources we can get. And while new sustainable and renewable fuels will play an increasingly important role, experts agree that fossil fuels will constitute the majority of our energy supply portfolio long into the foreseeable future. We need to develop potential new energy sources and intelligently use the ones we already have. This includes conventional and unconventional oil and gas, coal, and nuclear, plus renewable sources.

COMMENT

"We need to develop potential new energy sources and intelligently use the ones we already have."

David Collyer, president Canadian Association of Petroleum Producers

Catherine Reheis-Boyd executive vice-president and chief operating officer, Western States Petroleum Association

Oil sands story

The story of the oil sands is a story about people and communities. When industry talks about the economic benefits of the oil sands, it does so at the risk of being accused of downplaying the importance of environmental issues. But, clearly, Canadians and Americans expect oil sands development to occur responsibly, and the oil sands industry is focused on meeting those expectations without sacrificing jobs, economic benefits, or strategic energy supply advantages.

The CERA report also highlights the direct link between economic growth and the need for continuous improvement in environmental performance. Can higher environmental standards be achieved? The record shows that the industry has a strong track record, including a 38% reduction in greenhouse gas emission intensity since 1990, 80–95% recycle rate on process water, use of undrinkable water from deep salty aquifers for new oil sands projects, ongoing reclamation of project sites, as well as a suite of emerging technologies that promise to further reduce energy input requirements and subsequent emissions as well as improve water management.

It's also worth noting that Alberta was the first jurisdiction in North America to implement a carbon pricing system ($15/tonne of CO_2 levy into a technology fund), and it has created a market for offsets. In addition, Alberta last year established a $2 billion fund to stimulate early development of carbon capture and sequestration projects.

The stakes are high for both the US and Canada. Numerous reports, including CERA's recent report, point to the potential for significant growth in Canada's share of US oil imports. But the study also notes that "a key challenge for continued cooperation is the development of a common framework for regulating greenhouse gas emissions."

Greenhouse gas emissions from oil sands have become a favorite target for critics, but considered in context, oil sands produce 5% of Canada's total greenhouse gas emissions, or 0.1% of the world's total emissions. And recent studies indicate that oil sands crudes are comparable in GHG emissions per barrel on a full life-cycle basis to average crude oils in the US.

Canada can provide the US with a blend of both conventional oils—currently about half of the nation's production—and oil sands that is similar to the basket of imported oil from other nations. Oil sands would no longer incorrectly be categorized as exceptional in terms of GHG emissions. Meanwhile, according to CERA, "the 'average' conventional barrel imported into the United States may become heavier over time as high-quality light crude becomes scarcer."

Developing strategy

That is not an argument for the status quo. On the contrary, the link between understanding GHGs, improved environmental performance, and energy security is critical to developing a strategy that meets increased demand and economic growth while responsibly increasing the overall energy supply mix.

Canada has enormous reserves of crude oil in oil sands—an estimated 173 billion bbl—second only to Saudi Arabia. Currently, Canada's oil sands produce more than 1 million b/d, with production expected to grow by about 3 million b/d by 2020.

It's only logical that the US and Canada explore the energy opportunities inherent in oil sands development. The countries are friendly neighbors that enjoy mutually beneficial trade relations and a common commitment to the environment.

Even with heightened awareness of and a commitment to reducing greenhouse gas emissions, the world is moving toward more, not less, energy use. While it's important that we diversify our energy portfolio with the introduction of new, less carbon-intensive fuels, we also need to use those we already have.

This should and can be done in an environmentally sensitive manner while providing the energy necessary to keep the modern world running. Oil sands are an important part of the equation that will allow a smooth journey to the energy world of the future while adequately fulfilling our needs on the way there. Their inclusion in our energy supply strategy is critical.

The US and Canada share the largest energy trading relationship in the world. Canada is currently the largest supplier of energy to the US, including 18% of American petroleum imports and 82% of American natural gas imports. It is in the best interest of both countries to ensure the energy trading relationship remains intact and vital. ✦

IEA: World oil demand to reach 89 million b/d by 2014

The latest forecast by the International Energy Agency states that global oil demand will rise 0.6%/year during 2008-14, pushing demand to average 89 million b/d in 2014 from 85.8 million b/d last year.

In its Medium-Term Oil Market Report, IEA bases its outlook on the International Monetary Fund's economic forecast, which sees global economic activity gradually rebounding by nearly 5%/year from 2012 onwards.

Developing countries, those that are not members of the Organization for Economic Cooperation and Development, will drive oil-demand growth, while oil consumption within the OECD will decline over the forecast period, IEA said.

Also, transportation fuels will drive the growth in oil demand. In non-OECD countries, demand for transportation, boiler, and industrial fuels will all rise at a relatively rapid pace, but distillate will be the growth drivers, followed by LPG, naphtha, and gasoline.

Meanwhile, within the OECD, demand growth of motor gasoline, jet fuel, and diesel after 2009 will be modest and insufficient to offset declines in demand for heating oil, residual fuel oil, and industrial feedstocks, according to the report.

North America

IEA expects that oil demand in North America will decline to average 23.7 million b/d in 2014 from 24.3 million b/d in 2008.

The combination of severe economic recession, changing behavioral patterns triggered by the sharp rise in oil price in the first half of 2008, and a new administration in the US that is intent on improving overall efficiency and reducing carbon emissions suggests that a return to past high growth rates in gasoline demand is unlikely, despite an expected economic recovery that could boost discretionary driving again, the agency said.

During 2008-14, IEA forecasts that naphtha demand in North America will decline on average 8.6%/year, as petrochemical activity declines in the US and Canada as other, more-competitive petrochemical production areas emerge. Growth in demand is expected in Mexico, but from a low base.

Gasoline demand in North America will climb 0.6%/year to average 11 million b/d in 2014. And demand for jet fuel and kerosine in the region will rise by the same rate to reach an average 1.8 million b/d, as economic recovery boosts air travel, offsetting efficiency gains in aircraft fleets and airline operations.

Demand for gas oil in North America will be unchanged over the period, averaging 5 million b/d, while declining use of fuel oil for power generation is expected to cause demand to shrink 8.5%/year to average 700,000 b/d in 2014.

OECD Europe, Asia

IEA's forecast calls for oil-product demand in OECD Europe—led by France, Germany, the UK, Spain, and Italy—to decline 1.3%/year to average 14.1 million b/d in 2014. Demand will rise for jet fuel, decline for naphtha, gasoline, and fuel oil, and be unchanged for gas oil.

Demand in these countries is already falling due to structural reasons, IEA said, including slow economic growth, declining populations, the expansion of diesel vehicle fleets, and the substitution of natural gas and renewables for heating oil and resid.

Decreasing 3.3%/year, oil product demand in the Pacific countries of the OECD will incur the most pronounced decline. IEA's projections show that demand in these countries will fall to average 6.6 million b/d in 2014 from 8 million b/d in 2008.

While demand for naphtha climbs marginally, demand for all other major refined products in OECD Pacific countries of Australia, Japan, New Zealand, and South Korea will decline over the forecast period.

Naphtha demand will grow strongly in South Korea but decline rapidly in Japan as other, more-competitive petrochemical producers emerge in the Middle East and China. Demand for fuel oil will decline across the region, displaced by natural gas and nuclear energy.

Other regions

IEA forecasts that oil product demand in the Middle East will grow 4.3%/year on average to reach 8.9 million b/d in 2014, up from 7 million b/d in 2008.

The drivers of this growth are sustained economic expansion based on oil and gas, petrochemicals, heavy industry, and construction, in addition to a young and growing population, and fuel prices that are among the world's lowest.

Demand for resid in the Middle East will soar to meet ever-growing power needs, given the lagging development of domestic natural gas resources, IEA said. Also, demand for naphtha and LPG will increase sharply to feed the region's petrochemical plants.

In Latin America, IEA projects that oil product demand will climb 2.1%/year to 6.7 million b/d vs. 5.9 million b/d last year. Growth will be mostly concentrated in transportation fuels.

Oil product demand in the former Soviet Union is also forecast to grow 2.1%/year over the forecast period, averaging 4.7 million b/d in 2014. Fuel oil demand will post the largest percentage gain, climbing 3.8% to 500,000 b/d to meet power generation needs in Russia and elsewhere, and also to free natural gas volumes to support Russian exports, IEA said.

Oil supply

IEA sees non-OPEC oil supply slipping by a net 400,000 b/d by 2014 from 2008. In its previous projection, the agency forecast 6-year growth of 1.5 million b/d for these producers.

Downward revisions are focused on the former Soviet Union and the Canadian oil sands. Otherwise, IEA expects sustained conventional oil supply growth through 2014 in Canada, the US Gulf of Mexico, Brazil, and the Caspian.

OPEC crude production capacity will be a modest 1.7 million b/d, reaching 35.8 million b/d in 2014. This compares to the agency's year-earlier projection of 3.2 million b/d in capacity growth over the period. This lower outlook is based on weaker demand, contract negotiation, reduced cash flow, geopolitical turmoil, and increased resource nationalism, IEA said.

Supply of NGL and condensate from OPEC will rise by 2.6 million b/d to 7.3 million b/d over the forecast period. ✦

Alaska natural gas line remains top priority for Palin successor

Nick Snow
Washington Editor

Alaska Gov. Sarah H. Palin listed her efforts to begin constructing a massive natural gas pipeline as one of her main accomplishments when she announced her resignation on July 3. Lt. Gov. Sean Parnell said it will be his top priority when he takes over the governor's office on July 26.

"I will continue the course set by the governor that has produced such forward progress these past 2 years," he said after Palin's unexpected announcement. "I will continue to support and promote responsible resource development and energy development of all kinds for Alaskans."

Reactions within the state's congressional delegation were mixed. "I am deeply disappointed that the governor has decided to abandon the state and her constituents before her term has concluded," US Sen. Lisa Murkowski (R-Alas.) said on July 3.

The state's other US senator, Democrat Mark Begich, said, "I'm as surprised as all Alaskans by Gov. Palin's decision to step down with nearly 2 years left in her term. There was speculation she would not seek reelection, but she gave no indication of a resignation when I met with her for 45 min in her Anchorage office 2 days ago." He said that he looks forward to working with Parnell as governor "and the rest of the administration on the gas line, growing our economy, creating jobs for Alaskans and many other pressing issues facing our state."

Gas production's carbon costs

Natural gas's position as a cleaner form of energy and possible bridge to renewable and alternative sources isn't insulating it from closer environmental scrutiny. Critics say carbon consequences of producing gas need to be examined more closely, especially in the Rocky Mountains. Federal analysts and regulators apparently agree.

"We have a lot of natural gas. It is cleaner-burning than coal, but it does have carbon emissions and impacts from its production, particularly on regions and communities near where it's produced," said Sharon Buccino, the Natural Resources Defense Council's Land and Wildlife Program director.

Possible groundwater contamination from hydraulic fracturing or other production processes is the biggest issue, she said during a June 24 forum on gas at the Center for Strategic and International Studies. But carbon resulting from gas exploration, development, and production shouldn't be overlooked, she said.

"We're reviewing the analysis of life-cycle impacts of gas production. It's an area that hasn't been examined closely and bears closer analysis," said a second panelist, Michael Schaal, oil and gas division director in the US Energy Information Administration's integrated analysis and forecasting group.

'Built on assumptions'

"This is an issue that's built on assumptions. We need to get our arms around real numbers," said the panel's third member, Frank A. Verrastro, director of CSIS's Energy and National Security Program.

The US Environmental Protection Agency has prepared a draft assessment, which is open for public comment, of some environmental impacts associated with oil and gas E&P activity in the Mountain West.

"Among other preliminary findings, the assessment suggests an overall increase in some impacts from natural gas exploration and production. These findings suggest the need for further study regarding the environmental impacts of unconventional [gas E&P]," an EPA spokesman told me.

Such research helps EPA and others understand more about both causes and potential means to address pollution-related impacts, the spokesman said. The draft study, "An Assessment of the Environmental Implications of Oil and Gas Production: A Regional Case Study," is online at www.epa.gov/sectors/pdf/oil-gas-report.pdf.

Producers' early steps

Some producers already are taking steps to determine carbon impacts from their operations, according to a member of the second panel at the CSIS forum. David A. Trice, president of America's Natural Gas Alliance, said that its member companies are each preparing sustainability reports.

Trice, who recently retired as Newfield Exploration Co.'s chief executive officer, said the Houston-based independent is trying to manage its carbon footprint already. "We know it's going to be required and our shareholders will demand it. But we've only started and won't have any answers for about a year," he said.

Buccino said that carbon emissions management is only part of the gas production improvements that are needed. "There are ways we can get it out of the ground which minimize the impacts," she said. ✦

Gov. Sarah H. Palin confers with Lt. Gov. Sean Parnell on July 3 soon after Palin's resignation announcement. Parnell said that he plans to keep construction of a massive natural gas pipeline from the North Slope a top priority after he takes over on July 26.

Republican Don Young, Alaska's lone US House member, said, "I'm as surprised as anyone by this announcement, but I support her decision and I wish her well."

In her speech, Palin said her administration's accomplishments spoke for themselves. "We aggressively and responsibly develop our resources because they were created to better our world, to help people, and we protect the environment and Alaskans (the resource owners) foremost with our policies," she stated.

'Massive bipartisan victory'

Palin said the Alaska Gasline Initiative Act (AGIA), which the legislature passed soon after she took office, was "a massive bipartisan victory" with a 58-1 vote, and that it is "succeeding as intended, protecting Alaskans as our clean natural gas will flow to energize us, and America, through a competitive, proprivate sector project."

During her administration, Palin said, Alaska established a petroleum integrity office to oversee safe development, worked to bring oil and gas activity back to Point Thomson for the first time in decades, and passed a new oil and gas tax, ACES (for Alaska's Clear and Equitable Share).

She said ACES "is working as intended and industry is publicly acknowledging its success," adding, "Our new oil and gas clear and equitable formula is so Alaskans will no longer be taken advantage of. ACES incentivizes new exploration and development and jobs that were previously not going to happen with a monopolized North Slope oil basin."

Palin said her administration's accomplishments also included ethics reforms, slowing down the growth of government, strong support for education, and breaking ground on a new prison. "We built a subcabinet on climate change and took heat from outside special interests for our biologically sound wildlife management for abundance," she said. She added that she was ready to take credit, but only for hiring the right people.

She also said she felt compelled to speak out on energy, national security, and other issues and to campaign for candidates who share her views, but not while trying to still be governor in a toxic political environment she said developed after Republican presidential nominee John McCain made her his running mate last year.

Parnell said Alaska has a good team of state government officials to keep it moving forward. "We've got an extremely talented team of commissioners, and I intend to keep them working hard for our state. I will work with the governor to coordinate with the cabinet and staff on a seamless, stable transition. And I will work closely with legislators, community leaders, and individual Alaskans to accomplish these ends," he said. ✦

ASSE: OSHA discusses refining NEP audits

Paula Dittrick
Senior Staff Writer

Some refineries and their contractors are receiving a high number of violations as a result of the National Emphasis Program (NEP), US Occupational Safety and Health Administration officials said June 29.

OSHA officials spoke to a meeting of the American Society of Safety Engineers (ASSE) in San Antonio. US Department of Labor Secretary Hilda Solis addressed ASSE in an opening session. Solis assured ASSE members that OSHA is committed to workplace safety.

"Make no mistake about it, the Department of Labor is back in the enforcement business," Solis said.

In a separate session later that day, Patrick Kapust, an OSHA safety and health specialist in general industry enforcement, discussed audit results from the refining NEP, launched in June 2007.

The NEP involves detailed inspections of refiners and contractors (OGJ, Sept. 8, 2008, p. 21).

OSHA implemented a refining NEP based upon a US Chemical Safety and Hazard Investigation Board recommendation following the deadly Mar. 23, 2005, explosion at BP America Inc.'s Texas City, Tex., refinery (OGJ, Sept. 8, 2008, p. 20).

Refining NEP inspections

Kapust said 165 inspections had been done as of June 26, resulting in 681 violations of which 91% were serious, willful, or repeat violations. The refining NEP yielded an average 11.5 violations/inspection compared with a national NEP average of 3-3.1 violations/inspection for all industries.

"The current average penalty per serious violation is $3,469," Kapust said of the refining NEP. Most of the violations involve process safety issues, he said although he could not immediately elaborate.

Previously, OSHA sent letters to refinery managers emphasizing the need to comply with all applicable OSHA standards, particularly the process safety management of highly hazardous chemicals (OGJ Online, June 24, 2009).

OSHA sent letters to more than 100 refineries, outlining compliance issues found under the refining NEP and urging refinery managers to comply with the process safety management standards. The standard requires employers to develop and incorporate comprehensive, site-specific safety management systems to reduce the risks of fatal or catastrophic incidents.

OSHA's acting director

Acting Assistant Secretary of Labor Jordan Barab told ASSE participants that OSHA's standards need to be updated because most standards were implemented in the 1960s and the early 1970s.

He noted current laws make it a lengthy, cumbersome process to update OSHA standards. "OSHA standards are the floor. They are the minimum," Barab said. "We certainly have no problem with people going beyond standards."

OSHA is working on vigorous enforcement efforts, and OSHA officials along with Congress are evaluating the current penalty structure for companies found in violation of OSHA standards, he said.

"We're looking at what we can do under the law to increase those penalties," he said.

Currently, the average nationwide penalty across all industries for an OSHA violation is about $900, he said. "This doesn't provide much of an incentive for a company not to cut corners."

Upon being asked when a permanent OSHA director might be named, Barab said it's unlikely that it would be done before September or October. He noted that no nominations have been made yet.

Meanwhile, he said OSHA is going "full speed ahead even though I'm acting director."

Barab joined OSHA as deputy assistant Labor secretary for occupational safety and health as well as acting assistant secretary on Apr. 13. He previously served as special assistant to the assistant Labor secretary for OSHA during 1998 to 2001. ✦

ASSE: Valero says VPP helped its contractors

Paula Dittrick
Senior Staff Writer

Valero Energy Corp. said the Voluntary Protection Programs (VPP) helped its contractors implement comprehensive safety and health management systems. VPP is a cooperative program offered by the US Occupational Safety and Health Administration.

Sean Gillilan, a senior health and safety specialist for Valero, told a meeting of the American Society of Safety Engineers (ASSE) that seven contractors at the company's 205,000-b/cd Bill Greehey Refinery in Corpus Christi, Tex., achieved injury and illness rates below the national average.

"The more companies that are working with successful safety and health programs, the safer the refinery will be," Gillilan said. "The companies that embrace the VPP concept of continuous improvement are no longer stagnant in safety but are now constantly improving every year."

Valero has 11 worksites in 5 states participating in VPP. Nationwide, VPP participation encompasses more than 2,200 worksites covering more than 800,000 workers. Numerous oil and gas companies participate.

Recently, the Government Accountability Office issued a report suggesting OSHA strengthen VPP's oversight activity and documentation to ensure consistency with existing OSHA polities.

"First, OSHA has not developed performance goals or measures to assess the performance of the program," the GAO report said. OSHA exempts VPP sites from routine inspections although these sites are subject to inspections following fatalities, serious injuries, and complaints from workers about safety and health hazards.

VPP sites are required to have injury and illness rates below the average rates for their industries as published by the Bureau of Labor Statistics. These rates must be below the average industry rates for 1 of the most recent 3 years.

OSHA is responsible for the initial approval of all VPP sites. Once approved, VPP participants commit to continuously improve workplace safety and employees health, maintaining low injury and illness rates. Participants report annually to OSHA.

ASSE represents more than 32,000 occupational safety, health, and environmental professionals worldwide. ✦

ASSE: OSHA launches Texas construction safety initiative

Paula Dittrick
Senior Staff Writer

US Department of Labor Secretary Hilda L. Solis plans a construction safety initiative in Texas to prevent workplace injuries and fatalities, she told a meeting of the American Society of Safety Engineers.

The Occupational Safety and Health Administration will implement the construction safety initiative. Solis said more workers die on construction jobs in Texas than in any other state. This involves all types of construction work, including oil and gas projects and expansions. Statistics show 67 fatalities in Texas construction last year and 33 so far this year, Solis said on June 29.

"Beginning in July, OSHA will increase the number of inspectors in Texas for a concentrated effort to prevent injuries and fatalities at construction sites," Solis said. "When these inspectors observe unsafe scaffolds, fall risks, trenches, or other hazards, they are empowered to launch an immediate investigation."

Solis told reporters after her speech that she is dissatisfied with OSHA's current reputation and that she wants "to see a turn to the respect that OSHA needs." She emphasized repeatedly that DOL is willing to work with businesses.

She submitted a budget request for fiscal 2010 that would enable OSHA to hire 130 new inspectors and 25 more discrimination investigators.

ASSE represents 32,000 occupational safety, health, and environmental professionals who work with employers to protect workers and employers' property from safety, health, and environmental risks.

In opening statements at the ASSE meeting, Solis and ASSE Pres. Warren Brown both mentioned concerns about crane safety. ASSE is working to help lawmakers and regulators develop updated crane safety standards. ✦

Nigerian militants threaten proposed Trans-Sahara gas line

Eric Watkins
Oil Diplomacy Editor

Nigeria's militant Movement for the Emancipation of the Niger Delta (MEND), reiterating its long-standing demands that international oil companies leave the oil-producing Niger Delta, has threatened to attack the planned Trans-Saharan gas pipeline project.

MEND "warns the investors to the Trans-Saharan Gas Pipeline (TSGP) project that unless the Niger Delta root issues have been addressed and resolved, any money put into the project will go down the drain," according to a MEND spokesman.

"We will ensure that it [the TSGP] faces the same fate other pipelines are facing today," the spokesman said. He also warned "Agip, Total, Shell, and ExxonMobil to leave while there is still time because within the next 72 hr" the group may launch new attacks.

The MEND warnings came just days after Algeria, Niger, and Nigeria signed an agreement to start the process of constructing the $10 billion TSGP, which aims to transport as much as 30 billion cu m/year of gas to Europe.

The warnings also follow a decision announced by Russia's OAO Gazprom of plans to invest in the TGSP through a 50-50 joint venture, called Nigaz, with state-owned Nigerian National Petroleum Corp.

Gazprom said Nigaz intends to explore for gas and to develop infrastructure for its development and transport—even including a section of pipeline that could form part of a proposed Trans-Sahara pipeline to export gas directly to Europe (OGJ Online, June 30, 2009).

While no date has yet been given for the start of work on the TSGP, which is expected to extend 4,000 km from Africa to Europe, the line's first shipment of gas is scheduled for delivery in 2015.

Threats played down

Nigerian military forces played down MEND's threats, saying that the group is not capable of carrying them out. According to military spokesman Col. Rob Abubakr, Nigerian security forces would be able to protect all oil and gas installations, as well as the sector's workers and staff.

But such reassurances may not be enough for international oil companies, especially since MEND-led sabotage operations—as well as kidnappings of oil company employees—has led to a significant drop in Nigeria's oil production, which has fallen to 1.8 million b/d this year from 2.6 million b/d in 2008.

Underlining their determination to

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Peace needed in Xinjiang

If you believe Chinese oil and gas officials, ethnic clashes in the province of Xinjiang—where 150 people are reported to have been killed—have not affected any operations at oil fields or pipelines.

Sinopec said its facilities are far from the riots, and the situation in the westernmost area of Xinjiang appeared to have stabilized last week. Sinopec owns Tahe field in Xinjiang, which is one of its largest fields in China.

PetroChina said its facilities were not affected either. It operates two large oil and gas fields in Xinjiang, one in the Tarim basin in southern Xinjiang and another in Kelamayi, northwest of Urumqi. PetroChina also owns the 6 million tonne/year Dushanzi refinery.

No one denies such statements as much of the rioting seems to have taken place in and around Urumqi, the provincial capital. Moreover, the riots may well not result in wider attacks on state energy infrastructure unless they become more organized.

Restless Xinjiang

Still, as one observer noted, the Chinese government cannot afford a restless Xinjiang because the resource-rich region makes a significant contribution to energy security, sitting atop 20% of China's oil reserves and about the same percentage of the country's annual coal output.

No less important, Xinjiang's long borders with oil-producing Central Asian countries make it strategically important to Beijing, a point underscored last week by an announcement that the extension of the oil pipeline from Xinjiang to central Kazakhstan and on to the Caspian Sea has passed initial tests.

The Kenkiyak-Kumkol pipeline will give China access to more of its Central Asian neighbor's oil resources in its western regions, which begin at the Kenkiyak field managed by the China National Petroleum Corp.

With an eye to shepherding even more oil and gas its way, China has been engaging its Central Asian neighbors through the Shanghai Cooperation Organization, giving Beijing an opportunity to influence the region's cash-poor but energy-rich member countries.

'Loan-for-oil'

Earlier this year, for example, China and Kazakhstan agreed to a $10 billion "loan-for-oil" deal that allows CNPC to buy stakes in the company Mangistau-Munaigas—a strategic purchase as the Kazakh firm owns the fields near the extended oil pipeline.

Underlining their determination to acquire even more oil from their Central Asian neighbor, Chinese oil companies also have been buying shares in a host of Kazakh oil producers, including PetroKazakhstan and CNPC-Aktobe-MunaiGas, operator of Kenkiyak and Zhanazhol fields.

"The implementation of this project will have tremendous influence on the whole oil and gas industry, providing new opportunities for oil exports," according to an official of KazStroyService, the Kazakh firm handling the pipeline extension.

But the success of China's project clearly depends on Xinjiang, according to Zhang Dajun, a Beijing-based political commentator.

"In the context of the world's third-largest economy's strategy to secure its energy supply, Xinjiang has become more economically crucial than ever before," said Zhang. ✦

drive away IOC's, MEND militants July 5 claimed responsibility for bombing Chevron Nigeria Ltd.-owned Okan manifold, which controls most of the company's offshore oil to its loading platform in Delta State.

"The strategic Okan manifold which controls about 80% of Chevron Nigeria Ltd. offshore crude oil to its BOP Crude Loading Platform was blown up at about [8:45 p.m. on July 5]," the militant group said in a statement.

A Chevron spokesman, who said an investigation had already begun, said the firm would make no comment on the rebel claims.

In addition to that bombing, the rebels also claimed to have seized the chemical tanker, Sichem Peace, in Delta State waters for ignoring a warning to industry tankers to stay away from the Niger Delta.

"Their arrest is meant to serve as a warning to others that there are root issues that have to be resolved with the Nigerian government before normalcy can resume," MEND said.

MEND also claimed it attacked a facility operated by Royal Dutch Shell PLC on July 4. "We lashed out at the Shell well head 20, located at Cawthorne Channel 1 today at about [3 a.m.], the facility connects to the Bonny loading terminal in Rivers State," the group said.

A spokesman with Shell in Nigeria said the firm is investigating reports of an incident on part of their operations, but had no immediate comment on the claims by the rebel group.

The MEND attacks are a clear rejection of recent efforts by the Nigerian government to secure peace in the Niger Delta. On June 25, President Umaru Yar'Adua offered amnesty to any rebel in the Niger Delta who lays down his arms, beginning on Aug. 6.

The amnesty offer followed bombings by MEND, which were confirmed by IOC's operating in the country.

On June 19, Eni SPA reported a loss of 33,000 b/d of crude production and 2 million cu m/day of gas due to an attack on its pipeline in the Bayelsa State.

On June 18, Shell confirmed that it had halted the 100,000 b/d Trans-Ramos pipeline in Bayelsa State, following an attack carried out by MEND on June 17.

According to analyst BMI, militant groups such as MEND want a greater share of oil revenues to filter down into the region, which remains impoverished despite its hydrocarbon wealth.

"With little indication that the Nigerian government is successfully engaging with disenfranchised communities over grievances, the longer-term risk outlook also remains bleak," BMI said, adding, "Endemic poverty remains the main social factor destabilizing the Niger Delta." ✦

IOCs mostly reject terms of Iraq's latest bid round

Eric Watkins
Oil Diplomacy Editor

International oil companies (IOCs) have largely rejected terms offered by Iraq in the country's first bidding process for more than 30 years, with one bid awarded for an oil field out of six offered and no awards given for two gas fields.

BP PLC and China's CNPC International Ltd. were the only bid winners, accepting a $2/bbl agreement to work in Rumaila oil field in southern Iraq, which has known reserves of 17.7 billion bbl.

"BP and its partner CNPC are very pleased to have participated in the transparent and efficient process today," said a BP spokesperson. "We are looking forward to the next step towards finalizing the service contract to increase production of the Rumaila field."

Better terms sought

Iraq offered bids for a total of eight oil and gas fields in the auction, hoping that IOCs would help the country boost output to 4 million b/d and bring in revenues needed for postwar reconstruction.

However, the bid round floundered as IOCs sought better terms than the service contracts offered by Baghdad, which were based on companies accepting a fixed fee per barrel of oil instead of an equity stake.

IOCs also raised doubts about having to partner with Iraqi state-owned firms along with a requirement to share management of the fields, despite being required to provide full financing of the fields' development.

The tender process initially attracted offers from 31 IOCs including BP PLC, CNPC, Royal Dutch Shell PLC, and ExxonMobil Corp. in addition to a host of other companies from China, India, South Korea, and Indonesia.

However, after a day of bidding there were, apart from the BP-CNPC bid, no other successful tenders for the remaining five oil fields due to the gap between what the IOCs wanted and what the government was willing to pay.

China's CNOOC and Sinopec wanted $25.40/bbl for oil from Maysan field in southern Iraq, while Baghdad offered just $2.30/bbl. ConocoPhillips wanted $26.70/bbl to work in Bai Hassan oil field, while the government offered just $4/bbl.

A consortium comprised of Sinopec, Eni Medio Orient SPA, Occidental Petroleum Corp., and Korea Gas Corp. withdrew from bidding for Zubair oil field after its request of $4.80/bbl was met with an Iraqi government response of $2/bbl.

'Near farce' bidding

According to one observer, the bidding descended into "near farce" when Iraq's Oil Minister Hussein al-Shahristani asked IOCs to resubmit their bids after the initial offers were rejected by Chinese, American, Italian, British, Dutch, and South Korean energy firms.

"The companies can submit a new offer until 6 p.m. (1500 GMT) and these offers will be reviewed by the cabinet, who will take the final decision," said al-Shahristani. But representatives of several IOCs said the minister's invitation was impractical due to the lack of time to prepare a new offer.

Al-Shahristani denied that the bidding had been a failure, saying, "Our numbers were not far from reality, and proof of that is that BP accepted our price for Rumaila."

The minister also insisted that Iraq would still meet its primary objective of increasing production to 4 million b/d from 2.4 million b/d in the next 5 years. "I am very satisfied because of Rumaila we will produce more than 4 million b/d," he said.

But Samuel Ciszuk, Middle East energy analyst with IHS Global Insight viewed the bidding as disastrous for the country, saying, "It puts Iraq back on square one." ✦

Aramco, Showa Shell agree to solar-cell joint venture

Eric Watkins
Oil Diplomacy Editor

Showa Shell Sekiyu KK's wholly owned subsidiary Showa Shell Solar KK and Saudi Aramco have agreed to explore "the possibility" of engaging in a small-scale electric power generation business using solar power.

"Following basic investigations based on this agreement, pilot plants will be built and operated to test and verify technologies particularly those on connecting to the existing local independent grid (micro grid)," Showa Shell said.

Under the initial plan, Aramco and Showa Shell will choose several sites in Saudi Arabia to construct electric power plants capable of generating 1,000-2,000 kw, with each facility supplying electricity to 200-400 buildings, such as homes and schools.

The output from the plants, which will total 10,000 kw at a cost of several billion yen, will find support from Tokyo Electric Power Co. in electric power generation and in the operation of power distribution equipment.

The project will use copper indium diselenide solar cells, which are currently produced at a Showa Shell factory in Japan's Miyazaki Prefecture. These cells are cheaper to make than conventional cells because they do not contain silicon.

"Based on the result of the tests and verifications, the project will proceed to a full-scale commercialization phase in Saudi Arabia," the Japanese firm said.

However, Showa Shell's ambitions go well beyond Saudi Arabia, according to Japan's Nikkei Weekly which recently reported that, "Showa Shell aims to tap demand for energy in emerging countries in the Middle East, Africa, and Asia by leveraging the Saudi Arabian state-run oil company's strong finances and regional presence."

In May, Showa Shell announced a 5-year business plan and said it aims to capture about 10% of the global solar cell market by 2014. Global demand for solar cells has been rising rapidly over the past few years, and Showa Shell expects demand to reach 13 Gw in 2013.

The firm targets an overall pretax profit of ¥100 billion in fiscal 2014, of which half is to come from solar cell operations. For its oil business, which is facing declining domestic demand, Showa Shell is also targeting ¥50 billion in ordinary profit in fiscal 2014.

However, at the time, Arai and Showa Shell Chairman Shigeya Kato said the company may consider a reduction in its group refining capacity of 515,000 b/d in 2010-14 as the Japanese government expects domestic oil demand to fall on an average of 3.5%/year over the next 5 years.

In contrast, according to a report by analyst Global Insight, the Japanese government predicts the country's usage of solar power "is likely to grow tenfold up to 2020, while other regional markets such as China, Bangladesh, and India are also planning significant increases in solar panel technologies."

Under its new business plan, Showa Shell said it will raise its solar cell production capacity to about 1 Gw/year from the current 80 Mw/year—an expansion that is expected to help generate about half of the company's pretax profit.

Showa Shell has one solar cell factory with a capacity of 20 Mw/year, and recently built a 60-Mw electric power plant in Kyushu. The firm has also announced plans to build a third factory at a cost of about ¥100 billion, with the site yet to be determined.

Showa Shell Solar is a 100% subsidiary of Showa Shell Sekiyu. Aramco has a 15% stake in Showa Shell Sekiyu, Japan's fifth largest refiner, which is 35% owned by Royal Dutch Shell PLC. ✦

Gazprom, Kogas sign MOU for Sakhalin-2 pipeline project

Eric Watkins
Oil Diplomacy Editor

Russia's OAO Gazprom and South Korea's Korea Gas Corp. (Kogas) have signed a memorandum of understanding to study the possibilities of supplying Russian natural gas to South Korea by extending the Sakhalin-Khabarovsk-Vladivostok (SKV) gas pipeline.

The agreement with Kogas comes in the wake of a recent visit to Japan by Russian leaders, including Prime Minister Vladimir Putin and Gazprom Chief Executive Alexei Miller, aimed at securing Japanese investment in the same pipeline development.

Gazprom started building the 1,830-km SKV pipeline in May and plans to complete its construction by yearend 2011. The line's initial capacity will be 7 billion cu m (bcm), according to Gazprom Deputy Chief Executive Alexander Ananenkov, who said it eventually will be increased to 47 bcm.

Kogas already receives 1.6 million tonnes/year of LNG from the Sakhalin-2 project following its launch in April, and under terms of an agreement signed by Kogas and Gazprom in September 2008, the South Korean firm will import 10 bcm/year of Russian gas during 2015-45.

However, Kogas is now said to be seeking to boost its imports of Russian gas by extending the SKV gas pipeline into South Korea—a distance of about 150 km.

According to analyst Global Insight, two pipeline options between Russia and South Korea are currently being evaluated: an overland route via North Korea and a direct subsea line.

"The first option suffers from severe geopolitical risks while the second option presents partners with formidable technological and financial challenges," GI said, adding, "A drawn-out negotiation and planning process for the project…can be assured in either scenario."

Underlining that point, Russian officials also have been courting Japanese investors into joining the SKV pipeline project.

Earlier this month, Russia's Putin visited Tokyo and invited Japanese companies to participate in the construction of the line as well as other facilities. ✦

Exploration may resume on blocks off Bahamas

BPC Ltd., Perth, and Norway's StatoilHydro ASA formed a joint venture to explore for oil and gas off the Bahamas if the government approves license applications.

The companies propose to explore licenses in southwestern Bahamas waters that lie between Miami and central Cuba. The Bahamas commonwealth government could approve the license applications by yearend, BPC said (OGJ, May 18, 2009, Newsletter).

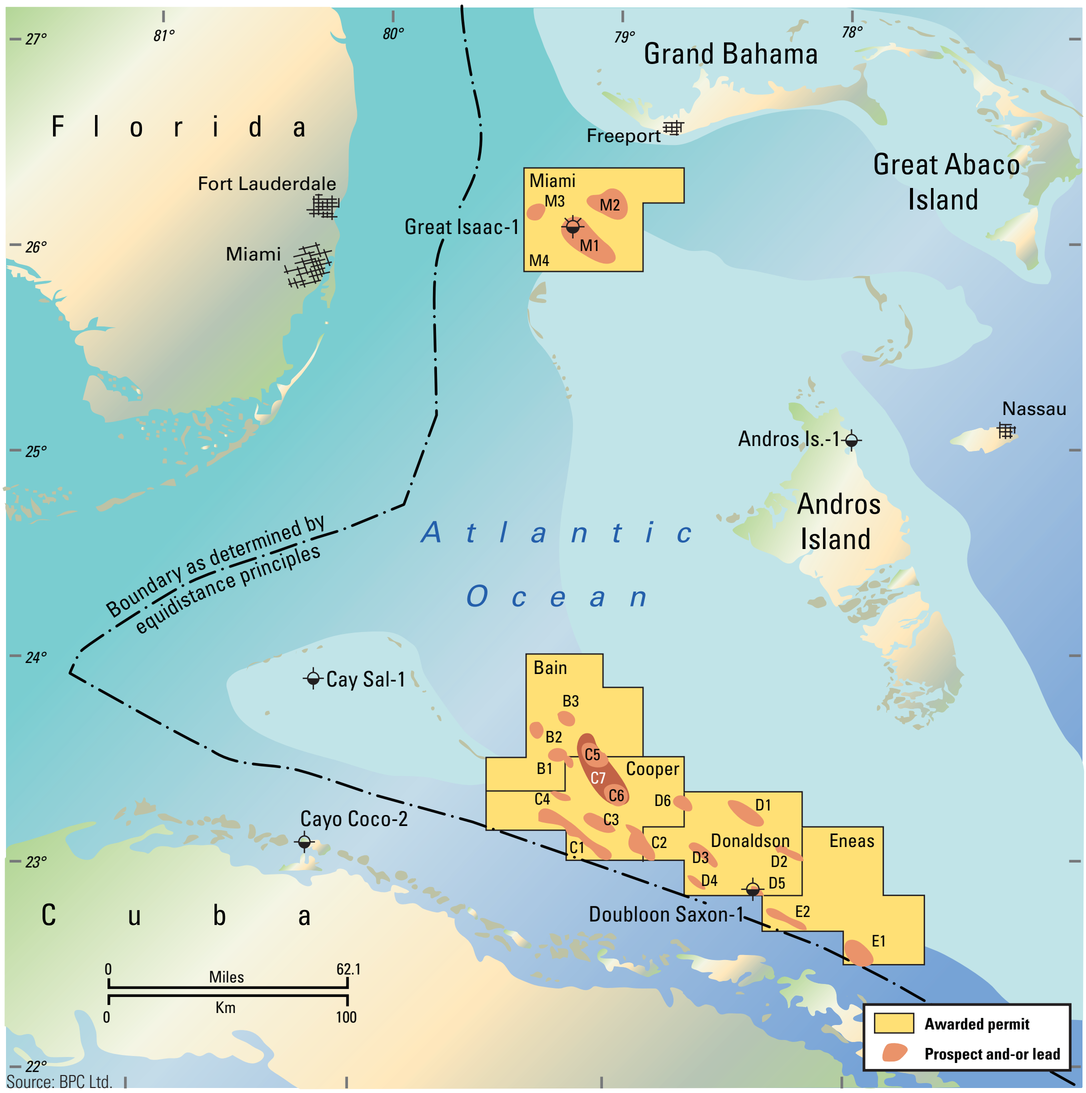
The joint venture territory lies between four other Bahamas blocks wholly held by BPC southwest of Andros Island and six blocks in the Florida Straits off northwestern Cuba operated by Repsol YPF SA in which StatoilHydro holds 30% interest.

Meanwhile, BPC has identified 22 exploration leads on its fully owned Bain, Cooper, Donaldson, and Eneas licenses 225-425 km southeast of Miami and the Miami license 85-150 km east of Miami (Fig. 1). The licenses, awarded in 2007, total 3.874 million acres in 5-535 m of water on the southern Great Bahama Bank and have potential in a Jurassic-Cretaceous carbonate petroleum system.

BPC noted that five wells have been drilled in the Bahamas since 1947, the last one by Tenneco Oil Co. to 21,740 ft about 50 km off Cuba in 1986 that had oil shows in Lower Cretaceous (Table 1).

BPC PROSPECTS, LEADS OFF BAHAMAS

Fig. 1



Source: BPC Ltd.

Exploration history

Exploration of the Bahamas region has occurred generally in 12-year cycles, BPC noted.

The area's first well, Andros Island-1 on Andros Island, went to a total depth of 14,583 ft in 1947 without encountering significant hydrocarbons.

Gulf Oil Corp. drilled the Gulf 826-Y well west of Key West, Fla. It is the only well to have successfully flowed oil. It flowed 18 bbl of 22-24° gravity

Bahamas land, offshore exploration wells Table 1

Well	Year of discovery	Operator	Total depth, m	Age at total depth
Andros Island-1	1947	Superior	4,446	Early Cretaceous
Cay Sal-1	1959	Bahamas California	5,763	Jurassic or Early Cretaceous
Long Island-1	1970	Bahamas Gulf	5,351	Jurassic or Early Cretaceous
Great Isaac-1	1971	Bahamas California	5,440	Jurassic
Doubloon Saxon-1	1986	Tenneco	6,626	Early Cretaceous

oil from an interval of anhydrite and carbonate lithologies below 10,000 ft.

The second well in the Bahamas, drilled by subsidiaries of Chevron and Gulf, was Cay Sal-1. It went to TD 18,906 ft in 1959 and encountered live oil shows from 12,682 ft to total depth but tested no commercial hydrocarbons.

Gulf, Chevron, and Mobil drilled Long Island-1 in 1970 to TD 17,577 ft and plugged after finding minor live hydrocarbon shows around 15,900 ft. Chevron moved the rig to drill Great Isaac-1 to TD 17,847 ft. It found minor live hydrocarbon shows at 16,900-17,700 ft.

"Drilling fluids were 9.2 ppg drilling into the overpressured reservoir and were eventually increased to 16 ppg before drilling on to TD. However, no commercial quantities of hydrocarbons were reported on tests," BPC said. ✦

Corridor sees 67 tcf in New Brunswick shale

Consulting engineers arrived at a best estimate of 67.3 tcf of gas in place in the overpressured Carboniferous Frederick Brook shale in the Sussex and Elgin subbasins in southern New Brunswick, said Corridor Resources Inc., Halifax.

The F-58 well in McCully field has been flowing at a stable rate of 150 Mcfd at 550 psi wellhead pressure into the McCully gathering system for 14 months and has recovered 69 MMcf of gas following a small 9-tonne frac in the albitic/dolomitic (lower) section of Frederick Brook, Corridor said.

The McCully P-76 well flowed gas at the rate of 150 Mcfd for 76 hr at 32 psi final wellhead pressure from Frederick Brook after a 14-tonne frac before the well was completed uphole in the McCully sands.

Depth to the top of the shale is 2,000-3,000 m in much of the area, but the shale is so thick that more than 1 km of exposure can be attained without horizontal drilling.

Free gas in place in the shale averages 370 bcf/sq mile and exceeds 600 bcf in places, and the estimate does not consider adsorbed gas within existing kerogen which may add greatly to the total volume of gas in place.

The consulting engineers' report will assist in fashioning a longer-term plan for appraising and development the shale, Corridor said. ✦

AWE to drill several New Zealand play types

Australian Worldwide Exploration Ltd., Sydney, is looking at drilling three or four exploration play types in its summer exploration in New Zealand's Taranaki basin.

In a website presentation originally given to the Petroleum Exploration Society of Australia, AWE says its first well, Hoki-1, will be a Cretaceous North Cape formation play in PEP 38401 about 100 km due west of New Plymouth.

The Hoki-1 structure covers 70 sq km with 100 m of relief. The structure, in 150-900 m of water, lies geologically under the edge of the Western Platform.

AWE operates PEP 38401 with 50% interest. The other Hoki partners are OMV 31.25% and Todd Energy 18.75%.

AWE plans two wells as extensions to the Tui oil field pool in the Kapuni Group F10 sands. They are Tui Northeast, with an estimated 10 million bbl recoverable, and Tui Southwest with 5 million bbl.

AWE also outlined two other possible targets adjoining the Tui pool: Tui Southeast with 10 million bbl estimated recoverable and a Kahu channel play with a 30 million bbl target.

A fourth proposed well is Tuatara-1, off the South Island's D'Urville Island. It is a Moki sands play similar to OMV's Maari oil field. The top Moki sands at Tuatara cover a 10 sq km structure with 90 m of relief. AWE holds 100% of PEP 38524.

A fourth play type being considered for this drill round is the Bahamas Pleistocene biogenic gas play more than 100 km west of Taranaki largely in PEP 38483. While distant from shore, it appears to have a large upside, the company said.

The Kan Tan-IV semisubmersible is to arrive in New Zealand in November. ✦

Guatemala

The PetroLatina subsidiary of Quetzal Energy Ltd., Toronto, is redeveloping the A7-2005 license that contains Atzam and Tortugas fields in Guatemala's southern Peten (Chapayal) basin.

It plans to drill three development wells at Atzam and six in Tortugas.

PetroLatina has spud the Atzam-3 well in Guatemala's Atzam oil and gas field in License A7-2005 in the southern Peten (Chapayal) basin.

Projected depth is 4,200 ft at the well, 500 m east of the productive Atzam-2 well. Quetzal chose the location to gain a structural advantage to Atzam-2 at the productive Coban C-18 and C-19 intervals.

Basic Petroleum (Bahamas) Ltd.

drilled Atzam-2 in 1993. The reworked Atzam-2 has produced 102,168 bbl of 34° gravity oil from March 2008 until May 31, 2009. Previous operators produced 90,000 bbl before the well watered out.

PetroLatina also completed Atzam-1A as a water disposal well for a savings of $18,000/month.

Indonesia

CBM Asia Development Corp., Vancouver, BC, said it has applied through its Indonesian partner PT Ephindo for a second coalbed methane production sharing contract in the Kutei basin of East Kalimantan, Indonesia.

The application covers 56,300 ha next to the company's Kutai West PSC. CBM Asia, which has an 18% working interest in Kutai West, will hold a 40% working interest in the new contract if a PSC is awarded.

CBM Asia is responsible for carrying out a $5.6 million exploration and appraisal program by November 2011 to determine commercial feasibility of CBM production on Kutai West and submit a development plan to the government.

Norway

TGS-NOPEC Geophysical Co. began shooting a multiclient 3D seismic survey in the Barents Sea off Norway.

The survey covers 4,300 sq km over the Hoop fault complex on the Norwegian continental shelf. It covers recently awarded acreage and open blocks expected to be offered later.

Thailand

Pan Orient Energy Corp., Calgary, said its NSE-I1 well in Thailand discovered commercial hydrocarbons in a previously untested volcanic reservoir 20 m thick at 637 m true vertical depth.

The well is pumping 75 b/d of 34° gravity oil and 200 b/d of water. Pan Orient is operator with 60% working interest.

NSE-I1 was deviated to target the shallow volcanic zone in the downthrown fault closure west of the NSE North fault compartment and a deeper volcanic objective on the high side of the north-south bounding fault.

The well encountered the first volcanic target zone at 637 m TVD and had moderate drilling fluid losses with oil shows observed at surface. It encountered the second volcanic objective at 750 m TVD with the upper 85 m penetrated before drilling was terminated while still in the zone. Minor oil shows were observed at surface along with minor mud losses while drilling through the zone. Subsequent testing of the lowermost objective recovered water and 2 bbl of 32° gravity oil.

The company plans to test the same zone structurally much higher on the east (high) side of the main bounded fault.

Turkey

Sherritt Oil & Gas Ltd. plans to spud the Durusu-1 wildcat on the western Black Sea shelf off Turkey in early July.

The 125 bcf gas prospect is to be drilled by a group led by Sherritt with 21%, HEMA Energy 33%, Toreador Resources Corp. 25%, and Soeul City Gas 21%.

Newfoundland

Vulcan Minerals Inc., St. John's, is moving in a rig to drill a deep well in the Bay St. George basin onshore western Newfoundland.

Vulcan Minerals plans to drill Robinson's-1 to 3,600 m in a joint venture with Investcan Energy Corp.

The site is on Permit 03-106 about 40 km southwest of Stephenville. The basin's deepest well to date is Hurricane-2 to 935 m in 2005.

Louisiana

Energy XXI USA Inc., Houston, identified several pay zones at the McIlhenny-1 well sidetrack 2 in Vermilion Parish, La., said interest owner Yuma Exploration & Production Co., Houston.

Lower Miocene Cris A sands at 21,500 ft measured depth stabilized at 15.8 MMcfd of gas at 14,873 psi on an 11⁄64-in. choke. Initially, the zone also produced oil at nonstabilized rates between 800 b/d and 2,000 b/d.

No other zones were tested, and the well is shut-in pending installation of production facilities and flow lines. TD is 23,300 ft MD, 23,329 ft TVD.

Yuma's working interests are 6.25% before payout and 23.44% after payout in the well, on Yuma's Cote de Mer prospect.

Nevada

Empire Petroleum Corp., Tulsa, is preparing to drill a second exploration well in western Nevada's Gabbs Valley.

The company applied for a federal drilling unit with the Bureau of Land Management in Reno. Approval is expected by early fall.

The next well is to be drilled to 6,000 ft or a depth sufficient to penetrate 500 ft into the Triassic formation, which the company believes is the source of the oil shows encountered in the first well ¾ mile away. Geochemical imaging validates the new location.

Empire Petroleum has a 57% working interest in the well and 85,145 acres of federal leases in the prospect area and is evaluating options to fund its share of the drilling cost.

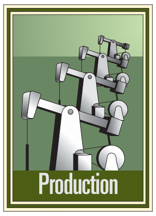
New Mexico

Completion work started on the Eumont State-2 well in Lea County, the first development well in Urssey Tank (Seven Rivers) field, said Saxon Oil Co. Ltd., Dallas.

It offsets the KPI Eumont State-1 discovery well, which has produced more than 60,000 bbl of oil since completion in May 2008. Eumont State-2 encountered the same subsurface zones of interest as Eumont State-1, said Saxon Oil, which has 15% working interest in the field.

Forecasts moderate Alberta oil sands production growth

Guntis Moritis
Production Editor



Various forecasters have lowered their expectation for increases in bitumen production from Alberta oil sands, but most still see a sizable rise during the next decade, with bitumen production of at least 2 million b/d in 2018 compared with 1.3 million b/d in 2008.

Alberta's Energy Resources Conservation Board in its recent update forecasts bitumen production to reach 2.7 million b/d in 2018.[1] This rate is a decrease from its forecast last year that saw oil sands production increasing to 3.23 million b/d in 2017.

For determining its current projections, ERCB has lowered its crude price assumptions and now expects US West Texas Intermediate to average $55/bbl in 2009 and increase to $120/bbl in 2018. The lower oil price expectations are one reason for the lower production forecasts.

The lower oil price scenario also ties into the slowdown in world economies that has lowered future oil demand and investment expectations.

Another recent forecast from the Canadian Association of Petroleum Producers estimates oil sands production under a growth scenario will reach 2.6 million b/d in 2018 and 3.3 million b/d in 2025. Without growth and with only projects currently in operations and under construction producing, CAPP expects production to remain relatively constant at 1.957 million b/d in 2018 and 1.987 million b/d in 2025.

In 2008, the Canadian Energy Research Institute forecast oil sands production potential of more than 5 million b/d by 2015 and 6 million b/d by 2030 and a reference case production of 3.4 million b/d in 2015 and 5 million b/d by 2030. CERI now has lowered its production outlook. In its February 2009 outlook, the institute now expects oil sands production to range from 1.9 to 2.9 million b/d in 2015 and from 3.7 to 5.4 million b/d in 2030.[3]

MINABLE AREAS UNDER ACTIVE DEVELOPMENT

Table 1

	Area, 1,000 acres	Initial established in place	Initial established reserves	Cumulative production	Remaining established reserves
		million bbl			
Albian Sands	34	4,227	2,636	308	2,334
Fort Hills	47	4,397	2,290	—	2,290
Horizon	70	5,246	3,378	—	3,378
Kearl	49	8,329	5,485	—	5,485
Jackpine	20	2,271	1,396	—	1,396
Suncor	47	6,228	4,322	1,573	2,749
Syncrude	109	13,028	8,215	2,334	5,882
Total	**375**	**43,725**	**27,722**	**4,215**	**23,514**

Source: Reference 1

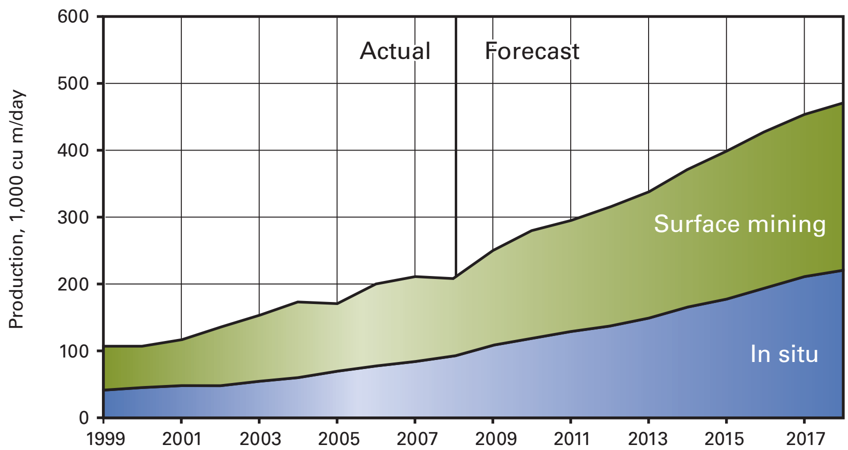
OIL SANDS REGIONS

Fig. 1

Source: Reference 2

OIL SANDS PRODUCTION FORECAST

Fig. 2



Source: Reference 1

Oil sands resources

The main deposits discussed in ERCB's report are the Athabasca Wabiskaw-McMurray, Cold Lake Clearwater, and Peace River Bluesky-Gething that cover about 54,000 sq miles (Fig. 1). Besides showing the three main oil sands areas in Alberta, Fig. 1 also indicates that Saskatchewan contains potential oil sands.

Fig. 2 shows the ERCB bitumen forecast to 2018 and Fig. 3 shows the disposition forecast for crude bitumen and bitumen upgraded into a synthetic crude oil.

The report contains the following assessment of bitumen resources in Alberta at yearend 2008:[1]

- Initial in place—1,731 billion bbl.
- Initial established—177 billion bbl.
- Cumulative production—6.4 billion bbl.
- Remaining established—170 billion bbl.
- 2008 production—0.477 billion bbl (1.30 million b/d).
- Ultimate potential—315 billion bbl.

The in situ volumes include production with enhanced recovery methods, such as injection of steam, water, or other solvents into the reservoir to mobilize the bitumen, as well as bitumen and heavy oil produced with primary methods from the Athabasca, Peace River, and Cold Lake regions.

ERCB currently is working on an update of the Upper and Lower Cold Lake Grand Rapids deposits and Athabasca Grosmont deposits. It expects to complete the assessment in 2009.

From its previous work, it reduced in the 2008 report the initial established reserves in Peace River to 5.5 billion bbl, based on a 20% recovery factor for thermal processes. But in the report, it also increased the area suitable for mining in the Athabasca region by 14½ townships, based on drilling in that area (Fig. 5). This change increased initial minable recoverable reserves to 38.7 billion bbl, up from 35.2 billion bbl in last year's report.

These two changes reduced the ERCB initial established reserves estimate by 1.9 billion bbl from that shown in the previous year's report.

Of the 170 billion bbl remaining established reserves, ERCB considers 80%, or 135 billion bbl recoverable with in situ methods and the remaining 34 billion bbl recoverable with surface mining methods.

The currently active mining developments contain 23.5 billion bbl and active in situ areas contain 3.5 billion bbl

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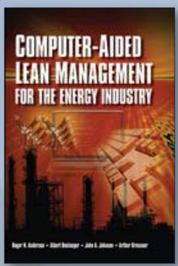

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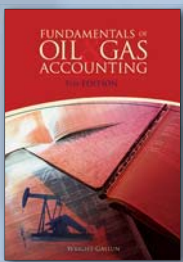

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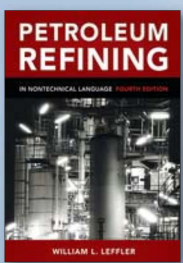

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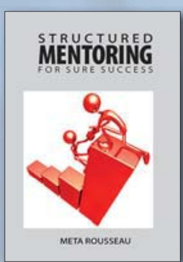

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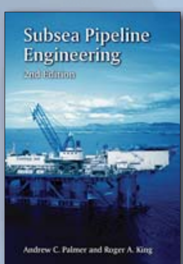

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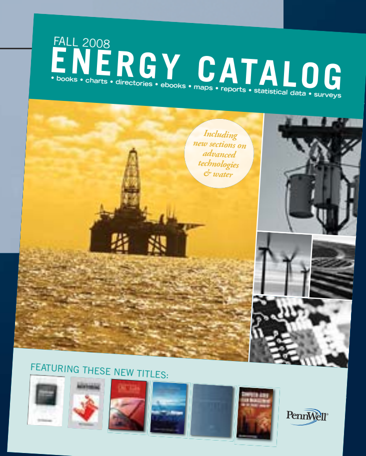

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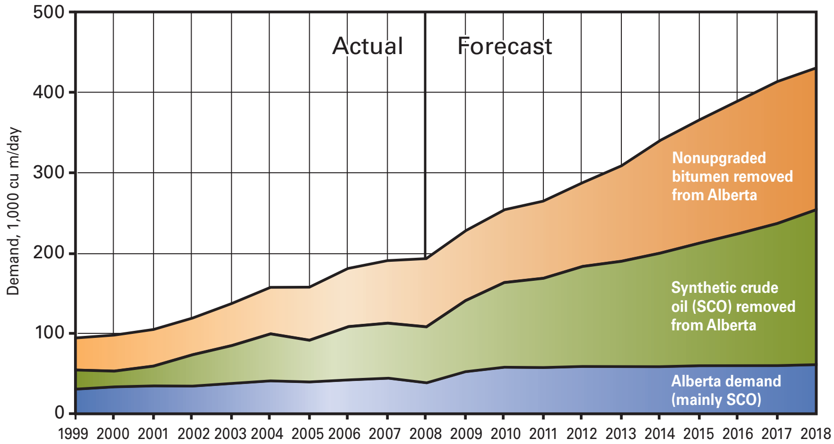
CRUDE BITUMEN, SCO DISPOSITION FORECAST

Fig. 3



Source: Reference 1

MINING PROJECTS CONSIDERED IN FORECAST

Table 2

	Start-up	Capacity, 1,000 b/d	Status
Suncor			
North Steepbank extension	2010		Under construction
Voyageur South Phase 1	TBD*	120	Application
Syncrude			
Stage 3 debottleneck	TBD	47	Announced
Stage 4 expansion	TBD	140	Announced
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD	115	Approved
Jackpine Phase 1A	2010	100	Under construction
Jackpine Phase 1B	TBD	100	Approved
Jackpine Phase 2	TBD	100	Application
Pierre River Phase 1	TBD	100	Application
Pierre River Phase 2	TBD	100	Application
CNRL			
Horizon Phase 2/3	TBD	135	Approved
Petro-Canada/UTS/Teck Cominco			
Fort Hills Phase 1	TBD	165	Approved
Fort Hills debottleneck	TBD	25	Approved
Imperial Oil/ExxonMobil			
Kearl Phase 1	TBD	100	Approved
Kearl Phase 2	TBD	100	Approved
Kearl Phase 3	TBD	100	Approved
Total E&P Canada			
Joslyn Phase 1 (North)	TBD	50	Application
Joslyn Phase 2 (North)	TBD	50	Application

*TBD—To be determined.
Source: ERCB

of remaining established reserves.

Besides the three mining projects that were on production, other projects that ERCB considers as active includes the Canadian Natural Resources Ltd. Horizon project that started producing synthetic crude oil in early 2009, the Petro-Canada Fort Hills development, the Shell Canada Ltd. Jackpine mine, and the Imperial Oil Ltd. Kearl project (Table 1).

ERCB estimates that the ultimate potential in situ bitumen recovery is 208 billion bbl from Cretaceous sediments and 38 billion bbl from Paleozoic carbonates.

In situ remaining established reserves in areas under active development are 90 million bbl in Peace River, 1,236 million bbl in Athabasca, and 2,350 million bbl in Cold Lake.

Production

In 2008, the upgrading of 264 million bbl of mined bitumen and about 8% of the 213 million bbl from in situ projects yielded 239 million bbl of synthetic crude oil. ERCB noted that bitumen production in 2008 increased by 9% from in situ projects while decreasing by 8% from mined projects, resulting in a 1% production drop from the oil sands compared with 2007.

In 2008, average production from the three oil sands areas was:

- Athabasca—721,500 b/d mined, 232,100 b/d in situ.
- Cold Lake—310,700 b/d in situ.
- Peace River—42,000 b/d in situ.

As noted previously, production from mining projects in 2008 decreased from 2007. In 2007, average production was 784,000 b/d from the three ongoing mining projects operated by Syncrude Canada Ltd, Suncor Energy Inc., and the Shell-operated Albian Sands project.

In 2008, Syncrude produced 47% of the mined production, while Suncor produced 34%, with the remaining 19% coming from the Albian Sands.

The ERCB report attributed the 8% production decrease to 338,000 b/d from Syncrude Crude Ltd. to two planned coker tunarounds and an operational upset during fourth-quarter 2008.

Suncor's production was 7% lower, at 247,000 b/d, due to planned maintenance, according to the report. ERCB expects Suncor's 2009 SCO capacity to increase to 350,000 b/d from the current 260,000 b/d.

Shell's Albian Sands produced an average 135,000 b/d in 2008, a 10% drop from the previous year. ERCB attributed the decline to execution of a mine tailing plan that temporary led to the production on lower grade ore and to planed and unplanned maintenance.

CNRL's Horizon project began

mining in September and produced 346,000 bbl in 2008. SCO from the production started in February 2009.

Table 2 shows the projects ERCB includes in its production forecast for minable projects. It excluded from the list the proposed UTS Energy Corp. Equinox and Frontier projects that, if implemented, would start up in the later part of its forecast.

ERCB forecast that production from mined project would increase to 1.56 million b/d in 2018 from the 0.72 million b/d in 2008.

Fig. 4 shows the historic in situ production from each of the three areas. ERCB expects production from in situ projects to increase to 1.39 million b/d in 2018 compared with 0.58 million b/d in 2008. Its 2018 production projection is 5% less than in its previous year's report.

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 2008, the oil sands have had 38,913 wells drilled for exploration and development of the resource. In 2008, companies drilled 4,627 wells in the oil sands. Of these, 1,209 were development wells and 3,428 were exploratory wells. According to the ERCB report, about 9,700 wells were on production during 2008, with the average well producing 62 bo/d.

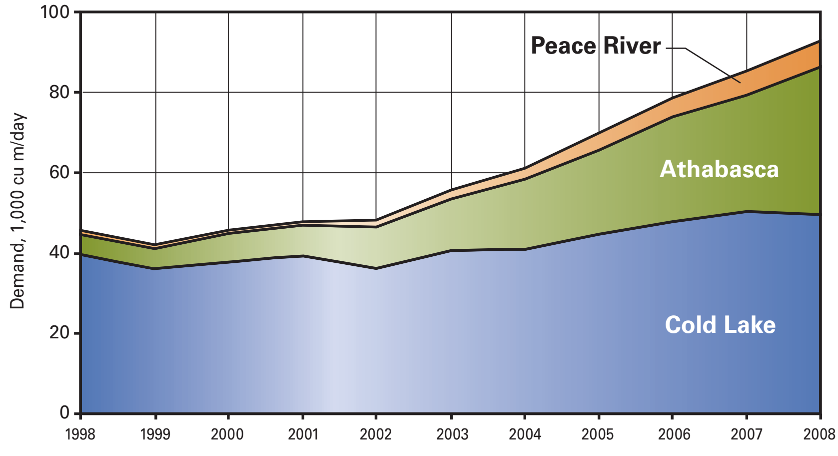
Production from the Cold Lake region accounts for 53% of the in situ production, with another 40 % produced in the Athabasca region and 7% in the Peace River region, the report says.

As with the mining projects, the timetable for additional in situ projects is uncertain.

CERI in its February 2009 forecast dramatically decreased its estimates of future capital investment in the oil sands (Fig. 6). In its economic slowdown projection, it expects companies to invest $218 billion (Can.) in new oil sands. This is $97 billion (Can.) less than its 2008 base case and $241 bil-

IN SITU PRODUCTION

Fig. 4



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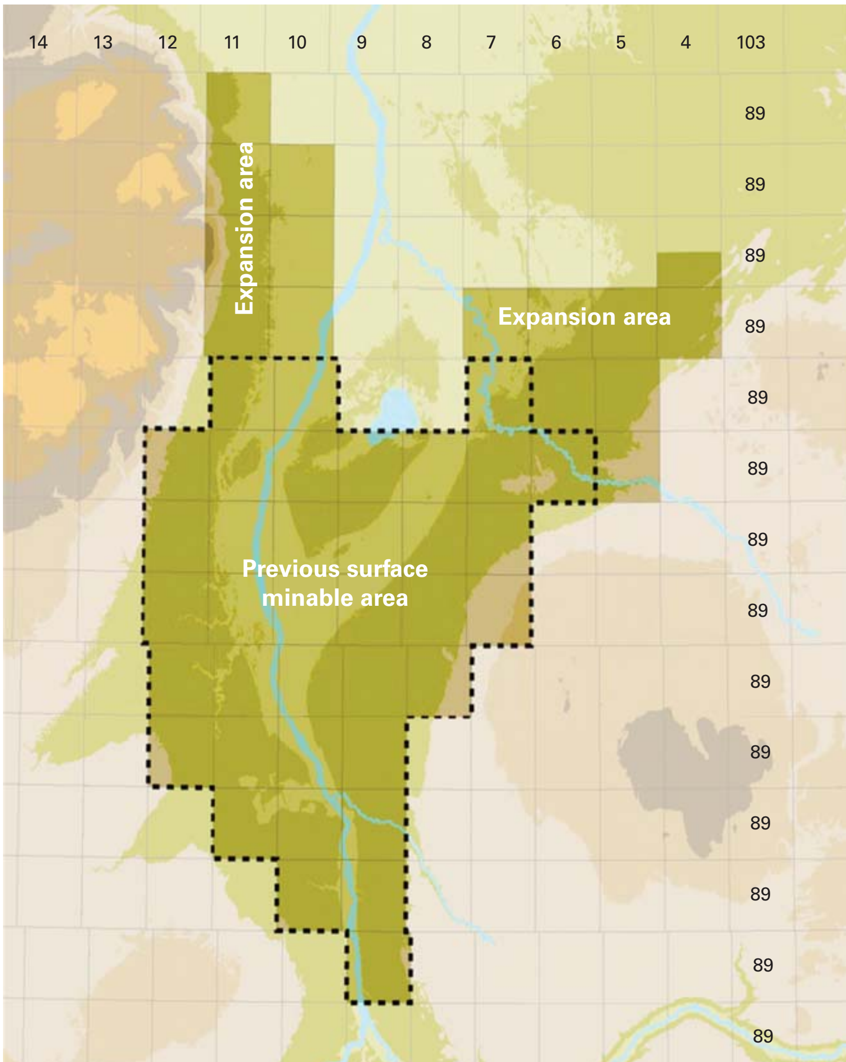
EXPANDED MINING AREA

Fig. 5



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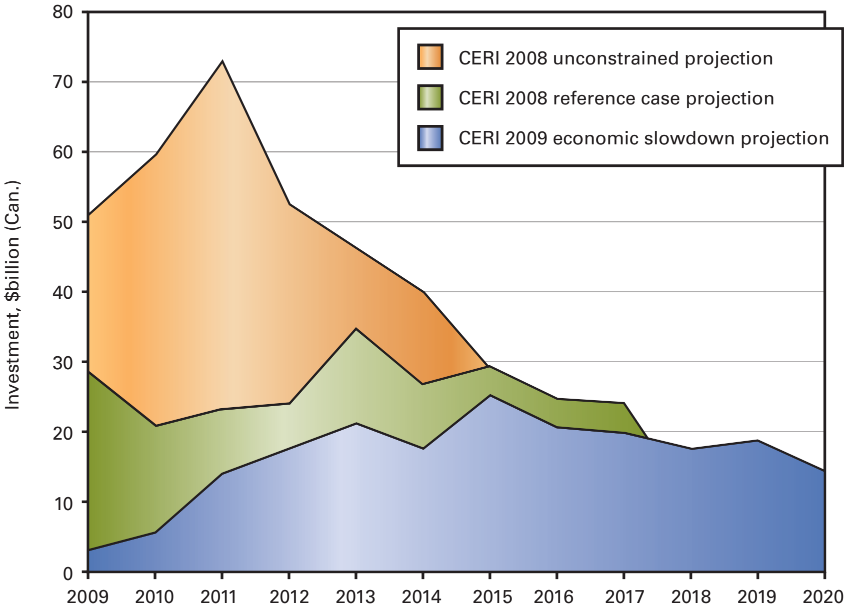
OIL SANDS CAPITAL INVESTMENT

Fig. 6



Source: Reference 3

lion (Can.) less than its 2008 unconstrained projection. ✦

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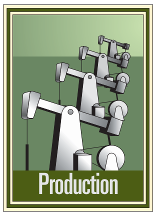
Cost reductions may rekindle some oil sands investment

John Dunn
Wood Mackenzie Ltd.
Houston



Cost deflation alone will not provide the necessary catalyst for companies to begin to sanction more oil sands projects. Based on a Wood Mackenzie analysis, we expect companies to stay in a low-cost safe mode until clear signs of an improvement in energy markets or the economic environment emerge.

Hit hard by industry cost inflation, Canada's oil sands projects now have some of the highest break-even prices of upstream assets globally. As a result, many operators have opted to delay, defer, or redefine their oil sands portfolios in order to effectively manage and control project costs, time scales, and potential returns through the economic downturn.

The question on everyone's lips now is when, and to what extent, will cost deflation filter through the sector.

With steel and labor accounting for more than 50% of a typical oil sands project's total cost, it seems inevitable that the collapse in the value of steel and a depressed labor demand will result in lower development costs.

In contrast to an inflationary environment, however, the cost of raw materials and wages can be slow in coming down as companies renegotiate contracts and redesign project scopes,

There are initial signs that project costs now are lower, but it is too early to tell if these reductions will be across the board.

Project status

An array of large and small companies has suspended or reduced activity levels on their oil sands projects amid the toxic combination of low commodity prices and high costs. As a result, these companies have avoided constructing multibillion-dollar projects at the height of global cost inflation, instead conducting the long and painstaking process of renegotiating existing contracts and redefining project scopes.

The list of projects that companies have scaled-back, delayed, or redefined includes both future phases of some of the region's established projects and new greenfield developments.

In addition to deferring decisions on development sanction, such as Petro-Canada at its McKay River and Fort Hills projects or Total E&P Canada Ltd. at its Joslyn development, some companies have withdrawn applications or postponed plans for upgraders in Alberta, including StatoilHydro at Kai Kos Dehseh and Total at Northern Lights.

Other operators have chosen to redefine project scopes and to place projects into a safe mode, such as Suncor Energy Inc. at its Voyageur project and Shell Canada Ltd. with the second expansion of its Alberta oil sands project (AOSP).

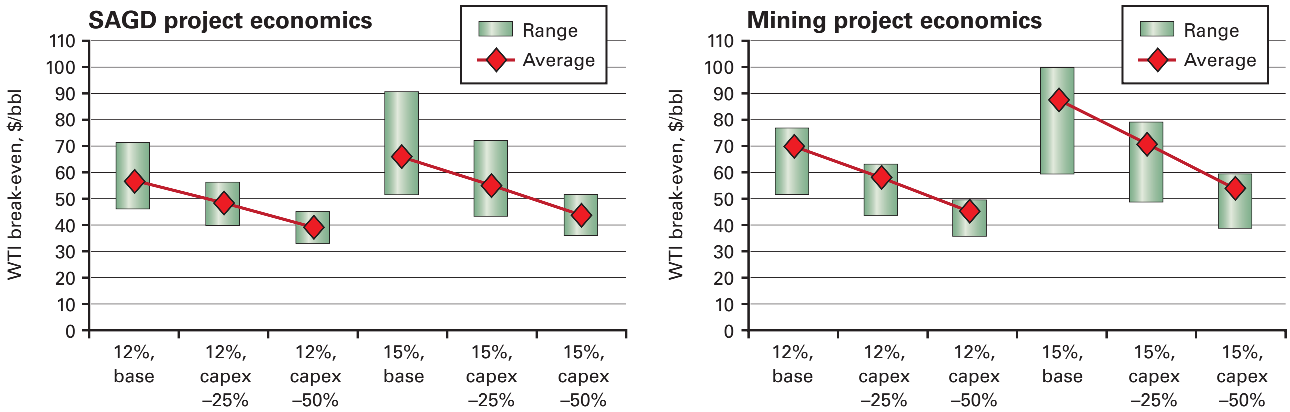
The slowdown also has affected the region's smaller operators, such as Connacher Oil and Gas Ltd. The company had deferred its second phase at Great Divide, named Algar, and temporarily constrained bitumen production in late 2008. The company, however, has reinstated production levels in light of narrowing bitumen differentials and restarted Algar construction.

Needless to say, new projects in undeveloped areas are unlikely in the short term, especially those championed by smaller companies, as they grapple with tight credit and debt markets.

One exception is the proposed 300,000-b/d Imperial Oil Ltd.-operated Kearl mining project. Although not materially redefining the project's scope or timing, the operator has taken time to work with its suppliers to drive down costs and also has delayed order-

PROJECT BREAK-EVEN POINTS

Fig. 1



Note: Break-even points at a 12% and 15% discount rate with a 25% and 50% capex reduction.
Source: Wood Mackenzie GEM

ing some of the project's long lead items in an inflationary environment. As a result, it made a go-ahead investment decision on the first phase in May.

Cost components

With steel price down 60% from its highs in 2008 and labor markets easing as industry activity rapidly slows in Canada not only in the oils sands but also in the conventional oil and gas sector, there is no doubt that a deflationary impact will filter through to the oil sands—although to what extent remains uncertain.

To date, there have been no widespread announcements of decreased costs, although early signals are emerging.

Husky Energy Inc. has indicated that costs to develop the first phase of its Sunrise project may have come down to $2.5 billion (Can.) or $2.1 billion (US) from $4.5 billion (Can.) or $3.8 billion (US). It cited the lower costs of steel, labor, and materials compared with the costs just 1 year ago.

In addition, Petro-Canada estimates that the cost of its Fort Hills mine could come down by 30% from previous estimates, putting the project cost at about $10 billion (Can.) or $8.3 billion (US).

The table below shows the scale and timing of cost reductions across different categories of expenditures.

Large integrated projects and standalone mining developments are likely the most sensitive and correlate the best with cost reductions of raw materials, such as steel, due to their massive scale and capital-intensive nature. On the other hand, stand-alone steam-assisted gravity drainage projects tend to be modular and more controllable and therefore are less affected by a lower cost of materials. This is borne out by the typical project economics displayed by integrated and nonintegrated SAGD projects, with the latter displaying lower break-even points and higher rates of return.

Labor is a vital element in the successful execution of an oil sands project. Labor constraints, poor productivity, and reliability issues have been at the heart of many project delays and cost increases announced during the last few years.

With oil sands operators lowering their activity level during the current economic turbulence, labor demand has decreased. An added benefit of the slowdown could be increased productivity because experienced skilled personnel continue to work with operators ensuring that they retain key staff members through the downturn, so that activity can ramp-up quickly.

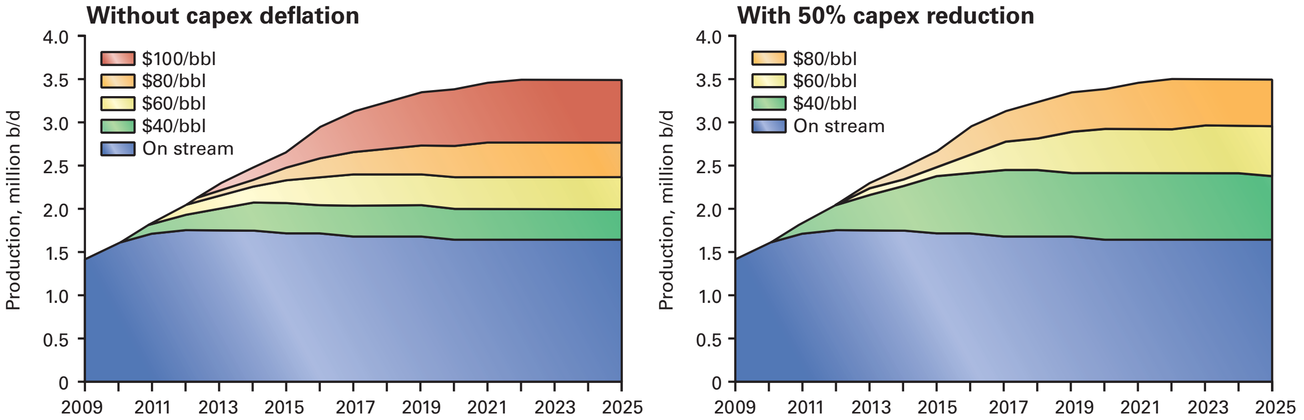
Furthermore, on any recovery, the development pace will be likely below the levels previously witnessed, and proportionally the percentage of short-term contract workers will decrease. In addition, vital personnel are unlikely to

COST REDUCTIONS

	Cost reduction, %	Factors	Timing and scale
Land rig rates	15-25	Returns on marginal drilling have fallen sharply	Already down 25-30%—sharp decline
Steel	15-30	Global prices have collapsed	Spot price down 60%—sharp decline
Oil services	10-20	+ Initial resistance to reductions – Reduction in activity	Starting to slowly fall—slow decline
Labor costs	20-30	+ Industry has recruited strongly to offset shortages – Contractor rates are high	6 months to 1 year from first negotiation—not expected to fall materially other than contractor rates

UNRISKED PRODUCTION PROFILE

Fig. 2



Note: Production profile under various WTI $US price thresholds with a 15% discount rate.
Source: Wood Mackenzie

leave projects before first production, in order to secure a more lucrative contract at another project. This will avoid some reliability and start-up issues that have plagued projects.

Project economics

To assess the effect of regional cost deflation on oil sands' project economics, our analysis considers the break-even points of future mining and SAGD projects. The projects included are future green field projects and future phases of existing projects except for three integrated legacy projects because of their economies of scale, long-term production experience, and infrastructure positions. These three projects are unrepresentative of the newer projects.

It also is worth noting that new integrated projects, without any existing production, generally display higher break-even economics than their nonintegrated counterparts. In light of recent project deferrals, however, there are no integrated projects in our data set that have an existing phase already in production.

We have analyzed the projects under two discount rates: 12% and 15%. It could be argued that such a long-lived and known resource be assessed with a discount rate of 10%, or below, especially when compared with, for example, a high-risk ultradeepwater development and its rapid production rate decline. We, however, see 15% as a more sensible planning assumption in the current environment, due to tight credit and debt markets.

In actuality, participants display varying appetites for risk as a result of different costs of capital and internal strategies. The drivers for selecting an appropriate discount rate are also the subject of much debate.

Without factoring in any regional cost deflation, we estimate that the average mining project break-even point is about $90/bbl and $70/bbl (West Texas Intermediate) at 15% and 12%, respectively (Fig. 1). The average SAGD project requires a $65/bbl and $55/bbl at the same discount rates.

A discount rate of 15%, in conjunction with a 25% and 50% decrease in total project capital expenditure results accordingly in average break-even points of about $55/bbl and $45/bbl for SAGD projects and about $70/bbl and $55/bbl for mining projects.

In essence, under our average SAGD results, a project is economic at less than $50/bbl WTI at a discount rate of 15%, with a 50% decrease in capital costs. Under the same metrics, a mining project would require more than a 50% decrease in costs to be economically viable at less than $50/bbl.

Another way to interpret our results is that to reduce the average break-even of our projects to $55/bbl or less, would require a cost reduction of 25% for a SAGD project but 50% for a mining project.

Long-term narrow bitumen differentials could offer much upside to our average break-even estimates for nonintegrated projects.

Our current long-term assumption is that bitumen trades at a 50% discount to WTI, which is about the historical average. Bitumen differentials, however, currently are narrow and hence some standalone projects could produce more favorable economics under a narrower assumption.

On the contrary, wide bitumen differentials favor integrated developments—a high quality product is generated from a low quality input—so that the inverse relationship holds true. Therefore, taking a short-term view on bitumen differentials for a long-life resource when making investment decisions introduces an added element of risk because bitumen differentials depend on the volume of nonupgraded bitumen sold to the market in the forthcoming years and its ability to displace extra heavy oil from Mexico and Venezuela delivered to the Gulf Coast region, which remains largely uncertain.

Future scenarios

To evaluate the potential impact of the prevailing oil price and industry cost deflation on the region's bitumen production forecast, we have considered our base unrisked profile and assumed that production does not go ahead if project or future phase break-evens equal or fall below several defined WTI price thresholds. We evaluated our production with and without a total capex reduction of 50%, at our preferred discount rate of 15%. It is assumed that all production currently on stream ramps up as per company plans (Fig. 2).

At a prevailing $60/bbl or less WTI price, under our base-cost assumptions, about 1 million b/d of future production could be at threat in 2020. If, however, there is a 50% reduction in total capex, under threat in the same year is less than 500,000 b/d of bitumen production.

Additionally, under our reduced cost scenario, companies would not constrain any production that we currently model if its break-even WTI price is $80/bbl or more. In reality, companies will delay production that is uneconomic under the prevailing cost and commodity price until costs decrease or oil prices increase.

Resource

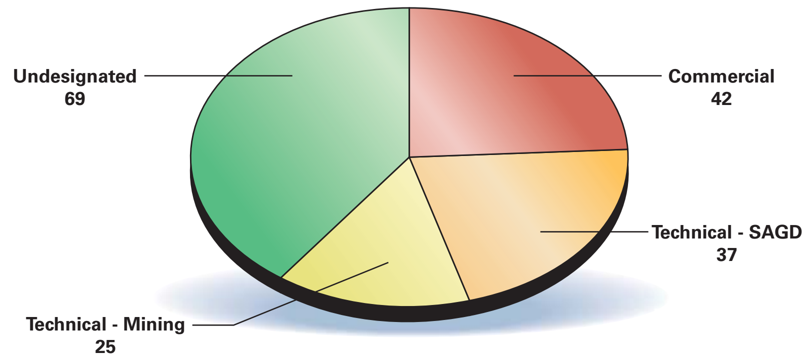
We currently model 24 commercial oil sands projects. These are projects that are onstream, have received development approval, or are likely to be developed in the near term. This represents around 42 billion bbl of recoverable bitumen reserves in total, of which 13% has been produced.

Until early 2009, our commercial reserves estimate was higher than this. As a result of recent project deferrals and delays, however, we have moved 6.8 billion bbl of commercial reserves across seven projects to a technical status because we believe that these projects are unlikely to proceed in the current environment.

Our identified technical and commercial reserves combined total about 105 billion bbl, only a proportion of the known 174 billion bbl of bitumen resource. We therefore still have about 70 billion bbl of undesignated resource not assigned to a project (Fig. 3).

OIL SANDS DEVELOPMENT STATUS

Fig. 3



Note: Technical reserves have not received approval or are unlikely to be developed in the near-term. Undesignated reserves have yet to be assigned to a project.
Source: Wood Mackenzie

There is no doubt that the long-term production potential of the oil sands region is immense and that the area remains one of the last global opportunities to acquire and develop a known long-life resource. Nonetheless, the rate at which companies will develop the resource depends on a range of factors, not least of which being the prevailing economic and commodity prices, environmental legislation, and regulatory factors.

Expectations

As would be expected, cost deflation materially improves oil sands' project economics, but integrated and mining projects, which are larger in scale and more capital intensive, require greater cost reductions for them to become viable at current prices. Moreover, cost deflation alone will not provide the necessary catalyst for project sanctioning decisions, and we expect companies to stay in a low-cost safe mode until clear signs of an improvement in energy markets or the economic environment emerge.

With the potential expansions of existing projects and the host of new projects previously noted, companies must ensure that upon any turnaround the overheated materials and labor market that has dominated the sector in recent years does not return. Companies can only achieve this by effectively planning and staggering future projects to manage efficiently the pressures placed on the region's infrastructure, service sector, and suppliers alike.

In turn, this would satisfy environmental groups, which have put pressure on the government to slow the pace of developing oil sands. ✦

The author

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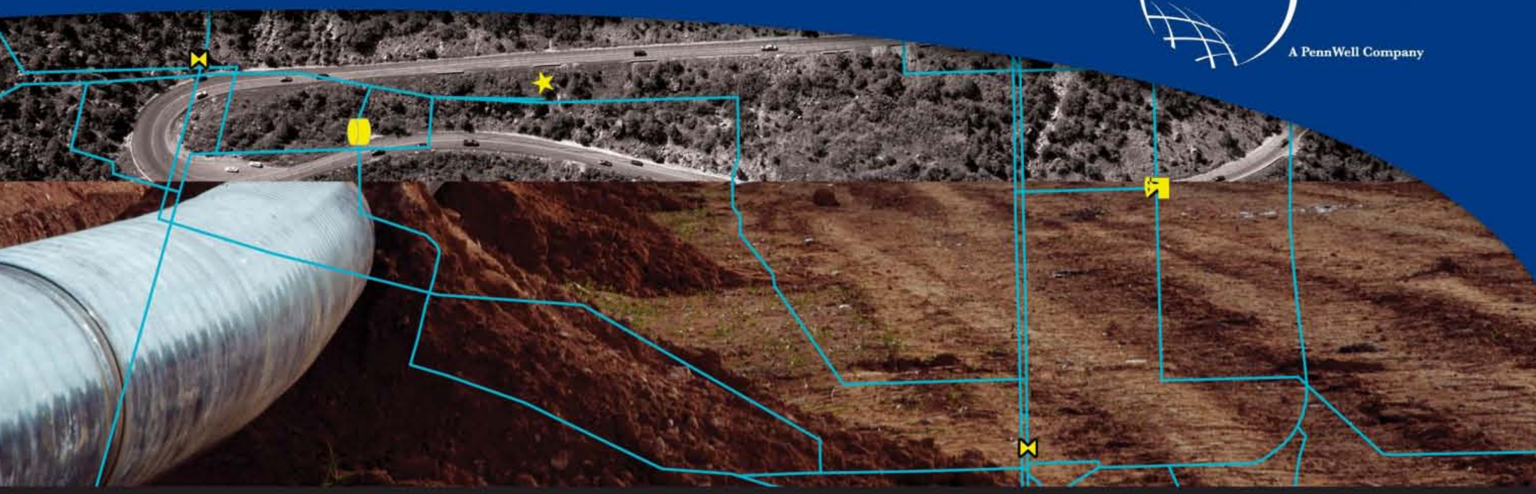

LOW CO_2 SLIP—1

Canadian experience shows actual operations needed to guide choice of amine simulator

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Experience in 2008 with various marketed process simulators modeling Suncor's Simonette gas plant showed that predicted results differed widely from actual operating conditions.

Choosing an amine simulator must accordingly be done carefully and the results adjusted on the basis of known operating data; otherwise the simulated values may prove questionable. In the design of a new amine system, reliance on numbers generated from a process simulator is not recommended no matter what previous successful results were obtained because even slight variations of the operating conditions and feed concentrations may cause widely varying results.

Therefore, an expert knowledge of amine systems with experience on similar, successful, and working installations provides the best reference for whether a system will behave as intended. Also, establishing a close working relationship with an amine supplier that will guarantee performance results of the amine in any contemplated gas-sweetening installation may help to circumvent problems such as the low CO_2 slip experienced at the Simonette plant.

Based on a presentation to the 88th Annual GPA Convention, Mar. 8-11, 2009, San Antonio.

That plant, while designed for a CO_2 slip application using methyldiethanolamine (MDEA) and operating at about 1,000 psig, was experiencing low levels of CO_2 slip. The plant's inlet acid-gas concentrations were 2-3% H_2S and CO_2 in varying proportions. The downstream stripped acid gas from the regenerator, subsequently flowing to a Claus sulfur unit, created operating problems due to the low-btu content of the acid-gas stream.

After a comprehensive review of available literature,[1-11] process modeling work was undertaken to study various parameter changes potentially affecting CO_2 slip, using actual plant mechanical data on actual tower diameters, tray spacing, active areas, weir heights, and tray types. Output from several process simulators, including equilibrium stage and mass transfer rate-based models, was compared with actual plant equipment and conditions in order to study the effects of varying column mechanical dimensions, amine circulation rate, inlet gas and lean-amine feed temperatures, and blends of amines.

The modeled results from all the simulators used did not compare favorably with the actual CO_2 plant slip, measured to be about 0.2%. While searching for a solution to optimize CO_2 slip by varying key parameters, the investigation turned to focusing on diethanolamine (DEA) contamination. It was coincidentally found that other Alberta high-pressure sweetening plants exhibited decreased CO_2 slippage as a result of blended amines, primarily with the introduction of small amounts of DEA. To date, there has been no comprehensive explanation of why Simonette and other installations suffer from low CO_2 slip.

DEA contamina-

EXISTING EQUIPMENT

Table 1

Equipment	MMbtu/hr
E-2-4 A/B lean/rich exchanger	12.5
E-2-6 A/B/C aerial cooler	14.2
E-2-7 reboiler duty	27.0
E-2-8 condenser duty	10.2

DISTILLATION COLUMN

Table 2

	C-520	C-2-1	C-2-2
Description	HP amine contactor	LP amine contactor	Regenerator
Size	78 in. ID X 60 ft T/T	54 in. ID X 64 ft T/T	66 in. ID X 57.5 ft T/T
Trays, no.	20	27	17
Tray type	1 pass Koch AC 5U	1 pass Glitch Type V-1	1 pass Koch Type V-1
Tray spacing, ft	2	2	2
Weir height, in.	3.125	3.5	2
Weir side width, in.	23.5 (to overflow); 29.5 (from downcomer)	25.5	26.25 (symmetrical about center line)
Active area, %	~77.9	~60	~84
Downcomer space, in.	15.5 (top) x 10.5 (bottom)	13.75 (straight, no sweep back)	8.75 (straight, no sweep back)
Downcomer clearance, in.	3.125	2.5	2
Fractional hole area, %	10.03	10	10

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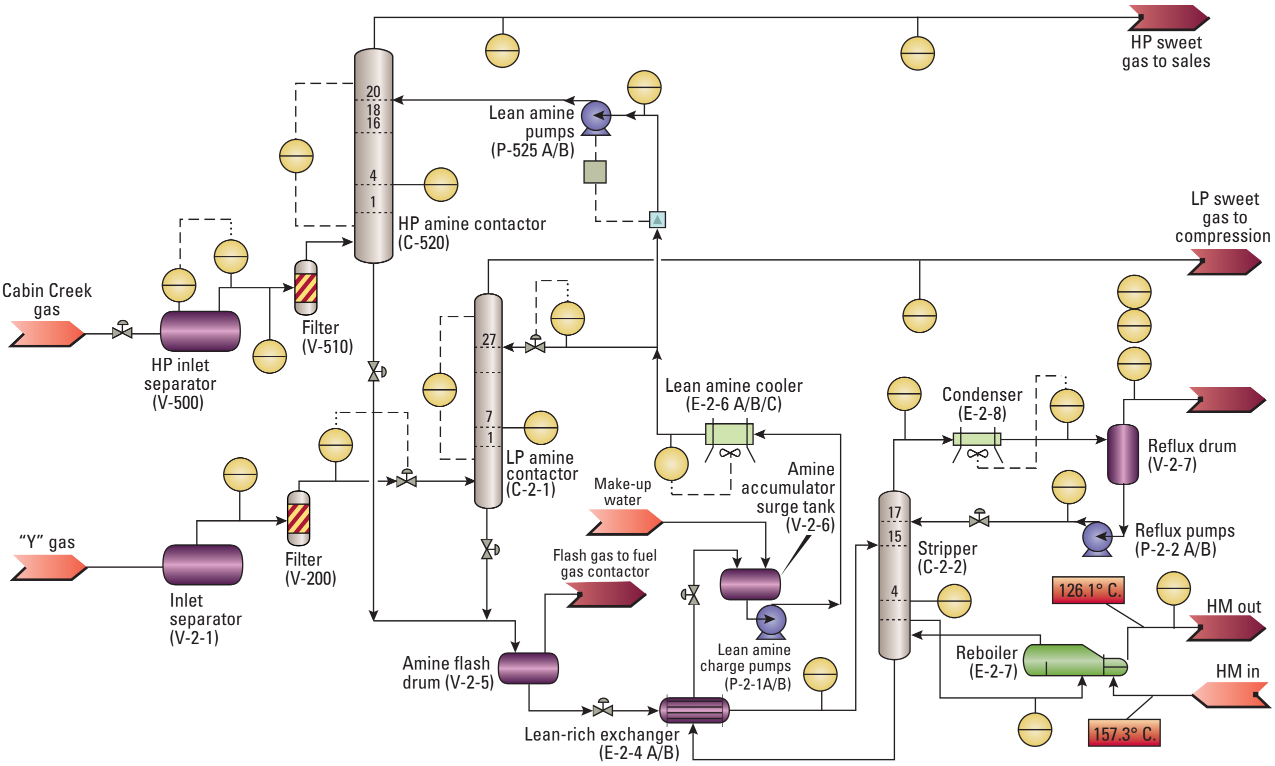
SUNCOR'S SIMONETTE GAS PLANT

Fig. 1



tion may be hard to avoid in the operating life of the high-pressure MDEA absorber system and, once present, may not be completely and adequately expunged to allow required CO_2 slip rates. An additive to negate the effects may be the only viable recourse. Further research may provide the definitive answers in the future.

This two-part series presents this experience together with the modeling results. It also presents a theoretical model of probable mechanisms for limited CO_2 slip that may help explain the effects of mixed amines at high pressure for CO_2 slip and MDEA applications.

The concluding article will focus on the actual simulation output comparisons and selected parameter sensitivities. In addition, a nontraditional contacting three-stage static mixer design employing very short clear liquid residence times will be introduced.

Modeling results comparing the addition of DEA will be shown, and other high-pressure MDEA plants exhibiting DEA contamination will be reviewed. A theoretical model proposing a novel reaction method will be shown as well as a discussion of the proprietary nature of amines.

Cabin Creek

Suncor's 85-MMscfd Simonette sour-gas plant in northwestern Alberta processes sour inlet gas from low and high-pressure feeds, combines sweet gas from various other pipelines, and provides dewpoint control and compression for export through a high-pressure sales gas line.

The plant takes a high-pressure feed originating from Cabin Creek pipeline and processes the gas in a 2006 plant expansion high-pressure amine contactor, C-520. Although the plant is designed to use MDEA, a selective amine used for its ability to slip CO_2, the treated gas is consistently low in CO_2 content with little or no slip measured. The near total absorbed and subsequently stripped CO_2 causes problems for operation of the downstream Claus plant, where the acid-gas feed is low in heat content, requiring supplemental firing.

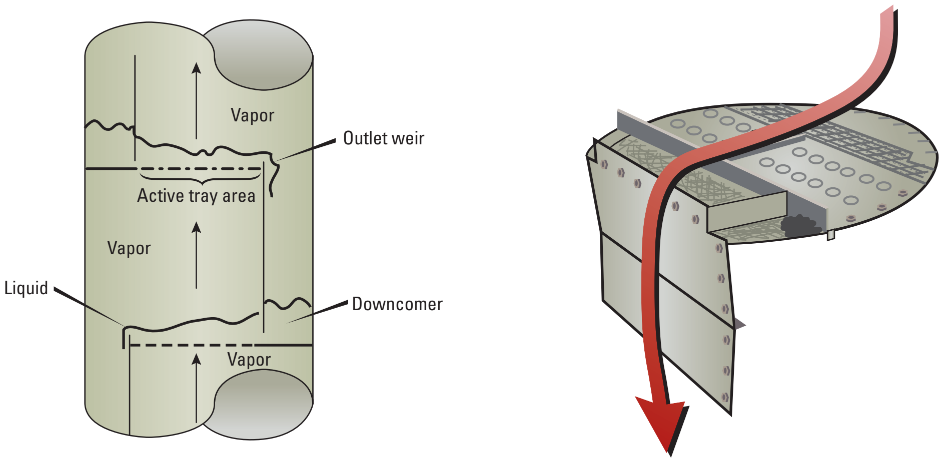
Cabin Creek inlet gas flows through HP inlet separator V-500 through filter V-510 and into the 20 tray high-pressure amine contactor C-520 operating at about 1,000 psig (68.9 barg; Fig. 1). Low-pressure inlet "Y" gas flows through inlet separator V-2-1, through filter V-200, and into the 27-tray low-pressure amine contactor C-2-1 operating at around 260 psig.

Rich amine from both C-520 and C-2-1 is gathered into amine flash drum V-2-5, the offgas flowing to a small packed column, which sweetens the gas used in the fuel gas system (not shown in Fig. 1).

The 75 psig back pressure on the drum is indirectly controlled downstream of the fuel gas contactor (not shown). V-2-5's liquid level is controlled through LV-2401, cross exchanged with lean bottoms in the lean-rich exchanger E-2-4 A/B and

TYPICAL DISTILLATION COLUMN

Fig. 2



processed by stripper C-2-2.

That stripper, a 17-stage distillation column operating with a 31-psia bottoms pressure is configured with reboiler E-2-7 using 60/40 ethylene glycol as heat medium and an aerial cooler condenser E-2-8. Condensed liquid flows through the reflux drum V-2-7 and reflux pumps P-2-2A/B, while offgas from the reflux condenser is directed to a Claus plant downstream.

Lean amine from the lean-rich exchanger flows into the amine accumulator surge tank and through to the lean amine charge pumps P-2-1 A/B, supplying the bulk flow of amine; about 140 gpm to the LP amine contactor at about 260 psig and acting as a booster to the lean-amine pumps P-525 A/B.

The lean-amine (aerial) cooler E-2-6 A/B/C reduces the temperature of the bulk flow before the stream split. A high-pressure lean amine supply delivered by the lean-amine Pumps P-525 A/B increases the 325 gpm lean-amine supply pressure to HP Contactor C-520.

Table 1 shows specific duties of the existing heat-exchange equipment, and Table 2 provides details of the distillation column.

Attempted solutions

Low CO_2 slippage can normally be compensated for by lowering the lean-amine feed point. Simonette lean-amine feeds at Trays 18 and 16 on C-520 were tried. While some slip improvement was made with Tray 16, it was less than 0.5% and at the expense of a higher H_2S specification in the treated gas.

This is a typical valve tray (Fig. 3).

During preliminary discussions between Simonette plant personnel and Jacobs Engineering team in June 2009, it was reported that interstage cooling had been experimented with, but the results were not made accessible. Although details about implementation are unknown, it was reported that increased slip was not realized after introduction of interstage cooling.

Reboiler duties approaching the design capability had been tried, increasing the stripping by offering a low acid-gas-to-amine ratio. Lab testing indicated near 0.005 mol acid gas to mol amine.[12 13] According to available literature, adequate stripping is apparently being achieved and follows the current amine supplier's recommendations.

By nature, the inlet feed gas is at 4-8° C. (40-46° F.) throughout the year. Lean amine is cooled in an aerial cooler exposed to fairly cool ambients during most of the year. At the time of the test July 3, 2008 just after midnight, the lean-amine temperature was 83.5° F.).

Operations

Based on a normal differential pressure monitored across the columns, the plant did not exhibit any foaming. There was some indication that the lean-rich exchanger was undersized, but at the flow rates exhibited, not deemed a significant problem. Additional cooling could be made up downstream at the lean (aerial) cooler. As mentioned, the lean-amine acid gas loading seemed reasonable and the plant was able to make H_2S spec sales gas.

Although the amine feed point could be dropped a few trays, the CO_2 pickup did not abate enough to warrant driving the reboiler harder for a leaner amine. It was initially speculated that the column was oversized, but it is generally viewed to be capable of slipping more CO_2 than the near zero being experienced.

System modifications

Focusing on areas that would provide an easy solution were questions about whether decreasing the lean-amine feed temperature would be able to solve the slippage. Introduction of a precocurrent contact static mixer was posed as perhaps being beneficial. Decreasing the weir height (currently at about 3 in.) or the active tray area to reduce the contact time was proposed as to whether this could increase CO_2 slippage. Modeling the system with a process simulator could possibly answer these questions.

MDEA amine systems

Selectivity in absorbing H_2S while slipping CO_2 can be normally achieved by use of a tertiary amine such as MDEA due to differences in kinetic rates. In MDEA systems, H_2S reacts quickly with the amine, while CO_2 is relatively slower allowing it to be "slipped."

CO_2 as a Lewis-type acid gas cannot react directly with MDEA, instead needing first to form carbonic acid (H_2CO_3) by combining with water. Carbonic acid then deprotonates, forming bicarbonate, while the proton is transferred to the basic amine and ultimately yields an amine bicarbonate.

This reversible reaction is kinetically dominated by the carbonic acid formation and therefore quite slow, especially at low temperatures. The MDEA-carbonate is not heat stable. At higher temperatures, the volatility of the CO_2 increases, leading to lower equilibrium loadings of the MDEA solution with CO_2 .

In contrast, H_2S converts immediately to sulfide (and bisulfide) ions via a simple instantaneous deprotonation reaction when it dissolves into an aqueous amine solution. Although this reaction is fast, it is also highly reversible and depends on solvent alkalinity. The reaction generates heat.

In design of a system to slip CO_2 , minimizing the length of time the gas mixture and solvent become intimate can promote H_2S to be absorbed more rapidly relative to CO_2 . Driving the absorption of H_2S into solution is the concentration difference between H_2S in the gas phase and the absence of the unreacted form of H_2S in the liquid.

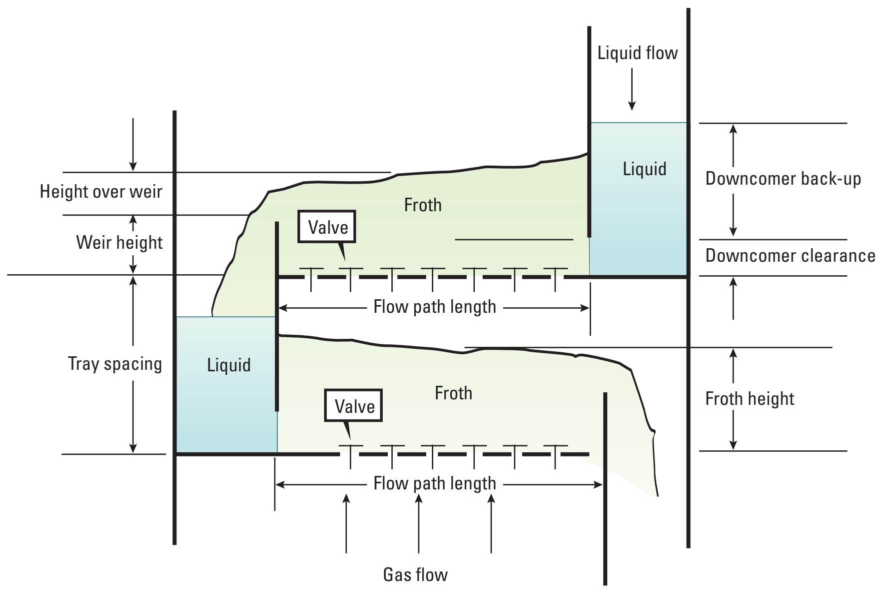
CO_2 will react with MDEA and, as discussed, at a slower rate that partially depends on temperature. Note that when H_2S reacts (quickly), the temperature of the solution increases as a result, making absorption of CO_2 easier. As more CO_2 (and H_2S) are absorbed, the alkalinity of the solution decreases, making absorption of H_2S harder by removing the ability to keep all H_2S in its anionic form with MDEA in a protonated form.

As a result, H_2S will eventually start to desorb when the protonated MDEA associated with the HS^- and $S^=$ ions starts to deprotonate (see accompanying box below).

Alternately, CO_2 will continue to react and absorb until the equilibrium loadings of H_2S and CO_2 are reached. Unfortunately, the reaction equilibrium favors keeping the CO_2 in solution and aides itself by actually releasing absorbed H_2S. Clearly, this is a complex system.

COLUMN INTERNALS

Fig. 4



BASIC MDEA/DEA REACTIONS

MDEA:			
H_2O	⇌	$H^+ + OH^-$	Disassociation of water
$R_1R_2R_3N + H_2O$	⇌	$\boxed{R_1R_2R_3NH^+} + OH^-$	
$H_2S + R_1R_2R_3N$	⇌	$\boxed{R_1R_2R_3NH^+} + HS^-$	Reaction yielding protonated MDEA
$HS^- + R_1R_2R_3N$	⇌	$\boxed{R_1R_2R_3NH^+} + S^=$	
$CO_2 + R_1R_2R_3N + H_2O$	⇌	$\boxed{R_1R_2R_3NH^+} + HCO_3^-$	Hydrolysis of carbon dioxide
$HCO_3^- + R_1R_2R_3N$	⇌	$\boxed{R_1R_2R_3NH^+} + CO_3^=$	Base catalysis of CO_2 hydration (slow)
DEA (for CO_2):			
$R_1R_2NH_2^+$	⇌	$H^+ + R_1R_2NH$	Protonation of amine
$\boxed{R_1R_2NCOO^-} + H_2O$	⇌	$R_1R_2NH + HCO_3^-$	Carbamate formation
$H_2O + CO_2$	⇌	H+ + HCO3–	Hydrolysis of carbon dioxide
HCO^-_3	⇌	$H^+ + CO_3^=$	Disassociation of bicarbonate ion
H_2O	⇌	$H^+ + OH^-$	Disassociation of water

Sources: MDEA: Reference 14; DEA (for CO_2): Reference 15.

EQUATIONS

$$CLRT = (\text{bubbling area} \times \text{froth height/liquid flow rate}) \times \text{froth gravity} \quad (1)$$

where:
Bubbling area is the exposed liquid surface area of the tray that the liquid and gas combine as the liquid traverses the flow path in Fig. 4
Froth height is the liquid level, including the froth rising above the weir.
Liquid flow rate is the total amine solution mass flow.
Froth gravity is the reduced liquid gravity as a result of gas entrainment. Froth gravity is a correction term that converts the froth height to the equivalent height of clear liquid and accounts for the fact that the aerated liquid is less dense than the clear liquid. The height over weir (h_{OW}; see Equation 2) is the difference between the froth height and the weir height.

$$h_{OW} = 0.48(V_l/L_w)^{2/3} \quad (2)$$

where:
V_l = volumetric flow rate of liquid, gpm
L_W = weir length, in.

Making the system even more complex is absorption diffusional effects for both the H_2S and CO_2 gases. Expanding on the ability of H_2S and CO_2 to be captured in the liquid and gas phases, the diffusional resistance for CO_2 occurs primarily in the liquid phase, while the resistance for H_2S occurs in the gas phase. As such, column internals can theoretically be configured to maximize mass transfer of an acid gas in one phase compared with the other, altering the relative absorption rates and maximizing CO_2 slip.

Promoting CO_2 slip

The vapor passing up through the column can be accommodated through the tray deck by various means. C-520 uses valve trays (in contrast to bubble cap or sieve trays). In valve trays, perforations are covered by liftable caps. Vapor flows lift the caps, thus self-creating a flow area for the passage of vapor. The lifting cap directs the vapor to flow horizontally into the liquid, thus providing better mixing than is possible, for example, in sieve trays (Figs. 2-4).

A popular way of interpreting a system of good mechanical design, accounting for maximizing H_2S pickup while allowing CO_2 to slip, is by clear liquid residence time (CLRT).[16] A system designed to pick up H_2S while slipping CO_2 is partly accomplished by a mechanical design allowing short liquid residence time. A generally accepted amount of CLRT for CO_2 slip applications is 2 sec (see Equation 1 in accompanying box at top of this page).[17]

One model that can be used to calculate liquid height-over-weir is the Francis weir formula (Equation 2). Bolles further published a correction factor used for segmental downcomers.[18] Note that the relationship in Equation 2 is without the weir constriction factor effect.

Further work that estimated froth gravity, however, may not be totally accurate in its depiction of CLRT since being applicable to sieve trays.[19] A relationship was proposed by Colwell, also for predicting froth density on sieve trays, uses an iterative method.[20] Kister writes that development of a clear liquid height correlation for valve trays is inhibited by the measurement of the clear liquid height.[21]

As Equation 1 shows, in theory, CLRT is indirectly proportional to the total supplied amine solution flow rate and directly proportional to tray surface area and froth depth. It would appear that decreasing the CLRT by increasing the flow rate would not subsequently increase CO_2 slip as found in earlier experience from the Waveland plant in Mississippi.[22] This may be as a result of the increased circulation rate holding the temperature cooler in the column.

In design of a high CO_2 slip ratio, it is traditionally thought important to minimize the CLRT by mechanical means. This can be accomplished in different ways or in combination, such as keeping the active area low, reducing the weir height, or keeping the reacting amine flow high.

A particular note can be made with respect to froth height. It is generally believed that the gravity of the froth changes continuously as the flowing gas, entering from the bottom of the tray, is entrained within the liquid. A density gradient further complicates calculation of froth density.

INLET FEED GAS COMPOSITIONS

Table 3

Component	HP feed, % Design	HP feed, % Current	LP feed, % Current
N_2	0.28	0.322	0.932
CO_2	3.19	2.033	1.108
H_2S	2.23	3.063	5.712
C_1	92.58	90.585	79.183
C_2	1.33	2.896	8.339
C_3	0.19	0.630	2.702
$i\text{-}C_4$	0.05	0.123	0.370
$n\text{-}C_4$	0.03	0.149	0.755
$i\text{-}C_5$	0.02	0.053	0.238
$n\text{-}C_5$	0.01	0.038	0.245
C_6	0.02	0.037	0.212
C_{7+}	0.07	0.071	0.204
Total (dry)	**100.00**	**100.00**	**100.00**

Process simulation

To answer whether plant simulation could offer any insights for improvements in CO_2 slip, operators modeled the system using actual column dimensions with commercially available process simulators specifically made for amine applications. Flow rates and field modifiable parameters were varied with effects noted.

- *HP inlet feed composition.* The initial design was based on an inlet feed composition 2.23% H_2S and accompanying CO_2 concentration of 3.19%. Feed compositions reported by gas chromatograph on July 3, 2008, downstream of the Cabin Creek inlet separator V-500 were 3.63% H_2S and 2.03% CO_2. Table 3 summarizes feed compositions including the inlet fed to the low-pressure amine contactor.

• *Feed temperature, pressure.* The original plant was designed for an inlet temperature and pressure of 1,000 psig at 4.4° C. Current pressure and temperature levels are recorded as within that range, falling to 923.8 psig and a slight increase to 7° C. on July 3, 2008.

• *Feed flow rate.* The original inlet flow rate was designed for 85 MMscfd. Current flow rates range around 71 MMscfd. Table 4 below lists the flows encountered on July 3, 2008, for the high-pressure and low-pressure amine contactors. Flow values appeared to be constant over a 12-hr period given the intervals reported.

• *Lean-amine flow rates.* Flow rates were described previously. Sample analysis by INEOS indicated the acid components to amine mol/mol amounts in Table 5.

• *Lean-amine loading.* Lean loading (mol acid gas to mol MDEA) had been analyzed the preceding May and by an earlier sample taken in January.[12 13] As these samples represent an average stripping level in day-to-day operations, this is in fairly good agreement with recommended values.[23]

Lean-amine loadings, being a function of the reboiler duty in the simulations, were specified or adjusted in order to compare with sampled data.

• *Lean-amine composition.* Table 6 shows a small amount of DEA that, over a period of 4 months, appears increasing. The plant has upstream chemical addition that was at the time in 2008 supplied by nonblanketed storage tanks, thought to be the source of oxygen, which may have led to MDEA degradation into the DEA component. Currently, work is under way to identify the sources and eliminate air infiltration. Further discussion of DEA's role in CO_2 pickup appears presently.

• *Rich-amine loading.* Typical rich loadings for amine systems using MDEA are 0.2-0.55.[23] It is worthwhile to note that the typical values cited are general design constraints representing acceptable concentrations with respect to flowing velocities of typical line sizes.

Real values are best correlated to actual resulting velocities in selected line and equipment flow paths that, beyond certain acceptable figures, would have the effect of stripping oxide layers, resulting in accelerated corrosion.

• Mechanical equipment parameters have already been stated.

CURRENT FLOW RATES Table 4

	C-520	C-2-1
Flow rate, MMscfd	1,753 (61.9)	204 (7.19)

LEAN LOADING* Table 5

Component	May 15, 2008	Jan. 21, 2008
CO_2	0.0004	0.0002
H_2S	0.0049	0.0040

*By INEOS sample analysis.

INEOS SOLVENT ANALYSIS Table 6

Component	Jan. 21, 2008	May 15, 2008
Bicine, ppm wt	1,513	1,631
Acetate, ppm wt	1,840	2,525
Formate, ppm wt	1,854	1,980
Chloride, ppm wt	30	40
Sulfate, ppm wt	1,230	1,590
Oxalate, ppm wt	245	265
Phosphate, ppm wt	<25	<25
Thiosulphate, ppm wt	65	85
Thiocyanate, ppm wt	<25	<25
MDEA, wt %*	47.5	46.7
DEA, wt %*	1.12	1.4

*By gas chromatograph.

Preliminary simulation results

Before actual gas compositions or plant operating parameters could be obtained, earlier work involved changing some parameters to monitor the effects on CO_2 slip using the original design case conditions (Table 4). Parameters were selected based on field modifiable items or whether inlet feed temperatures had the effect of invoking significant changes.

Simulator No. 1 initially employed is a popular, amine-specific simulator used by many in the industry. Weir height, amine circulation rate, a combination of circulation rate and weir height, inlet feed temperature, amine solution strength, and a combination of inlet feed temperature and amine solution strength were experimented with for the high-pressure amine contactor handling the majority of the treated gas.

The particular simulator used did not allow free configuration of the components such as modeling of the additional low pressure amine contactor or combining the rich amine into a common stripper. A straight 50 wt % MDEA solution was applied.

Table 7 suggests that decreasing the flow rate may improve the CO_2 slip, contrary to expectations derived from Equation 1 in relation to CLRT. Directionally, CO_2 slip is shown to improve when the weir height (exaggerated) is decreased.

Using a hotter feed also seemed to increase slip, contrary to what theory would lead one to believe without looking deeper into actual column temperature bulge, which could indicate release of CO_2 from solution greater than 130° C. Decreasing solution strength also increased the slippage. The obtained results did not inspire much trust, given that the plant, operating close to the design point, was not getting similar slip or treated-gas outlet concentrations. Getting total comparative results for all the cases was not pursued.

Simulator comparisons

During the course of the study, many preliminary cases were compiled and compared, yielding highly varied results. It was hard to tell which simulator produced the most reliable values without correlation to existing plant data or from a similar designed amine plant.

Once official plant data became available, specific column parameters as well as the inlet feed compositions

PROCESS SIMULATOR NO. 1: PARAMETERS Table 7

	Parameter	Case 1	Case 2	Case 3	Case 4
	Amine flow rate, gpm STD	400	400	320	320
	Weir height, in.	3.125	0.125	3.125	0.125
	Weir length, ft	5	5	5	5
Feed, 40° F.	CO_2 in outlet, mol fr	0.010	0.013	0.015	0.021
	H_2S in outlet, mol fr	2 e-6	2 e-6	1.3 e-5	2 e-6
	CO_2 slip, %	31.3	40.7	47	65.8
Feed, 100° F.	CO_2 in outlet, mol fr	0.012	0.021	0.018	0.019
	H_2S in outlet, mol fr	2 e-6	2 e-6	4.3 e-5	8.1 e-5
	CO_2 slip, %	37.6	65.8	56.4	60.0
MDEA 30%	CO_2 in outlet, mol fr	0.019			
	H_2S in outlet, mol fr	2 e-6			
	CO_2 slip, %	60			
MDEA 30% & 100° F.	CO_2 in outlet, mol fr	0.019			
	H_2S in outlet, mol fr	2 e-6			
	CO_2 slip, %	60			

were added to the models. Up to this time, a mixture of design conditions and ultimate feed characteristics were used in order to observe which parameters could be changed to increase CO_2 slip drastically. No previous results were conclusive because, for example, many of the simulators used were off by a couple orders of magnitude in their predictions of CO_2 slip.

- Simulator No. 2 is an amine-specific simulator, with features allowing the use of mixed amines and for modeling of column internals including trayed and packed columns. It offered very good convergence characteristics. While actual trays could be modeled, the process vendor suggested using ideal stages with actual column and tray dimensions.
- Simulator No. 3 is a commonly used simulator specifically designed for amine systems. It allows for mixed amines and modeling of column and tray dimensions. This simulator offered the ability to model some of the heat-stable salts in solution. Convergence ability was slightly poorer than Simulator No. 2 but was very effective after gaining experience with some operating anomalies.
- Simulator No. 4 is a general purpose process simulator that many use for modeling amine systems and was used in the original design of Simonette. It offers some limited blended-amine capability and physical parameter manipulation.
- Simulator No. 5 has recently appeared on the market and offers modeling of blended amine and physical column and tray dimensions.

To reiterate: Simulator No. 1 was not used in the comparison table because it had limited capability in modeling the total Simonette amine system.

While an attempt was made to make an accurate comparison between simulation programs, it was found that common molecular components could not be specified. (Table 6 shows the results of INEOS amine analysis performed on the dates shown, showing some of the heat-stable salts prevalent in the solution.)

Simulator No. 3, for example, allowed many of the heat-stable salts to be input, whereas the others did not include these in the component selection. As such, a complete comparison across the board showing the effects of heat-stable salts could not be made but was included as a comparison case by itself to demonstrate how these components may directionally affect the system's behavior.

Simulator No. 4 did not allow the addition of sulfates, modeled as a small amount of sulfuric acid in the other simulator cases.

Not all simulators allowed the modeling of actual trays. Simulator No. 2 showed the most accurate values in relation to actual measured plant data but modeled with theoretical stages, that combined with actual column tray dimensional data (weir heights, column diameters, weir lengths/active areas, etc.), as recommended by the process vendor to provide the most accurate results.

Simulated CO_2 slip

Simulator No. 3 was adjusted to achieve an acid-gas loading similar to the other cases. Driving the reboiler harder to attain 0.005 acid-gas loading, however, produced much higher reboiler duties than the existing equipment was capable of. Notably, the results indicated less duty was required when balancing the acid-gas component in the sweetened gas, which was brought down to considerably low levels.

All cases except for Simulator No. 2 showed the amount of CO_2 slip to be roughly in the range of 25-65%, inconsistent with field results indicating 0.05-0.1%. Discussions with industry spokesmen revealed no reasonable explanation for why the simulation results varied with respect to actual CO_2 slip vs. modeled results.

As one amine technical expert put it, by virtue of the specified selective amine used, C-520 would have required 50 trays to account for the experienced CO_2 pickup. One amine supplier also speculated that there was no accountable reason why at least 30% slip could be achieved. ✦

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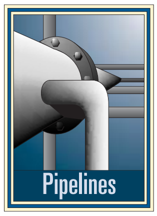
Oil sands export pipeline capacity exceeds supply through 2015-16

Christopher E. Smith
Pipeline Editor



More than 1 million b/d of extra crude pipeline capacity will run from western Canada by the end of 2010. Matching supply, however, will not be online until 2016, according to the most recent estimates from the Canadian Association of Petroleum Producers.[1]

This gap, and the general economic slowdown which helped create it, have caused development of export pipeline projects out of Canada beyond the three already approved and in construction (TransCanada Keystone, Enbridge Alberta Clipper, and TransCanada Keystone

Extension) to slow, with some projects tabled indefinitely.

The accompanying table provides an overview of the new-construction oil sands crude pipeline projects. This article will look at oil sands crude supply and demand and then examine in greater detail some of the larger sands pipeline projects currently moving forward.

Supply, demand

The primary source of crude for any of these pipeline projects will be the Alberta oil sands. The Alberta Energy Resources and Conservation Board reports 170.4 billion bbl of remaining established bitumen reserves in the oil sands.[2]

The Hardisty, Alta., crude hub has a total inbound pipeline capacity of about 2.8 million b/d, supplemented by rail and truck deliveries. It also has 18 million bbl of storage.[3] TransCanada's Section 52 application for its Keystone XL pipeline project states the Hardisty hub will provide the pipeline with access to a wide variety of both light and heavy crudes for shipment to the US Gulf Coast. Fig. 1 shows inbound and outbound flows from Hardisty as well as the capacities of major storage operators at the hub.

As part of its filings with the NEB, TransCanada had Purvin & Gertz Inc. (PGI) conduct an assessment of the potential supply-demand balance between Western Canadian crude oil and US gulf refineries. PGI forecast supply growth between 2007 and 2017 of 1.55-2.42 million b/d.4 The assessment also noted the US Gulf Coast refining market currently only received 65,000 b/d of Canadian crude via the Pegasus pipeline but had coking capacity sufficient to run large amounts of heavy crude.

PGI also noted US Gulf Coast capacity to use heavy crude had been expanding at the same time supplies of heavy crude have been falling. For example, Motiva is conducting a large expansion at its Port Arthur refinery, adding 325,000 b/d of new crude capacity and 95,000 b/d of new coking capacity by 2011.[5]

PGI estimated the US gulf market could absorb a minimum of 500,000 b/d of Canadian crude. PGI also estimated that without Keystone XL, heavy crude oil pipeline capacity out of Western Canada would reach capacity by 2015.[6]

Keystone

TransCanada Corp.'s 2,148-mile Keystone pipeline project will transport crude oil from Canada to the US Midwest. In addition to 1,379 miles of newbuild US line, Keystone includes additions to existing Canadian pipelines and mainline flow reversals. It is expected to start in December 2009 with the capacity to deliver 435,000 b/d from Hardisty to the US at Wood River and Patoka, Ill.

TransCanada plans to extend the line to Cushing, Okla., starting fourth-quarter 2010, expanding to 590,000 b/d. The project has secured firm long-term contracts totaling 495,000 b/d for an average of 18 years (OGJ, Feb. 9, 2009, p. 56).

New pipeline will have a 30-in. OD to Illinois and 36-in. OD from the Nebraska-Kansas border to Cushing, buried to a minimum depth of cover of 4 ft. The estimated operating pressure of the new pipeline sections will be 1,440 psi. Existing pipeline converted to crude oil transportation will operate at its current approved allowable operating pressure of 880 psig.

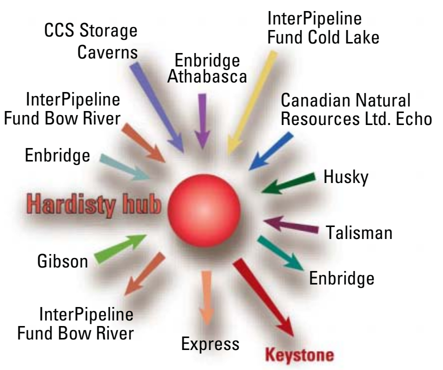
New pipeline construction of 101 km in Manitoba was ~98% complete as of April 15, 2009. In Alberta, 202 of 280 km had been welded, with overall work ~50% complete. Conversion of existing pipelines was ~60% complete. TransCanada expects mechanical completion of Canadian pump stations by fourth-quarter 2009. Construction of three storage tanks, a pump station, and meter manifold piping at the Hardisty terminal was ~40% complete as of TransCanada's Apr. 15 update.[7]

The same update described Keystone's two spreads in North and South Dakota as 90% completed at end-2008.

As of June 7, 2009, the weekly pipeline construction progress report filed

Hardisty terminal flows, storage

Fig. 1



Total storage capacity: 18 million bbl

Major storage operators, capacities; million bbl	
Gibson:	2.8
Husky:	2.3
EMI:	7.5
EPI:	2
CCS:	3
Express:	0.6

Source: TransCanada Keystone Pipeline GP Ltd.

Oil sands crude export pipelines

Destination	Project	Route	Capacity, b/d	OD, in.	Completion
East	TransCanada Keystone	Hardisty, Alta., to Wood River-Patoka, Ill.	435,000	—	December 2009
	Keystone Extension	Wood River-Patoka to Cushing, Okla.	590,000 (total, including above)	—	Fourth-quarter 2010
	TransCanada DilBit pipeline	Fort McMurray, Alta., to Hardisty	400,000	—	2012-14
	Enbridge Alberta Clipper	Hardisty to Superior, Wis.	450,000 (expandable to 800,000)	36	July 2010
	Enbridge Southern Access Extension	Flanagan, Ill., to Patoka	400,000	36	2012
	Bow River	Hardisty to Montana	30,000	—	First-quarter 2010
	Enbridge Trailbreaker	Sarnia, Ont., to Montreal	215,000	—	—
	Sunoco	Buffalo, NY, to Philadelphia	400,000	24	—
Gulf Coast	BP-Enbridge Gulf Access	Flanagan to Port Arthur-Nederland, Tex.	400,000	—	2012
	Sunoco	Cushing to Nederland	300,000	—	—
	ExxonMobil-Enbridge	Patoka to Beaumont, Tex.	445,000 (expandable to more than 550,000)	30	—
	TransCanada Keystone XL	Hardisty to Port Arthur-Houston	700,000 (expandable to 1.5 million for full Keyston system)	36	2012
	Altex Energy	Alberta to Port Arthur-Beaumont	425,000 (expandable to 1 million)	36	—
West	Kinder Morgan TMX2	Edmonton to Kamloops, BC	80,000	—	2012
	TMX3	Kamloops to Anacortes, Wash.	320,000	—	2013
	K-M Northern Leg Expansion	Rearguard, BC, to Kitimat, BC	400,000	—	2014
	Enbridge Northern Gateway	Edmonton to Kitimat	500,000	36	—
	TransCanada AB-California	Alberta to California	400,000	—	2016

Source: Canadian Association of Petroleum Producers

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KEYSTONE PIPELINE SYSTEM

Fig. 2

by TransCanada with the US Federal Energy Regulatory Commission (FERC) covered work under way in South Dakota between mileposts 217.8 and 438.0. Activities included:

- Erosion, sedimentation control; cleanup.
- Surveying.
- Top soiling, grading.
- Stringing, bending pipe sections.
- Welding, coating field joints.
- Road bore.
- Potholing.
- Mobbing equipment to the right-of-way (ROW).
- Clearing.
- Coating tests.

Work also progressed on four pump stations along the same stretch of pipeline.

TransCanada plans work on a total of six spreads in South Dakota, Nebraska, Kansas, Missouri, and Illinois during 2009. Land easements for its 2009 construction plans are 99% complete. The company has begun work on a total of 23 US pump stations, scheduled for mechanical completion in fourth-quarter 2009.[7]

XL

TransCanada announced plans in July 2008 for the Keystone Gulf Coast Expansion Project (Keystone XL), providing 700,000 b/d additional capacity from western Canada to the US Gulf Coast by 2012. Keystone XL has secured firm contracts for 380,000 b/d for an average of 17 years from shippers.

Keystone XL includes 1,980 miles of 36-in. OD line starting in Hardisty and extending to a delivery point near existing terminals in Port Arthur, Tex. (Fig. 2). XL will also include 41 pump stations—33 in the US and 8 in Canada—situated at roughly 50-mile intervals. Each pump station will use two to three 6,500 hp electric pumps, providing a total of up to 19,500 hp/station. Each station could be expanded to 32,500 hp to boost line capacity.

Subject to shipper support, Keystone XL will include an additional 50-mile lateral to Houston. TransCanada anticipates beginning construction in 2010, pending regulatory approvals, and intends to start the line in 2012. Construction will take place in both frozen and unfrozen conditions, at an average rate of 2-4 km/day, according to TransCanada's Section 52 application for the project.

Canada's National Energy Board (NEB) has scheduled an oral hearing on an application by TransCanada to construct and operate the 327-mile Canadian portion of Keystone XL, extending from Hardisty to the US border at Monchy, Sask., for Sept, 15, 2009.

Canadian construction will include two major water crossings: Red Deer River and South Saskatchewan River, both in Alberta. A feasibility report completed by TransCanada and included in its Section 52 application showed horizontal directional drilling could be used for both crossings. In the event HDD could not be completed, TransCanada would use a two-stage coffer damn isolated crossing technique for Red Deer and either this technique or open cut construction for South Saskatchewan. HDD work will take place in late 2010 and early 2011.[8]

ENBRIDGE NORTHERN GATEWAY PIPELINE Fig. 3

Source: Enbridge Northern Gateway Pipelines

TransCanada's overall Canadian construction schedule calls for:

• Pipeline construction from fourth-quarter 2010 to third-quarter 2012.

• Construction of the Hardisty B terminal and pump station from third-quarter 2010 to second-quarter 2012.

• Intermediate pump station construction from third-quarter 2011 to third-quarter 2012.

• Commissioning and line fill from second-quarter 2012 to fourth-quarter 2012.[9]

The US portion starts at Morgan, Mont., extending 836 miles of new-build pipeline southeast through South Dakota and Nebraska to Steele City. At Steele City, Keystone XL will connect to the 36-in. planned extension of Keystone and run 296 miles into Cushing. The final 478-mile newbuild stretch from Cushing to Port Arthur would complete the line.

Enbridge

Enbridge expects its 1,000-mile, 36-in. OD Alberta Clipper pipeline to enter service between Hardisty and Superior, Wis., in mid-2010, initially moving 450,000 b/d but with ultimate capacity of as much as 800,000 b/d.

The company has also renewed plans to build the 525,000-b/d Northern Gateway Pipeline from near Edmonton to a tanker terminal near Kitimat, BC (Fig. 3), for shipment to China, other parts of Asia, and California. Enbridge put the 1,170-km, 36-in. OD project on hold in December 2006 to focus on completing its Southern Access-Southern Lights project. A line running parallel to the crude line would ship 193,000 b/d of condensate from the coast to Alberta.

Enbridge expects to build Northern Gateway in 2012-14, pending regulatory approval of filings made this year. Commissioning and start-up would occur 2014-15. Enbridge would also operate the Kitimat terminal. The terminal would have 2 mooring berths, 14 storage tanks for petroleum and condensate, and be called on by roughly 225 ships/year. ✦

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Mustang Engineering,

Houston, has appointed Charles R. (Chuck) Johnston as an advanced process control specialist in its automation and control business unit. He will be responsible for extending Mustang's offering and expertise in advanced process control applications in refining and other industries. He has more than 25 years experience in all facets of the advanced process control specialty, including business development, project management, product development, project implementation, and training. Johnston was a co-developer of the dynamic matrix control technology, widely recognized and applied in the refining and petrochemicals industries.

Johnston

Mustang, part of the UK-based Wood Group, specializes in design, engineering, procurement, project management, and construction management to the upstream oil and gas, midstream, pipeline, automation and control, refining and petrochemicals, and process and industrial sectors.

Stora Enso Oyj,

Helsinki, and Neste Oil have inaugurated a biomass-to-liquids demonstration plant using forestry residues at Varkaus, Finland. Their 50-50 joint venture NSE Biofuels Oy was established to develop and commercialize technology to produce biocrude for renewable diesel fuel. The plant's process units will handle drying of biomass, gasification, gas cleanup, and testing of Fischer-Tropsch catalysts. Finnish government agencies provided funding for the technology development and financing for the demonstration plant.

Stora Enso is a leading global paper, packaging, and forestry products company.

Neste Oil is an oil refiner-marketer with a controlling interest held by Finland's government.

SNF Group,

Andrezieux, France, has announced its decision to build a new water-soluble polymers manufacturing plant in Iberville Parish, La. The plant will have capacity to produce 250,000 tons/year of polyacrylamides, mainly for use as thickeners in the growing enhanced oil recovery market. Start-up is slated for mid-2011. SNF is pursuing numerous EOR projects over the world and has developed a unique set of technologies, including patented surface equipment and proprietary polymer protection packages and control methods, to help improve the performance of polymer injections.

SNF is the leading producer of polyacrylamides used as thickeners and flocculents.

Boots & Coots Inc.,

Houston, has joined the broad-market Russell 3000 Index, moving up from the Russell Microcap. The index each year captures the 4,000 largest US indexes as of the end of May, ranking them by total market capitalization. The ranking gives Boots & Coots greater exposure to a broader set of investors.

Boots & Coots provides a suite of integrated pressure control services to onshore and offshore oil and gas exploration companies around the world.

Statistics

Imports of crude and products

	Districts 1–4 6-26 2009	Districts 1–4 6-19 2009	District 5 6-26 2009	District 5 6-19 2009	Total US 6-26 2009	Total US 6-19 2009	Total US *6-27 2008
	1,000 b/d						
Total motor gasoline	917	955	62	16	979	971	1,356
Mo. gas. blending comp.	668	655	62	2	730	657	857
Distillate	165	289	0	0	165	289	149
Residual	305	179	0	27	305	206	369
Jet fuel–kerosine	25	78	36	20	61	98	66
Propane–propylene	89	93	1	2	90	95	105
Other	196	13	(6)	55	190	68	677
Total products	**2,365**	**2,262**	**155**	**122**	**2,520**	**2,384**	**3,579**
Total crude	**8,191**	**8,370**	**1,172**	**914**	**9,363**	**9,284**	**10,168**
Total imports	**10,556**	**10,632**	**1,327**	**1,036**	**11,883**	**11,668**	**13,747**

*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

	*7-03-09	*7-04-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	74.79	151.56	–76.77	–50.7
Brent crude	67.97	142.88	–74.91	–52.4
Crack spread	6.82	8.68	–1.86	–21.4
FUTURES MARKET PRICES				
One month				
Product value	76.41	156.35	–79.94	–51.1
Light sweet crude	69.36	142.46	–73.11	–51.3
Crack spread	7.06	13.90	–6.84	–49.2
Six month				
Product value	77.81	157.09	–79.28	–50.5
Light sweet crude	72.80	143.99	–71.19	–49.4
Crack spread	5.02	13.11	–8.09	–61.7

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

Purvin & Gertz LNG netbacks—July 3, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.73	4.06	5.95	3.96	4.61	5.87
Everett	3.08	1.16	2.75	1.26	1.65	3.35
Isle of Grain	3.13	1.20	2.57	1.11	1.70	2.59
Lake Charles	1.24	–0.44	1.03	–0.30	–0.13	1.79
Sodegaura	3.79	5.49	4.05	5.21	4.93	3.20
Zeebrugge	4.59	2.50	3.94	2.40	3.05	4.00

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 Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	13,933	55,178	36,670	11,651	64,592	15,515	3,795
PADD 2	81,501	49,981	24,100	7,636	31,828	1,258	23,510
PADD 3	183,105	70,581	39,315	13,555	43,743	15,323	32,149
PADD 4	16,806	6,025	1,938	524	3,147	248	[1]1,328
PADD 5	54,848	29,473	23,743	8,506	11,689	4,921	—
June 26, 2009	**350,193**	**211,238**	**125,766**	**41,872**	**154,999**	**37,265**	**60,782**
June 19, 2009	**353,853**	**208,905**	**125,444**	**41,728**	**152,103**	**37,736**	**57,139**
June 27, 2008[2]	**299,776**	**210,857**	**104,150**	**39,633**	**120,685**	**40,000**	**41,358**

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

Refinery report—June 26, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Refinery output Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,397	1,366	2,418	103	383	111	58
PADD 2	3,336	3,314	2,192	204	919	56	237
PADD 3	7,457	7,254	2,856	594	2,155	256	686
PADD 4	588	582	325	33	172	12	[1]69
PADD 5	2,595	2,476	1,450	387	555	124	—
June 26, 2009	**15,373**	**14,992**	**9,241**	**1,321**	**4,184**	**559**	**1,050**
June 19, 2009	**15,384**	**15,031**	**9,224**	**1,443**	**4,069**	**597**	**1,094**
June 27, 2008[2]	**15,699**	**15,413**	**9,039**	**1,564**	**4,571**	**679**	**1,117**

17,672 Operable capacity **87.0 utilization rate**

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

OGJ gasoline prices

	Price ex tax 7-1-09	Pump price* 7-1-09	Pump price 7-2-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	210.8	257.3	413.2
Baltimore	213.4	255.3	403.6
Boston	217.4	259.3	406.6
Buffalo	209.4	270.3	421.6
Miami	223.7	275.3	423.6
Newark	213.7	246.3	396.0
New York	204.4	265.3	413.9
Norfolk	212.4	250.8	395.6
Philadelphia	215.6	266.3	413.1
Pittsburgh	214.5	265.2	403.3
Wash., DC	227.9	266.3	413.2
PAD I avg	214.8	261.6	409.4
Chicago	238.5	302.9	444.4
Cleveland	224.5	270.9	400.4
Des Moines	221.6	262.0	399.4
Detroit	227.5	286.9	410.4
Indianapolis	214.5	273.9	400.3
Kansas City	207.3	243.3	396.4
Louisville	228.0	268.9	403.5
Memphis	206.8	246.6	389.8
Milwaukee	228.6	279.9	412.5
Minn.-St. Paul	221.0	265.0	401.4
Oklahoma City	202.9	238.3	387.1
Omaha	199.4	244.7	397.8
St. Louis	205.4	241.4	393.5
Tulsa	198.6	234.0	386.3
Wichita	203.0	246.4	376.5
PAD II avg	215.2	260.3	400.0
Albuquerque	222.0	258.4	389.3
Birmingham	214.1	253.4	397.3
Dallas-Fort Worth	218.9	257.3	402.3
Houston	215.0	253.4	394.3
Little Rock	211.2	251.4	396.1
New Orleans	215.0	253.4	399.3
San Antonio	209.0	247.4	392.3
PAD III avg	215.0	253.5	395.8
Cheyenne	222.6	255.0	394.5
Denver	221.8	262.2	409.4
Salt Lake City	215.3	258.2	402.8
PAD IV avg	219.9	258.5	402.2
Los Angeles	228.2	295.3	458.3
Phoenix	218.9	256.3	425.3
Portland	234.0	277.4	433.4
San Diego	230.2	297.3	467.3
San Francisco	238.2	305.3	462.4
Seattle	235.4	291.3	442.4
PAD V avg	230.8	287.2	448.2
Week's avg.	**217.6**	**263.2**	**408.8**
June avg.	**214.6**	**260.2**	**404.2**
May avg.	**179.0**	**224.6**	**372.9**
2009 to date	**164.1**	**209.7**	—
2008 to date	**298.2**	**341.9**	—

*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

	6-26-09 ¢/gal		6-26-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	182.40	New York Harbor	169.20
Gulf Coast	177.77	Gulf Coast	169.60
Los Angeles	185.27	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	180.59	ARA	176.57
Singapore	185.50	Singapore	182.74
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	187.90	New York Harbor	145.90
Gulf Coast	183.77	Gulf Coast	148.88
Los Angeles	195.52	Los Angeles	160.19
		ARA	141.17
		Singapore	151.87

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

Baker Hughes rig count

	7-3-09	7-4-08
Alabama	4	5
Alaska	6	4
Arkansas	44	59
California	23	43
Land	23	43
Offshore	0	0
Colorado	45	111
Florida	1	1
Illinois	1	1
Indiana	4	2
Kansas	19	11
Kentucky	9	7
Louisiana	134	176
N. Land	77	74
S. Inland waters	8	20
S. Land	11	29
Offshore	38	53
Maryland	0	1
Michigan	0	1
Mississippi	9	13
Montana	0	12
Nebraska	0	0
New Mexico	40	81
New York	2	5
North Dakota	40	70
Ohio	8	13
Oklahoma	82	209
Pennsylvania	43	25
South Dakota	1	2
Texas	338	923
Offshore	2	8
Inland waters	0	2
Dist. 1	13	22
Dist. 2	14	33
Dist. 3	28	59
Dist. 4	33	95
Dist. 5	77	187
Dist. 6	46	121
Dist. 7B	13	33
Dist. 7C	12	67
Dist. 8	54	143
Dist. 8A	6	27
Dist. 9	17	42
Dist. 10	23	84
Utah	16	44
West Virginia	20	19
Wyoming	31	76
Others—HI-1; NV-2; VA-5;	8	7
Total US	**928**	**1,921**
Total Canada	**165**	**388**
Grand total	**1,093**	**2,309**
US Oil rigs	229	373
US Gas rigs	688	1,539
Total US offshore	42	63
Total US cum. avg. YTD	**1,131**	**1,821**

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	7-3-09 Rig count	7-3-09 Percent footage*	7-4-08 Rig count	7-4-08 Percent footage*
0-2,500	37	5.4	84	3.5
2,501-5,000	68	61.7	146	45.2
5,001-7,500	113	21.2	255	15.6
7,501-10,000	192	5.2	469	3.1
10,001-12,500	181	9.3	486	2.8
12,501-15,000	146	—	329	—
15,001-17,500	114	—	139	—
17,501-20,000	48	—	84	—
20,001-over	29	—	38	—
Total	**928**	**10.2**	**2,030**	**6.7**
INLAND	12		32	
LAND	877		1,937	
OFFSHORE	39		61	

*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]7-3-09	[2]7-4-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	660	651
California	644	647
Colorado	62	66
Florida	5	5
Illinois	28	26
Kansas	99	106
Louisiana	1,415	1,296
Michigan	15	15
Mississippi	60	60
Montana	90	85
New Mexico	161	163
North Dakota	189	161
Oklahoma	170	173
Texas	1,315	1,350
Utah	55	60
Wyoming	149	143
All others	65	76
Total	**5,201**	**5,104**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US crude prices

	7-3-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	67.00
California-Kern River 13°	58.30
Lost Hills 30°	66.60
Wyoming Sweet	56.23
East Texas Sweet	62.75
West Texas Sour 34°	57.25
West Texas Intermediate	63.25
Oklahoma Sweet	63.25
Texas Upper Gulf Coast	56.25
Michigan Sour	55.25
Kansas Common	62.75
North Dakota Sweet	52.75

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

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

World crude prices

$/bbl[1]	6-26-09
United Kingdom-Brent 38°	68.52
Russia-Urals 32°	68.39
Saudi Light 34°	65.94
Dubai Fateh 32°	69.14
Algeria Saharan 44°	68.58
Nigeria-Bonny Light 37°	69.80
Indonesia-Minas 34°	72.41
Venezuela-Tia Juana Light 31°	67.59
Mexico-Isthmus 33°	67.48
OPEC basket	68.21
Total OPEC[2]	67.73
Total non-OPEC[2]	67.62
Total world[2]	67.68
US imports[3]	65.92

[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]

	6-26-09	6-19-09	6-26-08	Change, %
	bcf			
Producing region	1,001	997	700	**43.0**
Consuming region east	1,289	1,234	1,108	**16.3**
Consuming region west	431	420	298	**44.6**
Total US	**2,721**	**2,651**	**2,106**	**29.2**
	Apr. 09	**Apr. 08**	**Change, %**	
Total US[2]	**1,903**	**1,436**	**32.5**	

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Apr. 2009	Mar. 2009	4 month average production 2009	4 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	Apr. 2009	Mar. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	625	627	624	621	4	0.6	117.0	121.8	462.74
Bolivia	40	40	40	41	–1	–1.4	41.0	42.0	163.00
Brazil	1,940	1,943	1,920	1,774	146	8.2	28.0	31.0	116.00
Canada	2,651	2,614	2,648	2,571	77	3.0	408.9	470.7	1,847.85
Colombia	649	646	640	562	78	13.8	21.0	22.0	86.00
Ecuador	480	460	480	500	–20	–4.0	2.0	2.0	8.00
Mexico	2,642	2,652	2,661	2,875	–215	–7.5	208.9	215.5	840.51
Peru	97	107	104	69	35	50.5	8.6	9.6	35.20
Trinidad	110	110	110	114	–4	–3.6	114.4	115.0	448.35
United States	5,370	5,270	5,269	5,127	143	2.8	1,808.0	1,874.0	7,234.00
Venezuela[1]	2,120	2,100	2,125	2,380	–255	–10.7	68.0	70.0	268.00
Other Latin America	83	83	83	83	—	–0.5	5.4	5.5	21.66
Western Hemisphere	**16,808**	**16,652**	**16,704**	**16,716**	**–12**	**–0.1**	**2,831.3**	**2,979.2**	**11,531.31**
Austria	16	17	17	17	—	—	4.5	4.8	19.40
Denmark	273	275	277	290	–14	–4.6	22.2	16.1	92.64
France	18	18	18	21	–2	–9.9	2.7	2.8	11.10
Germany	57	58	58	62	–4	–6.3	43.5	46.4	181.87
Italy	87	90	86	108	–22	–20.0	22.0	24.0	93.00
Netherlands	27	27	28	39	–11	–27.7	260.0	280.0	1,270.00
Norway	2,072	2,238	2,191	2,181	10	0.5	309.0	342.6	1,360.69
Turkey	46	46	42	39	3	7.0	0.0	0.0	0.00
United Kingdom	1,476	1,464	1,459	1,490	–31	–2.1	200.7	200.9	841.54
Other Western Europe	3	3	3	4	–1	–25.9	1.6	1.7	9.06
Western Europe	**4,075**	**4,236**	**4,180**	**4,251**	**–71**	**–1.7**	**866.2**	**919.3**	**3,879.30**
Azerbaijan	950	920	923	939	–16	–1.7	30.0	35.0	130.00
Croatia	14	14	14	15	–1	–6.7	5.2	5.3	20.96
Hungary	14	13	14	14	—	–2.3	6.9	7.2	31.04
Kazakhstan	1,250	1,200	1,238	1,188	50	4.2	100.0	100.0	400.00
Romania	90	90	90	95	–5	–5.3	18.0	19.0	73.00
Russia	9,840	9,770	9,770	9,743	28	0.3	1,500.0	1,700.0	6,600.00
Other FSU	500	400	450	400	50	12.5	350.0	350.0	1,450.00
Other Eastern Europe	43	44	44	50	–6	–11.1	19.7	21.0	82.63
Eastern Europe and FSU	**12,702**	**12,451**	**12,542**	**12,443**	**99**	**0.8**	**2,029.9**	**2,237.5**	**8,787.63**
Algeria[1]	1,250	1,220	1,248	1,388	–140	–10.1	245.0	250.0	985.00
Angola[1]	1,700	1,680	1,713	1,901	–189	–9.9	4.0	5.0	17.00
Cameroon	68	78	75	88	–13	–14.6	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	640	653	658	–5	–0.8	120.0	125.0	490.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.24
Gabon	240	240	240	225	15	6.7	0.3	0.3	1.20
Libya[1]	1,520	1,520	1,568	1,760	–193	–10.9	35.0	37.0	147.00
Nigeria[1]	1,780	1,780	1,805	2,003	–198	–9.9	85.0	88.0	343.00
Sudan	500	500	500	480	20	4.2	—	—	—
Tunisia	86	84	87	81	6	7.9	8.6	8.5	33.45
Other Africa	221	221	221	221	—	—	8.3	9.1	34.80
Africa	**8,590**	**8,548**	**8,694**	**9,389**	**–695**	**–7.4**	**506.2**	**523.0**	**2,051.69**
Bahrain	168	169	169	169	—	–0.1	26.2	23.4	96.82
Iran[1]	3,750	3,650	3,723	4,000	–278	–6.9	285.0	290.0	1,140.00
Iraq[1]	2,370	2,370	2,305	2,385	–80	–3.4	18.0	20.0	75.00
Kuwait[1,2]	2,250	2,250	2,315	2,588	–273	–10.5	36.0	38.0	148.00
Oman	720	720	723	723	—	—	55.0	60.0	229.00
Qatar[1]	780	740	763	843	–80	–9.5	220.0	230.0	890.00
Saudi Arabia[1,2]	7,860	8,210	7,960	8,975	–1,015	–11.3	205.0	220.0	845.00
Syria	380	380	383	388	–5	–1.3	17.0	18.0	69.00
United Arab Emirates[1]	2,250	2,250	2,278	2,630	–353	–13.4	128.0	132.0	515.00
Yemen	280	280	283	315	–33	–10.3	—	—	—
Other Middle East	—	—	—	—	—	104.4	6.1	7.5	32.30
Middle East	**20,809**	**21,019**	**20,899**	**23,014**	**–2,115**	**–9.2**	**996.3**	**1,038.9**	**4,040.12**
Australia	483	472	480	423	57	13.5	122.9	112.4	463.97
Brunei	140	155	152	170	–18	–10.5	32.0	37.0	139.36
China	3,805	3,381	3,660	3,769	–109	–2.9	242.8	241.1	984.86
India	655	686	648	678	–30	–4.4	91.0	87.9	335.20
Indonesia[1]	840	850	855	860	–5	–0.5	190.0	200.0	790.00
Japan	15	18	18	19	–1	–4.3	9.7	11.8	45.48
Malaysia	750	740	743	770	–28	–3.6	135.0	140.0	545.00
New Zealand	50	50	45	61	–16	–26.2	12.0	12.5	46.90
Pakistan	64	65	65	67	–3	–3.8	121.6	127.8	489.82
Papua New Guinea	40	40	40	43	–3	–7.5	0.9	1.0	3.80
Thailand	238	253	246	218	28	12.8	31.5	40.3	134.34
Vietnam	300	300	275	298	–23	–7.6	14.5	15.0	58.00
Other Asia-Pacific	35	35	35	39	–4	–10.6	88.5	96.5	373.00
Asia-Pacific	**7,414**	**7,045**	**7,260**	**7,413**	**–153**	**–2.1**	**1,092.4**	**1,123.2**	**4,409.72**
TOTAL WORLD	**70,396**	**69,951**	**70,280**	**73,227**	**–2,947**	**–4.0**	**8,322.3**	**8,821.2**	**34,699.77**
OPEC	28,110	28,230	28,280	32,211	–3,931	–12.2	1,331.0	1,382.0	7,481.00
North Sea	3,841	3,998	3,947	3,980	–32	–0.8	609.8	643.5	2,675.23

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

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In need of money, the US government takes aim at LIFO

Beware the government asserting principle but needing money.

The Obama administration asserted principles of sorts when it proposed in its budget for fiscal 2010 to eliminate last-in, first-out (LIFO) inventory accounting.

In its explanation of the proposal, the Treasury Department called LIFO "a tax deferral opportunity" and "a complex and burdensome accounting method." It also called LIFO an impediment to US implementation of International Financial Reporting Standards, which prohibit LIFO accounting.

The Editor's Perspective

by Bob Tippee, Editor

Then there's the money: $61 billion to federal coffers from businesses during 2010-19 as a result of LIFO repeal, according to administration estimates.

Many oil and gas companies use LIFO. Like LIFO companies in other industries, they'd face jumps in current and possibly future tax liabilities if the method, in use since the 1930s, were repealed.

A group called the LIFO Coalition has been fighting repeal initiatives since 2006. Managed by the National Association of Wholesaler-Distributors (NAW), the coalition represents nearly 100 trade associations, other business groups, and corporations.

On June 30, NAW reported on visits by coalition representatives to key members of the Senate Finance and House Ways and Means Committees. In Congress, the issue has little to do with LIFO's supposed conceptual flaws.

"This is all about money, not LIFO," NAW told its members. Lawmakers "do not argue that LIFO should be repealed on its merits but only that they need more of your tax dollars."

While acknowledging LIFO as an appropriate accounting method, lawmakers nevertheless "were not responsive that LIFO should not be repealed absent an objection to it on the merits," NAW said.

The group added that lawmakers seemed interested only in "quantitative information" about the effects of repeal on specific businesses.

One other point in the NAW report should worry oil and gas companies: Among potential compromises suggested by the lawmakers was LIFO repeal for specific industries.

In the current political climate, oil and gas would not escape such targeted tax mistreatment.

NAW said business participants in the meetings rejected industry-specific LIFO repeal and other proposed compromises, including repeal limited to publicly held or large companies and repeal with no retrospective effect.

(Online July 3, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Unauthorized trades push price peaks

Front-month crude contracts jumped June 30 to "fake" intraday highs of $73.38/bbl on the New York Mercantile Exchange—the highest this year—and $73.50/bbl on the International Petroleum Exchange through unauthorized trades by an employee at a subsidiary of PVM Oil Associates Ltd., London. PVM subsequently announced a loss of almost $10 million.

The August contract for benchmark US light, sweet crudes traded through a $4.48/bbl high-low price difference June 30 before closing at $69.89/bbl, down $1.60 for the day on NYMEX. In London, the August IPE contract for North Sea Brent crude retreated $1.69 to $69.30/bbl that same day. Prices continued to drop during the next two sessions with the NYMEX and ICE contracts closing at $66.73/bbl and $66.65/bbl, respectively, on July 2.

"After the PVM high, it was a downhill race," said Olivier Jakob at Petromatrix, Zug, Switzerland, with the NYMEX crude contract losing $3.53/bbl during the week and closing $7.75/bbl lower than the June 30 high. "Brent lost $3.31/bbl during the week," said Jacob. Prices were still falling in early trading July 6, as the New York market resumed business after the 3-day US Independence Day holiday, July 3-5. In Houston, analysts at Raymond James & Associates Inc. said, "Crude oil is trading around a 5-week low as the US dollar strengthened and concerns of a prolonged global economic slowdown continue to impact sentiment."

At KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, analysts asked, ""How can a trader enter into futures contracts representing 18 million bbl of oil at a time of day—early morning—when normally only 500,000 bbl are traded, without anybody thinking something was strange? Where were the ICE monitors and the Financial Services [Authority that regulates most aspects of UK financial dealing]?" Concerning the usefulness of those market regulators, KBC analysts said, "Their resemblance to a chocolate teapot is striking."

'A massive weapon'

On the other hand, with yet another rogue trader involved in unauthorized speculation that drove up crude prices on the futures markets, KBC analysts said, "A massive weapon has been handed to supporters of tighter regulation of futures markets, not just affecting oil but for other commodities, which are literally the raw material of economic prosperity." They warned, "We haven't heard the end of this."

Jakob said, "The PVM trades had a relatively small impact by themselves but a greater subsequent impact on the chart formations. It is counterintuitive, but the net impact of the PVM fat fingers had a net negative impact (buying to a recent high, then selling and letting the world know the buying was fake) on the technical picture." He said, "Technically, West Texas Intermediate took a beating" in the short trading week of June 29-July 2.

KBC analysts said, "With economic news still gloomy, oil demand sluggish, stocks plentiful, and no supply-side disruption in sight, we could be on the verge of a short term downward price correction." They said, "There is a growing perception that although recovery will come, it will not be tomorrow."

Bullish traders need a support level of $66/bbl "to keep some control of the game Jakob said, but WTI dropped through that price level in "thin electronic trades" on July 3. He said, "WTI is now below the lower Bollinger [a band plotted two standard deviations away from a simple moving average], which could bring some support; but if another set of lower highs and lower lows are printed, it will need to look for the 50-day moving average as the next level of support around $63.70/bbl."

He said July 6, "If $66/bbl can be [maintained] early in the week on the back of the new pipeline bombings in Nigeria, WTI will still face some strong resistance between $70-73/bbl. Hence on any early recovery, we would not expect very much apart from a consolidating range between $66-70/bbl. Last year the peaks were reached in the first half of July, and this might prompt some expectations that a similar seasonal pattern is occurring this year."

Meanwhile, in Nigeria a presidential offer of amnesty had encouraged some hope that passions might cool in the Niger Delta. But attacks on oil installations by hardcore militants "have continued rather than stopped," said Jakob. "Over the weekend [July 4-5] a Royal Dutch Shell PLC installation in the Eastern Delta (Bonny) was attacked and overnight a Chevron Corp. installation as well. The production levels in Nigeria are falling to multiyear lows and getting closer to the day when only [offshore floating production, storage, and offloading vessels] FPSOs are left running," he said.

(Online July 6, 2009; author's e-mail: samf@ogjonline.com)

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Abstracts are due by October 16, 2009.

Please submit a 150-400 word abstract by October 16, 2009.

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For more information, contact:

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Step-by-Step Guide for Developing and Submitting an Abstract:

Step 1: Choose an issue/technology/project that is relevant and informative to the oil sands and heavy oil industry, either from the list of suggestions on page 4, or propose your own industry-related topic.

Step 2: Choose the presentation method – Paper Presentation or Panel Discussion

Paper Presentation Guidelines

- Estimated presentation length – 20 minutes. A 10–minute discussion will follow each presentation.
- Submission of a manuscript to conference management is required in advance of Oil Sands and Heavy Oil Technologies to enable publication of the conference proceedings. Copyright of papers and presentations belongs to Oil Sands and Heavy Oil Technologies Conference & Exhibition.
- Maximum length of paper should be 15 typewritten pages, including references. Bibliography tables should not exceed six pages.
- Full instructions on preparation of manuscripts and presentations will be sent to authors of selected papers. Complete manuscripts must be provided by **May 2010**.
- Complimentary Registration - One presenter per selected presentation is eligible for complimentary 'Full Delegate' registration to Oil Sands and Heavy Oil Technologies, which includes admission to the exhibit hall and conference, two delegate luncheons, exhibit hall floor reception.

Panel Discussion Guidelines

- Panel submissions must contain content for a complete 90 minute panel discussion, including confirmed panelists.
- Panel sessions are a less structured environment and allow conference attendees to interact with the panelists.
- Panelists are not required to submit a manuscript, but each panelist is encouraged to deliver a short 10-15 minute presentation.
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Step 3: Develop a well-written, concise synopsis of your proposed presentation topic that addresses all key points of issue/project technology, approximately 150-400 words in length.

Step 4: **ONLINE SUBMISSION:** Abstracts are now submitted online at **www.oilsandstechnologies.com** - click on Online Abstract Submittal Form on the left-hand navigational bar menu.

Please fill out ALL appropriate fields; abstract submission process will not be completed without including all required information.

- State whether the topic has been previously presented and if so, when and at what conference.
- Indicate what topic categories the topic would best be suited.
- Include complete name, title, company, address, telephone, fax and e-mail for all authors or panelists, as necessary.
- Identify the presenter of record for manuscript presentations.

Once the abstract has been submitted, an automatic e-mail response will be sent to confirm Oil Sands and Heavy Oil Technologies conference management has received it. Please print this as well as retain the e-mail for your records.

If you do not have access to the Internet, abstracts can be submitted by mail on a CD-ROM (PC compatible) to:

Gail Killough
Oil Sands and Heavy Oil Technologies Conference Manager
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- Engineering Design
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- Economic Benefits of Cogeneration
- Sizing Cogeneration Facilities
- Cogeneration vs. Stand-Alone Electricity and Steam Production
- Transmissions Issues/Initiatives
- Remedial Action Scheme (RAS)
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- Byproduct Management
- Construction Optimization
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- Upgrading

Selection, Notification & Responsibilities

Selection Process: The Oil Sands and Heavy Oil Technologies 2009 Program Committee is composed of executives and engineers from all sectors of the oil sands and heavy oil industry. This committee will carefully review all abstracts submitted forming a highly educational and informative conference that addresses topical and timely oil sands industry issues.

All abstracts will be evaluated on the strength of the abstract submitted, including content matter, market trend and relevance of the material. Consultants and manufacturers may submit abstracts of a non-commercial nature, but all blatant commercial sales pitches will not be accepted for presentation.

Notification: All primary contacts will be notified in writing no later than **January 2010** as to whether or not their proposed Oil Sands and Heavy Oil Technologies abstract has been selected.

Primary Contact Responsibilities: The primary contact will be responsible for meeting all deadlines and requirements regarding the paper presentation or panel participation. The primary contact must sign a Materials Release Form by **February 2010** and agree to submit a final manuscript to be included in the conference proceedings by **May 2010.** This contact also needs to notify conference management of any changes, additions or corrections in author, co-author or panelist names, paper titles or availability to present the submitted paper at the appointed date and time. Unless otherwise noted on the abstract, the presenter will be considered the primary contact.

Speaker Registration: One presenter per paper accepted or up to five panelists per panel session will receive complimentary 'Full Delegate' conference registration which includes entrance to the conference and exhibit hall, delegate lunches, exhibit hall reception. All travel and hotel arrangements are the sole responsibility of the speaker.

Co-presenters are encouraged to attend Oil Sands and Heavy Oil Technologies, and we will gladly include their names in the conference program. However, they will be responsible for their own conference registration, hotel accommodations and other conference-related expenses.