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Major Upstream Projects

OPEC: Uncertainty fogs world oil outlook
Gas-to-electricity options can provide deepwater flexibility
Method calculates streams in split-flow sweetening
Study examines Chinese SPR growth alternatives

OIL&GAS JOURNAL
July 23, 2007
Volume 105.28

Major Upstream Projects

Regular Features

Cover

The Heerema Thialf deepwater construction vessel recently installed the topsides onto the single-column Atlantia SeaStar tension-leg platform that will serve as the production facility for the BHP Billiton Petroleum Inc.-operated Neptune field in the Gulf of Mexico. Neptune is one of the projects listed in the special report, p. 43, that tabulates major worldwide oil and gas ventures that will come onstream in the next few years. BHP Billiton expects the Neptune TLP, moored in 4,250 ft of water, to start processing production from subsea completed wells by yearend. The facility is designed to process up to 50,000 bo/d and 50 MMcfd of gas. Photo from BHP Billiton.


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General Interest — *Quick Takes*

House GOP panel members press for bill markup

Republicans on the US House Science and Technology Committee continue to press for a markup of HR 2337, which was originally scheduled for July 11 but was abruptly postponed by Chairman Bart Gordon (D-Tenn.).

Gordon began the markup and then quickly recessed it to negotiate with the House Natural Resources Committee, which passed the bill on June 13.

The measure would repeal several provisions in the 2005 Energy Policy Act, introduce new produced water disposal regulations, limit royalty in-kind payments to oil for refilling the Strategic Petroleum Reserve, require the US Minerals Management Service to conduct at least 550 annual audits by 2009, significantly increase surface landholders' rights in federal split-estate situations, and raise onshore oil and gas reclamation fees and bonds.

On July 12 Gordon said he would negotiate with the Natural Resources Committee to avoid forcing House parliamentarians to make a ruling on the Science and Technology Committee's jurisdiction. Republicans on his committee urged him to go before the parliamentarians because the bill contains at least seven sections that fall under that jurisdiction.

A spokesman for the committee's Republicans told OGJ on July 16 that they also would like a markup so they can introduce amendments to HR 2337, but they currently don't expect one.

Roan Plateau drilling opponents blocked

An amendment intended to prevent leasing on the Roan Plateau in Colorado was itself blocked for procedural reasons, but its proponents said they will continue efforts to prevent leasing on federal land within the Piceance basin. US Reps. John Salazar and Mark Udall, both Democrats from Colorado, had sought to amend the US Department of the Interior appropriations bill. DOI oversees the Bureau of Land Management, which would lease the area.

The amendment sought to stop funding for BLM leasing in that western Colorado area (OGJ, June 25, 2007, p. 30).

Questions were raised about financial estimates regarding potential Roan Plateau leasing revenues, and the amendment was blocked from being attached to the 2008 DOI Appropriations bill that passed the House floor on June 27.

"In effect, the [George W.] Bush administration is using exaggerated estimates of uncertain oil and gas revenue as an excuse to force additional oil and gas drilling on the West," Salazar said in a news release issued by his Washington, DC, office.

"Serious questions remain about the federal plan to open up more of the Roan to oil and gas drilling," Salazar said. "Had we been able to get a vote on our amendment, we are confident that we would have prevailed. We would have been successful in spite of the misinformation put out by proponents of drilling."

BLM authorized the drilling of as many as 1,570 gas wells over 20 years on part of the Roan Plateau in western Colorado. BLM indicated it probably will be at least 6 months before any leases are offered (OGJ, June 18, 2007, p. 31).

The decision issued by the Glenwood Springs BLM field office covers 70% of the 73,602 acres of the Roan. A final decision on the remaining 30%, which includes scenic and environmentally sensitive areas, is expected later this year following conclusion of a public comment period.

Mexico beefs up security after pipeline bombings

Mexico has increased security measures at strategic installations in the country following a series of bombings on fuel pipelines operated by state-run Petroleos Mexicanos (Pemex).

The Interior Ministry condemned the rebel group Ejército Popular Revolucionario (EPR), which claimed responsibility for blasts on the pipelines in central Mexico July 5 and 10 and said the attacks were "the start of a national campaign of harassment against the oligarchy and this illegitimate government."

The group said it would continue the "harassment" until Mexican President Felipe Calderon Hinojosa and Oaxaca governor Ulises Ruiz show that three EPR members, arrested in Oaxaca, are alive. According to reports, no one has seen EPR members Edmundo Reyes Amaya, Raymundo Rivera Bravo or Gabriel Alberto Cruz Sanchez since their arrest May 25.

The July 10 explosion forced suspension of service on the 36-in. pipeline that runs between Mexico City and Guadalajara, but caused no injuries or damage outside of the pipeline's installations, Pemex said.

The July 5 explosions at a Pemex pipeline in nearby Guanajuato state forced evacuations but caused no injuries.

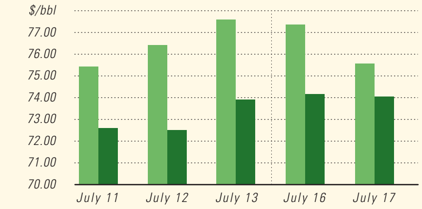
The Procuraduria General de la Republica said its forensic tests showed that the three bombs that exploded in Guanajuato were all of the same type and had exploded simultaneously.

As a result of the attacks—the first time EPR has hit Mexico's economic infrastructure—automakers Nissan and Honda halted production at plants in Aguascalientes and Guadalajara due to the lack of gas, and Mexican glass maker Vitro temporarily shut down two glass container plants at Queretaro and Guadalajara.

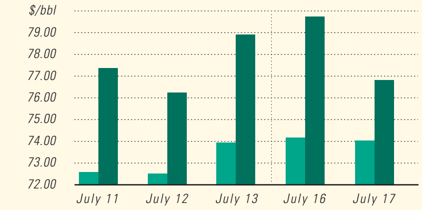
Pemex said July 10 that it expected to restore service on the Mexico City-Guadalajara pipeline in 3-4 days. ✦

Industry Scoreboard

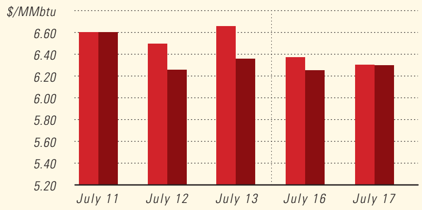
IPE BRENT / NYMEX LIGHT SWEET CRUDE



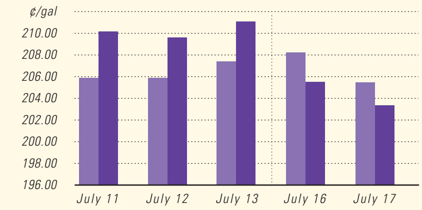
WTI CUSHING / BRENT SPOT



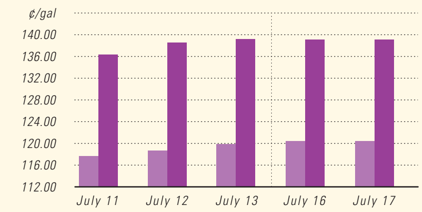
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



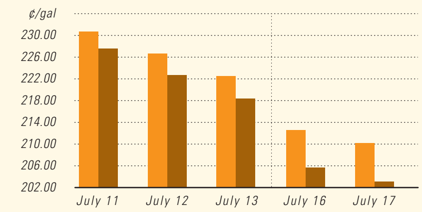
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

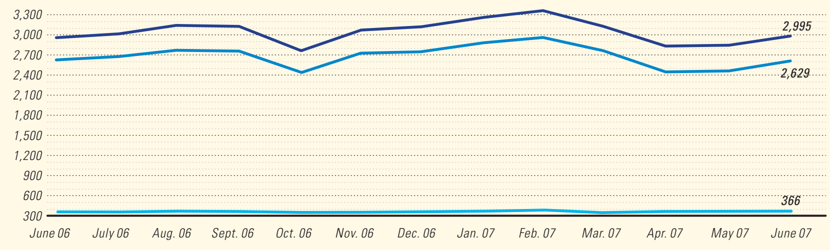
US INDUSTRY SCOREBOARD — 7/23

Latest week 7/6	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	9,663	9,557	1.1	9,233	9,113	1.3
Distillate	4,036	4,010	0.6	4,274	4,175	2.4
Jet fuel	1,672	1,646	1.6	1,631	1,607	1.5
Residual	748	682	9.7	783	723	8.3
Other products	4,950	4,721	4.9	4,851	4,817	0.7
TOTAL DEMAND	21,069	20,616	2.2	20,772	20,445	1.6
Supply, 1,000 b/d						
Crude production	5,198	5,122	1.5	5,175	5,085	1.8
NGL production[2]	2,396	2,396	—	2,338	2,148	8.8
Crude imports	10,025	10,778	–7.0	10,129	10,025	1.0
Product imports	3,994	3,761	6.2	3,587	3,558	0.8
Other supply[3]	1,013	977	3.7	915	1,106	–17.3
TOTAL SUPPLY	22,626	23,034	–1.8	22,144	21,922	1.0
Refining, 1,000 b/d						
Crude runs to stills	15,389	15,588	–1.3	15,112	15,138	–0.2
Input to crude stills	15,587	15,923	–2.1	15,380	15,486	–0.7
% utilization	89.3	91.5	—	88.2	89.1	—

Latest week 7/6	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	352,580	354,042	–1,462	335,316	17,264	5.1
Motor gasoline	205,576	204,433	1,143	212,651	–7,075	–3.3
Distillate	122,370	121,610	760	129,899	–7,529	–5.8
Jet fuel-kerosine	41,158	40,619	539	39,847	1,311	3.3
Residual	35,499	34,845	654	41,733	–6,234	–14.9
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	22.9	23.1	–0.9	21.1	8.5	
Motor gasoline	21.4	21.4	—	22.3	–4.0	
Distillate	29.6	29.4	0.7	31.7	–6.6	
Propane	50.5	45.2	11.7	63.5	–20.5	
Futures prices[5] **7/13**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	72.95	72.01	0.94	75.29	–2.34	–3.1
Natural gas, $/MMbtu	6.57	6.65	–0.07	5.90	0.67	11.4

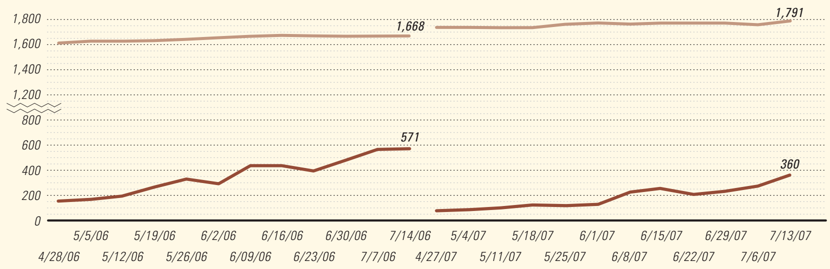
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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

Exploration & Development — *Quick Takes*

Total, Gazprom to develop for Shtokman field

Russia's OAO Gazprom and France's Total SA have signed a framework agreement for the joint development of the first phase of the giant Shtokman gas-condensate field in the central part of the Barents Sea off Russia.

Shtokman field reserves are estimated at 3.7 trillion cu m of gas and more than 31 million tons of condensate.

The companies will establish a special purpose vehicle to organize the design, financing, construction, and operation of the infrastructure of the delelopment's first phase, which will produce 23.7 billion cu m/year of gas. The SPV will own this infrastructure for 25 years from field commissioning.

Gazprom will hold a 75% participating interest in the vehicle and Total will have 25%. Upon completion of phase one operations, Total will transfer its share to Gazprom. The agreement also provides for the possibility for other foreign partners to join the project up to a 24% participating interest at the expense of Gazprom's share.

Deliveries of pipeline gas are expected to start in 2013. First LNG will be delivered in 2014.

PTTEP finds large gas deposit in Gulf of Martaban

Thailand's PTT Exploration & Production PLC discovered a large offshore natural gas deposit in Myanmar's Gulf of Martaban, according to state media.

The New Light of Myanmar newspaper said PTT discovered a deposit of gas estimated at 8 tcf. PTT confirmed the discovery but declined to comment on the specific amount of gas in the reserve.

The appraisal well, Zawtika-5, reached a TD of 2,527 m and encountered seven zones of gas-bearing formation with a total thickness of 100½ m. It was the eighth well (four exploration and four appraisal wells) drilled on that block, which lies 300 km south of Yangon (OGJ Online, June 25, 2007).

PTTEP Pres. Maroot Mrigadat said the field shows promising potential for further development, but added that a precise estimate of the reserves awaited additional exploration.

PTTEP plans to start production from the block, designated M-9, next April. The field will likely be one of Thailand's main sources of gas, Mrigadat said.

PTTEP signed a production-sharing contract with Myanmar for exploration and production of oil and gas from Block M-9 in November 2003.

OGDC taps gas, condensate in Pakistan well

Oil & Gas Development Co. Ltd. (OGDC) has made a natural gas and condensate discovery with its Chandio-No. 1 well on Tando Allah Yar block in the Hyderabad district of Pakistan's Sindh province. The exploration effort is a joint venture of operator OGDC, with 95%, and Government Holdings (Pvt.) Ltd. (GHP) 5%.

Chandio No. 1, which was drilled to 3,660 m TD, targeted the Massive, Basal, and A-Sands Cretaceous Age Lower Goru formation. Based on drilling and electric log data, four zones were selected for testing, and hydrocarbons were found in Zone-3 (Massive-Sands) of the Lower Goru formation.

Initial short-duration testing produced 2.45 MMscfd of gas and 70 b/d of condensate at a wellhead flowing pressure of 540 psi through a 32⁄64-in. choke.

Separately, Pakistan has granted an offshore exploration license to GHP and has executed a production-sharing agreement with GHP and OGDC for Block No. 2366-6 (Eastern Offshore Indus-A) in the Arabian Sea.

The block covers 2,500 sq km. OGDC said it will invest $2.75 million during the first 2 years of the license's initial term.

Sudan awards Red Sea PSC to China's CNPC

China National Petroleum Corp. has signed a production-sharing contract with Sudan for exploration areas off northern Sudan.

Under the 20-year contract, CNPC will have exploration rights to Block 13 with an area of about 3.8 million sq km in shallow water on the Red Sea. The exploration period is 6 years.

CNPC will conduct exploration jointly with Sudan's state-run Sudapet Ltd. and Indonesia's state oil and gas company PT Pertamina. ✦

Drilling & Production — *Quick Takes*

US drilling activity sets 21-year high

US drilling activity hit a new 21-year high, up 39 rotary rigs with 1,791 now working, Baker Hughes Inc. said July 13.

That surpasses the previous record of 1,775 set 2 weeks ago and is up from 1,668 units drilling during this same period a year ago.

All of the gain was on the land side, with a jump of 42 rigs to 1,693 active. Inland waters activity was unchanged at 22 rigs drilling. Offshore operations dropped 3 rotary rigs to 75 in the Gulf of Mexico and 76 in federal waters as a whole.

Texas' rig count jumped by 12 to 837 this week despite recent rains that caused flooding in some parts of the state. Colorado increased by 4 to 112, and California was up 3 to 38. Louisiana added 1 for a total of 182 rotary rigs working.

Oklahoma, which also had heavy rains, was down 5 rigs to 186 drilling. New Mexico and Wyoming dropped 2 rigs each to respective counts of 85 and 69. Alaska was down 1 to 8.

Canada's weekly rig count shot up by 74 to 360 units working. That's down from 571 during the same period last year, however.

Cavendish gas field production starts off the UK

RWE Dea UK Development Ltd. has begun commercial gas production of 60 MMcfd from one well in Cavendish gas field on Block 43/19a in the UK Southern Gas basin. The field lies in 18.5 m of water.

Field operator RWE Dea and equal partner Dana Petroleum PLC

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

are drilling second and third wells that are expected to come on stream before yearend. Cavendish, a Carboniferous gas field discovered in 1989, is RWE Dea's first operated development project in the UK.

The development consists of a 6-slot, minimum-facilities fixed platform tied back to the Murdoch platform via 47 km of newly laid pipeline. Murdoch is part of the Caister Murdoch system operated by ConocoPhillips, which transports the gas onward to the Theddlethorpe gas terminal in the UK.

Cavendish field production originally was expected to start in the first quarter with an initial flow of 100 MMcfd and to continue until 2016 (OGJ Online, Nov. 26, 2006).

India proclaims first coalbed methane sale

London concern Great Eastern Energy Corp. said it has made India's first sale of coalbed methane as compressed natural gas for vehicles in Asansol, West Bengal, 125 miles northwest of Calcutta.

The company said it is receiving $13-15/Mcf for the gas.

Great Eastern has drilled 23 production wells and plans to drill 80 more in phases over 3 years. It holds a CBM license on 210 sq km in the Raniganj coal field in West Bengal, where consulting engineers estimated original gas in place at 1.92 tcf (see map, OGJ, Dec. 13, 2004, p. 35).

Chevron to replace Tahiti spar's mooring shackles

Chevron Corp. said it is pursuing "alternate actions" to ensure new shackles are available "in the shortest time-frame possible" for its Tahiti project in deepwater Gulf of Mexico, after a second round of tests identified a metallurgical problem with the facility's existing mooring shackles.

Several scenarios are being considered, but Chevron does not yet have an "absolute clear picture" as to when the project will be operational, a company spokesman said. The $3.5 billion project 190 miles south of New Orleans was scheduled for completion in mid-2008.

Major components of the project are nearing completion, and installation work is expected to continue once timing for the new shackles is determined.

The company also has initiated an investigation to uncover why initial tests failed to identify the problems with the shackles, the spokesman said.

Additional tests were conducted after Chevron's contractor discovered a metallurgical problem with shackles on a similar installation for another company. Metallurgical problems were subsequently discovered in the Tahiti shackles as well.

Chevron says the spar's integrity is not impacted by the problem with the mooring shackles, as they are not part of the spar hull. ✦

Processing — *Quick Takes*

Total to build two units at Lindsey refinery

Total SA has begun construction of a hydrodesulfurization unit and a hydrogen production unit at its 221,286 b/cd Lindsey refinery, near Immingham in the UK.

The HDS unit will have a 1 million tonne/year capacity. The hydrogen production unit—more specifically a steam methane reformer—is key to the desulfurization process.

The two units together represent a €300 million investment. Commissioning is scheduled for 2009, Total said.

The units will increase Total's production of ultralow-sulfur diesel and will increase the refinery's capacity to process less-expensive sour crudes.

Faster work urged on Vietnamese projects

Vietnamese Prime Minister Nguyen Tan Dung has asked contractors to speed up construction of several oil and gas projects, including the Dung Quat refinery, the Nghi Son refinery and petrochemical complex, and the Ca Mau combined-cycle project.

Regarding the 140,000 b/d Dung Quat refinery in the central coastal province of Quang Ngai, Nguyen instructed state-owned PetroVietnam to work with Technip to address problems that he said have caused delays (OGJ Online, Feb. 19, 2007).

Nguyen wants the refinery to become operational by February 2009.

The $2.5-billion refinery is being built in the Dung Quat Economic Zone in Binh Son district's Binh Tri and Binh Thuan communes.

Construction of the refinery began in June 2005, 7 years after the target date stipulated by a 1997 National Assembly resolution.

Meanwhile, the Nghi Son refinery and petrochemical project is being built on 325 hectares in the Tinh Gia district of Thanh Hoa province, with completion set for 2011.

The project includes a 140,000-b/d refinery, a 150,000-350,000-tonne/year polypropylene plant, and a 260,000-tonne/year polyester fiber plant.

Construction of the Ca Mau combined-cycle project in U Minh district, 15 km from Ca Mau City, started in March 2001. PetroVietnam said the complex will include a gas pipeline, a power plant, and a nitrogen fertilizer plant.

Siemens planned to deliver two 250-Mw gas-fired turbines and generators to the Ca Mau project last August and to start them by March.

Nguyen specifically requested a speed-up of installation of heat-control units on the 332-km PM3-Ca Mau pipeline, which is to carry 2 billion cu m/year of gas from offshore fields to the complex.

Interest in a Central America refinery progresses

Mexico's Ministry of Energy said four international companies have expressed interest in constructing a refinery in Central America under terms of the Mezo-American Energy Integration Program (PIEM).

The ministry named the companies as Colombia's state-owned oil company Ecopetrol; Itochu Corp. of Japan, Reliance Industries Ltd. of India; and US company Valero Energy Corp.—all four of which have been preselected by PIEM.

Benefits offered by the bidding include an 8-year buy-sale contract of Mexican oil, plus bank credits from Inter-American Development Bank and Central American Economic Integration Bank.

Costa Rica, Guatemala, Honduras, and Panama have ratified the PIEM, which will allow the investor to build a refinery in their countries.

PIEM, which first met in December 2005, aims to complete four tasks: to build a refinery in a Central American nation, create a "spine" of electricity links among the PIEM nations, harmonize energy regulation across the region, and promote the use of sustainable and renewable energy.

PIEM nations include Belize, Colombia, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua, Panama, and the Dominican Republic.

Coffeyville Resources restarts flooded plant

Coffeyville Resources LLC has restarted its fertilizer plant after record flooding on the Verdigris River caused both the Coffeyville, Kan., nitrogen fertilizer plant and a nearby refinery to be shut down and evacuated in early July.

Both facilities are owned by subsidiaries of Coffeyville Resources. The fertilizer plant is on higher ground and sustained less damage than the refinery, which remains down pending repairs (OGJ, July 16, 2007, Newsletter).

Coffeyville Resources Refining & Marketing LLC said its 100,000 b/cd refinery is expected to resume operations by mid-September. Nearly 1,000 contract workers are helping repair and replace flood-damaged equipment.

Kevan A. Vick, executive vice-president and general manager for Coffeyville Resources Nitrogen Fertilizer, said bringing the fertilizer plant back on line involved replacing or repairing 30% of all electric drives and repairing 60% of the motor control centers.

The fertilizer plant delivers its products to customers primarily in Missouri, Kansas, Texas, Nebraska, and Iowa. The plant uses petroleum coke as the primary feedstock to produce nitrogen fertilizers. In 2006, it produced 369,300 short tons of ammonia of which 66% was upgraded to 633,100 short tons of urea ammonium nitrate. ✦

Transportation — *Quick Takes*

BP takes delivery of 'world's largest' LNG carrier

BP Shipping has taken delivery in early July of the British Emerald LNG carrier, which the company called the "world's largest" with a capacity of 155,000 cu m. The vessel has an overall length of 288 m and a width of 44.2 m.

British Emerald is powered by four diesel-electric engines and is equipped with a bow thruster to assist in mooring operations. It's the first in a series of four diesel-electric gas ships.

Built by Hyundai Heavy Industries in South Korea, the vessel was designed for reduced fuel costs and greenhouse gas emissions compared with conventional LNG carriers. The dual-fuel technology allows the diesel engines to run on "boil-off" gases from the cargo tanks or on conventional diesel fuel.

The 23-man crew will put the vessel through an extensive commissioning program that is scheduled to take 10 days.

This vessel is the first of a fleet of four Gem class LNG carriers. The British Diamond, British Ruby, and British Sapphire are scheduled to be delivered in 2008.

Shell to buy Qatargas 4 output

A Royal Dutch Shell PLC affiliate signed an agreement with Qatar Liquefied Gas Co. Ltd. (4) in Doha to buy effectively the entire output—7.8 million tonnes/year—of LNG from the Qatargas 4 project.

Shell will send the LNG to its Elba regasification terminal for eastern US markets. Elba is being expanded to process 2.1 bcfd of gas by mid-2010 under an $850 million investment plan.

The sales contract underpins the development of Qatargas 4 which brings Qatar closer to its 77 million tonne/year target of becoming the world's leader in LNG production.

First LNG cargoes from Qatargas 4 are expected at the end of the decade, and the liquefaction complex will produce 1.4 bcfd of gas, including an average 24,000 b/d of LPG and 46,000 b/d of condensate from Qatar's North Field over the 25-year life of the project. The main engineering, procurement, and construction contract for onshore facilities was awarded in December 2005 and construction activities are progressing in Ras Laffan.

Linda Cook, Shell's executive director of gas and power, said the integrated project "is another clear illustration of our 'more upstream, profitable downstream' strategy in action." This is the seventh LNG project in which Shell has an equity stake.

Qatar Petroleum (QP) and Shell incorporated Qatargas 4 as a joint venture between an affiliate of QP (70%) and an affiliate of Shell (30%). The JV will own the Qatargas 4 project's onshore and offshore assets.

Trans-Afghan gas pipeline back in play

Turkmenistan and Afghanistan have agreed to cooperate on several energy-related projects, including revival of the long-mooted Trans-Afghan natural gas pipeline.

The two sides signed several agreements following talks between Turkmen President Gurbanguly Berdymukhammedov and Afghan President Hamid Karzai, who visited Turkmenistan July 5-6.

Berdymukhammedov said his country remains interested in the $2 billion project to build a gas line more than 1,460 km across Afghanistan to Pakistan and then to India. He said Turkmenistan would be ready to send 30 billion cu m/year of gas through the line.

The original plan was to deliver gas from Turkmenistan's Dauletabad field to Kandahar, Afghanistan; Multan in central Pakistan, and onward to India (OGJ Oct. 28, 2002, p. 47).

The two leaders also agreed to construct additional electric power lines and related infrastructure in Afghanistan. ✦

Correction

In an article entitled, CSB blames unsafe work practices for oil field blast, the total number of employees killed should have been reported as three (OGJ, June 18, 2007, p. 31).

Letters

Land of misinformation

I found National Aeronautics and Space Administration Administrator Michael Griffin's responses absolutely on the mark (OGJ, June 11, 2007, p. 76). No one denies the world is heating up. It has been since the mini-ice age of the 1400-1500 time period. I believe it is part of natural cycles, and in a few years temperatures will make their cyclical turn downward. In about 2040-50, these same alarmists will make the claim we are entering an ice age (as in 1973). The ironic thing is that the alarmists today will take credit for it and will probably advocate releasing greenhouse gases to reverse the trends. If our weather forecasting were nearly as good as the modeling 100 years from now, we actually could plan outdoor events.

As for ethanol, it's interesting but very predictable that some of the air quality data is coming in, and much to the surprise of everyone the air quality is NOT improving but getting worse. Gasoline performance is in the decline as the poor gas mileage data trickles in. It's a terrible scamming of America, the corn lobby and Archer Daniels Midland have done. The funny thing will be is that in about 5-10 years, the truth will be known and all those corn-balls will blame the oil companies.

We are pilgrims in a land of misinformation. I appreciate your efforts in informing the masses or at least those who read Oil & Gas Journal.

John Wakefield
Houston, Tex.

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.

2007

JULY

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

IADC Well Control of the Americas Conference &

Calendar

Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

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

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

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

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

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

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

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

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

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

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

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

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

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

EXPOGAZ Gas Congress, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 11-13.

European Gas Forum, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 12-13.

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

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 2-6.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail:

Calendar

pmirkin@gasprocessors.com, website: www.gasprocessors.com. 3.

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

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

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

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

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

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

International Bottom of the Barrel Technology Conference & Exhibition, Athens, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 11-12.

The Athens Summit on Global Climate and Energy Security, Athens, +30 210 688 9130, +30 210 684 4777 (fax), e-mail: jangelus@acnc.gr, website: www.athens-summit.com. 14-16.

ERTC Petrochemical Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 15-17.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 15-19.

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 16.

Global E&P Technology Summit, Barcelona, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.eptsummit.com. 16-17.

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

PIRA New York Annual Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 18-19.

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 22-24.

SPE/IADC Middle East Drilling and Technology Conference, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 22-24.

World Energy & Chemical Exhibition and Conference, Kuwait City, +32 2 474 8264, +32 2 474 8397 (fax), e-mail: d.boon@bruexpo.be, website: www.www.wecec-kuwait.com. 22-25.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), website: www.lagcoe.com. 23-25.

Pipeline Simulation Interest Group Annual Meeting, Calgary, Alta, (713) 420-5938, (713) 420-5957 (fax), e-mail: info@psig.org, website: www.psig.org. 24-26.

GSA Annual Meeting, Denver, (303) 357-1000, (303) 357-1070 (fax), e-mail: gsaservice@geosociety.org, website: www.geosociety.org. 28-31.

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. Oct. 30-Nov. 1.

Chem Show, New York City, (203) 221-9232, ext. 14, (203) 221-9260 (fax), e-mail: mstevens@iecshows.com, website: www.chemshow.com. Oct. 30-Nov. 1.

Methane to Markets Partnership Expo, Beijing, (202) 343-9683, e-mail: asg@methanetomarkets.org, website: www.methanetomarkets.org/expo. Oct. 30-Nov. 1.

NOVEMBER

IADC Annual Meeting, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 1-2.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 6-8.

✦GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8.

IPAA Annual Meeting, San Antonio, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

SPE Annual Technical Conference and Exhibition, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-14.

World Energy Congress, Rome, +39 06 8091051, +39 06 80910533 (fax), e-mail: info@micromegas.it, website: www.micromegas.it. 11-15.

API/NPRA Fall Operating Practices Symposium, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 13.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 13-15.

Australian Society of Exploration Geophysicists International Geophysical Conference & Exhibition, Perth, (08) 9427 0838, (08) 9427 0839 (fax), e-mail: secretary@aseg.org.au, website: www.aseg.org.au. 18-22.

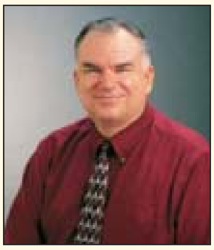
ERTC Annual Meeting, Barcelona, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 19-21.

✦Asia Pacific Natural Gas Vehicle Conference & Exhibition, Bangkok, +66 0 2617 1475, +66 0 2271 3223 (fax), e-mail: angva@besallworld.com, website: www.angvaevents.com. 27-29.

IADC International Well Control Conference & Exhibition, Singapore, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.


Natural Expansion
It's only natural that Falcon has leveraged its expertise in natural gas storage to expand into a full-service midstream energy company. We have built an integrated asset portfolio that includes high-deliverability, multi-cycle gas storage, crude oil production and NGLs extraction, gas processing and gas pipeline facilities. With assets strategically located across the U.S. natural gas pipeline grid, we're a significant force from coast to coast, uniquely positioned to extract value from the midstream energy segment in North America.

The strategic Strait of Hormuz



Alan Petzet
Chief Editor-Exploration

The Strait of Hormuz is the world's premier oil transportation choke point, and it seems worthwhile from time to time to recite the details that make it so strategic.

Energy markets took a deep breath in June when Cyclone Gonu passed over the area with little disruption, but it is political—not natural—forces that give the strait its importance.

So, with help from US Energy Information Administration researchers, here goes.

The Strait of Hormuz is a body of water 600 miles long that provides the only water outlet for the Persian Gulf. The strait lies between Iran and Oman and several of the United Arab Emirates. Hormuz's length includes the Gulf of Oman, which connects the strait with the Arabian Sea.

The strait is 34 miles wide at its narrowest point. It consists of two 2-mile channels for inbound and outbound tankers separated by a 2-mile buffer zone.

The Persian Gulf countries of Saudi Arabia, Iran, Iraq, Kuwait, Qatar, the UAE, and Bahrain exported 18.2 million b/d in 2006, including 17 million b/d via the strait. This represents one fifth of global oil supply.

OGJ figures show these countries with 728 billion bbl or 55% of world proved reserves.

More than 3.5 bcfd of natural gas transits the strait on LNG tankers enroute to Asia, Europe, and North America.

Gross oil imports to Organization of Economic Cooperation and Development nations from Persian Gulf countries averaged 10.4 million b/d or 31% of OECD imports in 2006, and US gross oil imports from the Persian Gulf were 2.2 million b/d or 17% of US imports in 2006.

The rest of the Persian Gulf exports went by pipeline through Turkey to the Mediterranean and via Saudi Arabia to the Red Sea.

Alternate routes

Several Middle Eastern oil-producing countries have built pipelines in the past along routes that avoid the Strait of Hormuz, but most of these are in disuse due to geopolitical or economic issues.

The 745-mile, 5 million b/d East-West Pipeline traverses Saudi Arabia from Abqaiq on the Persian Gulf to Yanbu on the Red Sea. It is used at less than half capacity.

The 290,000 b/d Abqaiq-Yanbu natural gas liquids pipeline, parallel to the East-West crude line, is due for upgrades to 555,000 b/d in 2008. It serves Yanbu's petrochemical plants.

The Trans-Arabian Pipeline, or Tapline, from Qaisumah, Saudi Arabia, to Sidon, Lebanon, was mothballed in 1984 due to turmoil in Lebanon and economic reasons. Its operating capacity is believed to be 50,000 b/d against a design capacity of 500,000 b/d.

The Iraqi Pipeline through Saudi Arabia, or IPSA, extends from southern Iraq through Saudi Arabia and parallels the East-West Pipeline to the Red Sea north of Yanbu. It was closed in August 1990 after Iraq invaded Kuwait. Saudi Arabia expropriated it in June 2001 and converted it to transport gas to Yanbu, but it could be used to move 1.65 million b/d of oil.

Iraq built the twin bidirectional Strategic Pipeline in 1975 to allow shipment of Rumaila crude through Turkey and Kirkuk crude via the Persian Gulf. Work on the second pipeline ceased during the 1990-91 Gulf War. The first pipeline needs rehabilitation.

The dual 600-mile Iraq-Turkey pipeline from Kirkuk to Ceyhan, Turkey, has operated sporadically for years. Capacities are 1.1 million b/d and 500,000 b/d, but major repairs and upgrades are needed.

The twin Iraq-Syria-Lebanon Pipeline (ISLP) from Kirkuk to Banias, Syria, hasn't been used since 2003. Iraq used it to ship 200,000 b/d from southern Iraq to Syrian refineries in 2001-03. Combined capacity is 700,000 b/d.

The future

EIA projects Persian Gulf oil production to grow moderately from 23 million b/d in 2006, reaching 26 million b/d by 2015, nearly 30 million b/d by 2020, and more than 38 million b/d by 2030.

This could increase the share of Persian Gulf oil production to 33% of the world total by 2030, up from 28% in 2006.

Meanwhile, another pipeline is proposed to bypass the strait on the south.

China National Petroleum Corp. said Abu Dhabi International Investment Co. awarded a contract to CNPC's two pipeline E&C units to jointly build a 360-km, 48-in., 1.5 million b/d pipeline from Habshan onshore oil field in Abu Dhabi to an export terminal in Fujairah on the Gulf of Oman, bypassing the Strait of Hormuz. One third of the oil would be processed in a refinery to be built in Fujairah (OGJ Online, June 4, 2007).

Starting and completion dates were not given for the pipeline, which would carry about 55% of UAE production. ✦

Second of three parts

More facts on antitrust

Two former officials of the US Federal Trade Commission are trying to correct antitrust misperceptions about the oil and gas industry. Last week, this space summarized the first four points presented in their monograph, "A Dozen Facts You Should Know about the Oil Industry" (OGJ, July 16, 2007, p. 17). Four more appear this week.

The officials are Timothy J. Muris, who served as chairman of the Federal Trade Commission in the George W. Bush administration, and Richard G. Parker, who was director of the FTC's Bureau of Competition in the Bill Clinton administration. They cochair the antitrust and competition practice in the Washington, DC, office of the O'Melveny & Myers LLP law firm, where Parker is a partner and Muris is of counsel.

Their facts presented here last week: 1. Economic learning and antitrust enforcement have evolved; we now know that big is no longer necessarily bad. 2. The antitrust authorities scrutinize the petroleum industry more closely than any other. 3. The American petroleum industry is not highly concentrated. 4. Refiners have expanded domestic and global capacity significantly.

The next four facts follow.

- *Fact 5: Refineries operate at or near their practical maximum utilization rates.*

Contrary to assertions that refiners limit operations to control supply and prices, US refineries ran at about 93% of capacity during 1994-2004, near maximum practical rates. Refiners have sustained high utilization rates while making modifications to comply with regulations, expanding capacity, and enduring disruptions.

- *Fact 6: Inventory practices have reduced costs and benefited consumers.*

At 2004 prices and volumes, inventory reductions between 1994 and 2004 reduced costs by about $1.9 billion/year, 33% of current inventory carrying and storage costs. Refiners achieved the savings without sacrificing reliability of supply.

In a 2006 report to Congress, the FTC rejected the assertion that oil companies had manipulated inventory levels to elevate prices during market disruptions. It said inventories declined because maintaining them is expensive and because reducing inventory costs is an important goal of modern manufacturing.

- *Fact 7: The profitability of the petroleum industry is commensurate with other industries over the long run.*

Between 1992 and 2006, the US oil industry invested more than $1.25 trillion in long-term energy initiatives, more than its net income of $900 billion. In 2006, new investment by the US oil industry exceeded $174 billion, and the industry plans $183 billion in new projects in 2007.

Between 1995 and 2005, the return on investment for refining was 10%, about 4.7% less than returns of the S&P Industrials. During 1977-2005, oil industry returns averaged less than 7%, compared with 9% for durable goods and more than 11.5% for the S&P Industrials. From 2002 to 2006, earnings per dollar of sales equaled 6.4¢ for all manufacturing industries and 7.4¢ for the oil industry. For 2006, all manufacturing industries averaged annual earnings of 8.2¢/$ of sales, while the oil industry averaged 9.5¢.

- *Fact 8: The FTC applies tougher standards to mergers in the oil industry than to mergers elsewhere.*

The agency applies the FTC-Department of Justice (DOJ) Horizontal Merger Guidelines more strictly to the oil industry than to others and requires divestitures in the petroleum industry at far lower levels of concentration.

More than 60% of petroleum merger enforcement takes place in markets involving five or more significant competitors, while substantially all merger enforcement in other industries occurs in markets with four or fewer competitors. Of all merger enforcement actions at concentrations below a Herfindahl-Hirshman Index (HHI) of 1,800, 97% involved the oil industry. The HHI, indicating concentration, can be as low as 0 (unconcentrated) or as high as 10,000 (monopolized). The oil industry accounted for 77% of merger enforcement actions at concentration levels below 2,400. Oil is the only industry in which the government undertakes significant enforcement actions at or below that level.

The average postmerger concentration level for mergers requiring divestitures is much higher in every other industry investigated by the government than for the petroleum industry. The FTC challenged 21 oil mergers during 1981-2007.

Next: Facts 9-12. ✦

OPEC: Uncertainty fogs world oil outlook

Judy R. Clark
Senior Associate Editor

Producers' current investment decisions may be clouded by such questions as the extent to which nonconventional fuels may be produced and used in the future and the effects those fuels may have on oil demand, said the Organization of Petroleum Exporting Countries in the group's 2007 World Oil Outlook.

OPEC's report, released June 26, contained what it called "inherent downside risks" to demand that included governmental, environmental, and conservation policies worldwide, questions about the long-term sustainability of biofuels production, and the possibility of slowing economic growth.

Although decisions and investment must be made now for future capacity expansions that require long lead-times for planning, design, and construction, some decisions may be problematic, especially for downstream expansions.

Security of demand is shown to be a real issue "intrinsically linked to the issue of security of supply."

The OPEC analysts said, "Without the confidence that demand for its oil will emerge, the incentive to undertake investment can be reduced, which, in turn, can exacerbate concerns over eventual sufficiency of capacity, and thereby hamper the drive towards long-term oil market stability.

"Alternatively, the emergence of large levels of unused capacity would lead to downward pressures upon oil prices, as it has in the past," they said, adding, "This would result in a huge loss of revenues, and OPEC member countries, as developing countries with keenly felt competing needs for financial resources, would be adversely affected in terms of available resources in such areas as education, healthcare, and infrastructure. Moreover, lower revenues would, in turn, negatively affect available resources for future investment, with further subsequent market instability—a distinct possibility."

The report looks at the supply-demand balance and attempts to determine the specific need for future investment in infrastructure and upstream-downstream capacity expansion to 2030.

In its analysis, which the analysts say is not a forecast, OPEC uses as its reference case an average global economic growth rate of 3.5%/year, on a purchasing power parity basis, and oil prices assumed to remain in the $50-60/bbl range for much of the period through 2030.

Demand to rise

World population is expected to grow by an average of 1%/year to 2030, reaching 8.2 billion, an increase of more than 1.7 billion from 2005. About 94% of this growth will come from developing countries, with North America the only OECD region set to experience any significant expansion, the report noted.

Energy demand will continue to increase for the foreseeable future, the analysts concluded, and oil will retain its leading role in meeting the world's growing energy needs (Table 1). Oil demand will rise to 118 million b/d by 2030 from the 2005 level of 83 million

WORLD ENERGY DEMAND, REFERENCE CASE

Table 1

	2005	2010	2020	2030	Growth, %/year, 2005-30	Fuels shares, % 2005	2010	2020	2030
	— Million tonnes of oil equivalent —								
Oil	4,002	4,319	4,996	5,689	1.4	39.2	38.4	37.5	36.5
Solids	2,822	3,144	3,703	4,181	1.6	27.6	28.0	27.8	26.8
Gas	2,346	2,655	3,352	4,276	2.4	23.0	23.6	25.1	27.4
Hydro-nuclear-renewables	1,041	1,117	1,283	1,434	1.3	10.2	9.9	9.6	9.2
Total	**10,212**	**11,236**	**13,335**	**15,580**	**1.7**	**100.0**	**100.0**	**100.0**	**100.0**

Source: Organization of Petroleum Exporting Countries b/d, OPEC estimates. This "assumes that no particular departure in trends for energy policies and technologies takes place."

Oil demand in Organization for Economic Cooperation and Development (OECD) countries, accounting for nearly 60% of total world oil demand, will reach 53 million b/d—a further growth of 4 million b/d—by 2030 (Table 2). Developing countries account for most of the rise in the reference case, with consumption doubling to 58.5 million b/d from 29 million b/d. Asian developing countries account for an increase of 20 million b/d, which represents more than two thirds of the growth in all developing countries.

Nevertheless, "energy poverty" will remain an important issue over this period, OPEC said. By 2030, developing countries will consume, on average, five times less oil per person than OECD countries.

Transportation will represent the main source of future oil demand increases; the global volume of commercial vehicles will more than double.

Growth in the OECD is expected to continue to increase, although saturation effects should increasingly have an impact upon the growth in passenger car ownership.

The potential for growth in the stock of cars, buses, and trucks, however, is far greater in developing countries. For example, two thirds of the world's population live in countries with fewer than 1 automobile/20 people. By 2030 the total stock of cars is expected to rise to 1.2 billion from 700 million in 2005.

After transportation, the main expected increase in oil use will be in the industrial and residential sectors of developing countries, which see a combined growth to 2030 of more than 11 million boe/d in the reference case. Household oil use is closely associated with the gradual switch away from traditional fuels, OPEC said—a trend expected to continue, especially in the poorer developing countries of Asia and Africa. Urbanization throughout the developing world is central to the shift towards commercial energy.

Although electricity production and consumption are expected to grow, "oil demand in this sector will experience no significant growth," the organization reports.

Sufficient supply

Resources are sufficient to meet future demand, OPEC says (Tables 2 & 3). The US Geological Survey estimates that reserves have doubled since the early 1980s, although cumulative production during this period was less than one third of that increase. Technology, successful exploration, and enhanced recovery from existing fields have enabled the increase, along with "a vast resource base of nonconventional oil to explore and develop."

Non-OPEC crude oil supply is expected to rise at first in the reference case to peak around 2015. Increases from Russia, the Caspian Sea area, and Brazil and other Latin America countries will compensate for decreases in the North Sea and elsewhere to maintain a plateau until 2020, when a gradual decline will begin, as nonconventional supplies continue to rise.

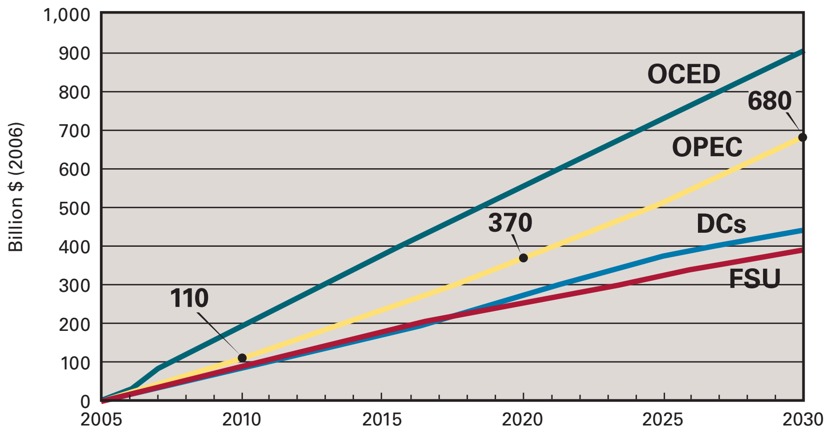
In the short term, the Middle East and Africa will experience a slight oil production increase to 2010, but they are expected to plateau at almost 5 million b/d.

Canadian oil sands will provide the most significant growth in nonconventional oil supply and biofuels from non-OPEC countries. It will rise in the reference case to 5 million b/d in 2030, from just 1 million b/d in 2005.

Coal-to-liquids and gas-to-liquids production also will increase—to 1.5 million b/d

CUMULATIVE UPSTREAM OIL INVESTMENT REQUIREMENTS, 2005-30

Fig. 1



Source: OPEC

WORLD OIL DEMAND OUTLOOK, REFERENCE CASE

Table 2

	2005	2010	2015	2020	2025	2030
	Million b/d					
North America	25.5	26.1	26.9	27.7	28.4	29.0
Western Europe	15.5	15.6	15.8	15.9	15.9	15.8
OECD[1] Pacific	8.6	8.6	8.6	8.6	8.6	8.5
Total OECD	**49.6**	**50.3**	**51.3**	**52.2**	**52.9**	**53.4**
Latin America	4.6	5.0	5.5	5.9	6.4	6.8
Middle East & Africa	3.0	3.4	4.0	4.6	5.2	5.9
South Asia	3.1	3.9	5.0	6.1	7.3	8.6
Southeast Asia	4.4	5.2	6.1	7.1	8.0	9.0
China	6.5	8.7	10.4	12.3	14.3	16.4
OPEC	7.4	8.2	9.1	9.9	10.8	11.7
Total DCs[2]	**29.0**	**34.5**	**40.0**	**45.9**	**52.0**	**58.5**
FSU[3]	3.8	4.0	4.2	4.3	4.5	4.6
Other Europe	0.9	0.9	1.0	1.0	1.0	1.1
Total transition economics	**4.7**	**4.9**	**5.2**	**5.4**	**5.5**	**5.7**
World	**83.3**	**89.7**	**96.5**	**103.5**	**110.4**	**117.6**

[1]Organization for Economic Cooperation and Development. [2]Developing countries. [3]Former Soviet Union.
Source: OPEC

and 500,000 b/d, respectively—in 2030 from about 150,000 b/d and less than 50,000 b/d in 2005. These increases will come primarily from the US, China, South Africa, and Australia, according to the report.

Biofuels supply impact

Although the use of biofuels is increasing in many regions of the world, unintended consequences from its production are beginning to appear, making a prognosis for its sustained use tenuous. "The potential growth for world biofuels must be balanced against the global impact of large-scale biomass use and trade for energy purposes in terms of land-use changes, competition with food supply and other biomass uses, biodiversity, and competition for water resources. In addition, the impact of the widespread use of biofuels on air quality in urban areas has not yet been fully assessed," OPEC said in the report.

Therefore, uncertainty is growing over the magnitude of the rise in non-OPEC nonconventional supply. For example, the European Union recently adopted a minimum binding target for biofuels to reach a 10% share in transport gasoline and diesel consumption. And in the US, the most recent White House proposal for reduction of US gasoline usage by 20% in the next 10 years—the "Twenty in Ten" goal—anticipates that alternative transport fuels production will reach more than 2 million b/d by 2017.

Such ambitious target pronouncements "amplify uncertainties for future demand and supply volumes," OPEC cautioned. "In total, the reference case sees more than 10 million b/d of nonconventional oil supply, including biofuels, coming from non-OPEC countries by 2030—8 million b/d more than in 2005."

Initial increases in both crude and noncrude supply will push total non-OPEC supply up to 54 million b/d in 2010—about 5 million b/d higher than in 2005. With demand rising by only a slightly higher rate, this leaves little room for additional OPEC oil. Indeed, with OPEC's noncrude supply, primarily natural gas liquids (NGL), set to rise to just under 6 million b/d by 2010, the demand for OPEC crude by 2010 is almost 1 million b/d below 2005 levels.

After 2010, non-OPEC crude supply, including NGL, is expected to stabilize, then eventually fall. Yet with nonconventional oil supply increasing at strong rates over the entire projection period, total non-OPEC supply actually continues to rise. The amount of oil supply expected from OPEC increases after 2010, rising, in the reference case, to 38 million b/d by 2020 and 49 million b/d by 2030.

WORLD OIL SUPPLY OUTLOOK, REFERENCE CASE

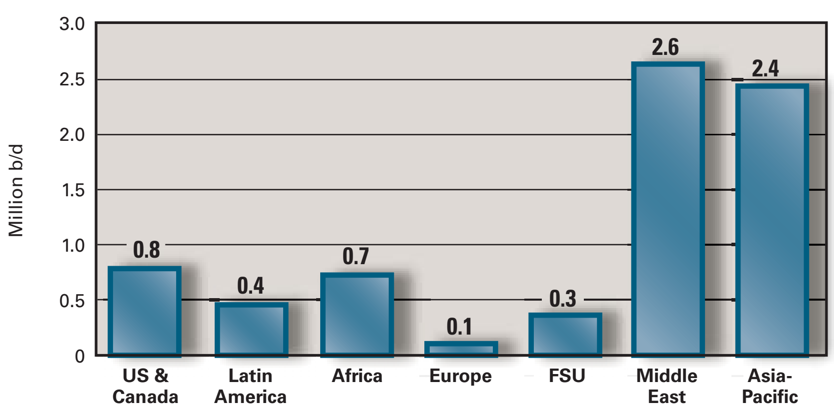
Table 3

	2005	2010	2015	2020	2025	2030
	Million b/d					
US & Canada	10.4	11.3	11.7	12.3	12.8	13.0
Mexico	3.8	3.8	3.8	3.5	3.2	2.9
Western Europe	5.8	5.0	4.3	3.9	3.5	3.2
OECD[1] Pacific	0.6	0.7	0.7	0.8	0.8	0.8
Total OECD	**20.5**	**20.9**	**20.6**	**20.5**	**20.3**	**19.9**
Latin America	4.3	5.0	5.6	6.2	6.6	6.6
Middle East & Africa	4.4	5.0	5.1	5.3	5.1	5.0
Asia	2.6	2.9	2.8	2.5	2.3	2.1
China	3.6	4.2	4.5	4.8	5.0	5.3
Total DCs,[2] excl. OPEC	**14.9**	**17.0**	**17.9**	**18.7**	**19.0**	**19.1**
Russia	9.4	10.3	11.0	11.2	11.2	11.2
Caspian and other FSU[3]	2.1	3.5	4.1	4.5	4.9	5.2
Other Europe	0.2	0.2	0.2	0.1	0.1	0.1
Total transition economics	**11.7**	**14.0**	**15.3**	**15.9**	**16.2**	**16.6**
Processing gains	1.9	2.2	2.4	2.8	3.0	3.2
Total non-OPEC + NGL	**49.0**	**54.1**	**56.3**	**57.8**	**58.5**	**58.8**
Of which: nonconventional	2.2	4.1	5.8	7.4	8.9	10.2
OPEC NGL/ nonconventional	**4.1**	**5.7**	**6.8**	**7.8**	**8.8**	**9.8**
OPEC crude	**31.1**	**30.2**	**33.8**	**38.2**	**43.5**	**49.3**
World	**83.3**	**89.7**	**96.5**	**103.5**	**110.4**	**117.6**

[1]Organization for Economic Cooperation and Development. [2]Developing countries. [3]Former Soviet Union.
Source: OPEC

DISTILLATION CAPACITY ADDITIONS BY REGION AFTER 2006*

Fig. 2



*Project only, excluding capacity creep. Total is 7.4 million b/d.
Source: OPEC

Upstream investment

These projections underline the need for substantial investment along the entire supply chain. Expansion of non-OPEC capacity is 2-3 times more costly than in OPEC, with this gap expected to widen over time (Fig. 1). The highest cost region is the OECD, which also experiences the highest production decline rates. Up to 2030, total upstream investment requirements, from 2006 onwards, will amount to $2.4 trillion (in 2006 dollars). These estimates do not include necessary infrastructure investments.

The oil industry, guided by the recent price trends, has mostly revised upward the business-as-usual crude oil price assumptions for medium to long-term analyses. Due to the effect of several factors, economic growth and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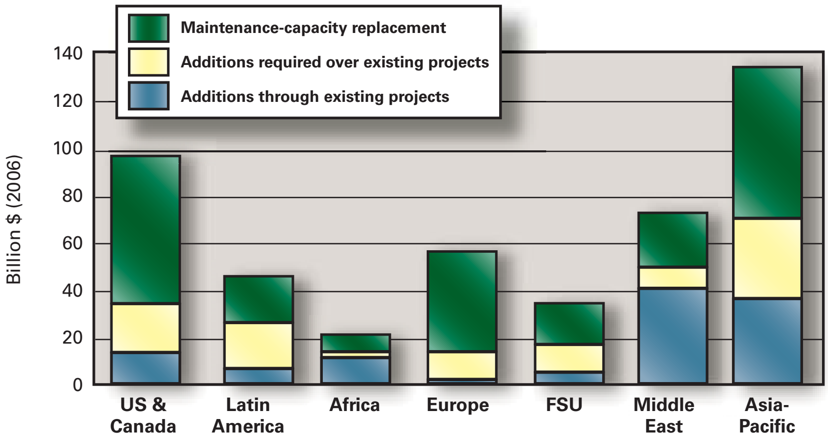
REFINERY INVESTMENTS, REFERENCE CASE, 2006-20

Fig. 3



Source: OPEC

oil demand are both more resilient to higher oil prices than had previously been thought. All these trends, in addition to rising costs, have become integral to the general perception of higher expected prices in the long-term.

Continuous downward revisions to the demand projections from organizations such as the International Energy Agency and the US Department of Energy's Energy Information Administration are also noted. In this regard, a key question is whether this downward revision process is set to continue. On the supply side, there has been a steady rise in expectations for non-OPEC production in the longer term. Increased attention is being paid to nonconventional oil and biofuels and a discernibly higher expected contribution to supply is emerging, according to OPEC's report.

There is much uncertainty over future demand and non-OPEC supply, which translates into large uncertainties over the amount of oil that OPEC member countries eventually will need to supply.

Because investment requirements are large and subject to considerably long lead-times and payback periods, it is essential to explore these uncertainties in the context of alternative scenarios.

Downside risks to demand are more substantial than upside potential. Energy and environmental policies in consuming countries and technological developments are important drivers that reduce demand, OPEC noted.

Uncertainties over future oil demand translate into a wide range of possible levels of necessary investment in OPEC member countries. Even over the medium-term to 2010, there is an estimated range of uncertainty of $50 billion for required investment in the upstream, increasing to $140 billion by 2015. This is partly why security of demand is a key concern for producers.

Downstream uncertainty

The expected increase in demand for oil products means an increasing volume of oil will need refining. Because the downstream sector is a key element of the supply chain and ultimately, market stability, it is important to focus attention on refining. In addition to rising demand, there is a continued move towards lighter and cleaner products. To meet this type of demand, the downstream sector will require significant investment to ensure that sufficient distillation capacity is in place, supported by adequate conversion, desulfurization, and other secondary processes and facilities, the OPEC analysts said.

The reference case for refining capacity expansion estimates that out of 14 million b/d of announced projects, over 7 million b/d of new capacity will be added to the refining system globally by 2012 (Fig. 2). Almost 70% of the new capacity will be in the Middle East and Asia-Pacific. The global reference case capacity additions from existing projects could reach slightly more than 9 million b/d by 2015 when capacity creep is added to the mix. Capacity creep is the unannounced capacity expansion through minor projects at existing facilities. The average rate of creep in the US in recent years has been 0.5-0.75%/year for crude units and 0.75-1.5%/year for upgrading units.

However, the additions could change because of rising downstream sector construction costs and difficulties in finding skilled labor and experienced professionals. This adds to the downside risk in the reference case.

"This risk is further exacerbated by the reluctance of refiners to expedite the implementation of projects in light of the rapidly changing policies that put a strong emphasis on developing alternative fuels that compete directly with refined products," OPEC reported. "These issues play out in the alternative 'cost-driven delayed' scenario for short and medium-term capacity expansion." In this scenario, the new distillation capacity additions could be reduced to as low as 8 million b/d through 2015, "including assumed capacity creep."

During the next 3 years, refinery capacity expansion under the reference case for refinery projects will just keep pace with the required incremental refinery throughputs. The deficit is small, but does not indicate any potential easing of refinery capacity and utilizations in the shorter term. The "cost-driven delayed" scenario for capacity additions worsens the deficit.

Nevertheless, under the reference case outlook for refinery projects, the data indicates that capacity additions should exceed requirements in 2011-12 as a range of new projects comes on stream, easing refining tightness and potentially, margins.

Under the "cost-driven delayed" scenario, the excess additions relative

OPEC sees flat demand for members' crude in '08

The Organization of Petroleum Exporting Countries expects demand for its members' crude oil to change little next year as limits on global refining capacity continue to support oil prices.

In its July Monthly Oil Market Report, OPEC projects a rise in global oil demand next year of 1.34 million b/d following an expected 1.25 million b/d increase this year. Its projection for average annual oil demand next year is 86.94 million b/d.

Most of the demand growth will occur in Asian countries other than those that belong to the Organization for Economic Cooperation and Development and the Middle East.

Among members of the OECD, representing most of the industrialized countries, demand growth will be confined to a 300,000 b/d gain in the US.

OPEC's demand forecast for 2008 assumes growth in global gross domestic product of 4.9%, fractionally below the increase expected this year.

Depending on variables such as economic growth, weather, and response to elevated product prices, the global oil demand increase next year could be as high as 1.45 million b/d or as low as 1.2 million b/d, OPEC says.

The exporters' group sees an increase in non-OPEC oil supply next year of 1.01 million b/d to an average of 51.42 million b/d.

The biggest regional non-OPEC supply change will be an increase of 460,000 b/d from the Former Soviet Union to an average of 13.08 million b/d.

FSU increases by major country are Russia, 180,000 b/d to 10.07 million b/d; Azerbaijan, 180,000 b/d to 1.09 million b/d; and Kazakhstan, 100,000 b/d to 1.48 million b/d.

OPEC expects nonmember oil supply gains next year of 290,000 b/d to 4.82 million b/d in Latin America, 220,000 b/d to 14.59 million b/d in North America, 120,000 b/d to 740,000 b/d in OECD Pacific, 90,000 b/d to 2.812 million b/d in non-OECD Asia, and 60,000 b/d to 2.86 million b/d in Africa.

The group predicts that output of NGLs and nonconventional oil by its members will rise 410,000 b/d to 4.8 million b/d next year and expects demand for its members' crude to average 30.7 million b/d, about this year's level.

OPEC expects global refining capacity to increase by less than demand in 2008—1 million b/d with most of the new capacity coming on stream late in the year.

"Overall, the outlook for the oil market in 2008 is shaping up to be quite similar to the current year, with continued tightness in the downstream supporting high product prices and frequent refinery outages exerting further upward pressure, despite the healthy crude oil market," OPEC said.

to reference requirements are essentially eliminated. Moreover, if global oil demand growth moves below reference case levels, an easing in the refining sector could begin as early as 2008.

The uncertainties surrounding these projections are especially relevant for biofuels. In general, biofuels projects do not take as long to implement as refinery projects. The reference case allows for a significant medium-term increase in biofuels production. Any additional increase would further reduce required refinery throughputs and margins. Consequently, policy initiatives supporting the development of biofuels may discourage crude oil producers and refiners from investing in needed capacity expansion.

Refinery tightness

"Should such a situation be followed by biofuels failing to meet the stated targets, the result could be further tightness in the downstream, and possibly the upstream, and in turn, this could have a significant impact on prices, margins, and volatility," OPEC said.

Biofuels also raises issues over the future structure of a complex downstream business that includes both oil and biofuels. The question is how to structure it to withstand major disruptions.

"With the increasing number of biofuel producers, the chances of losing this capacity for a longer period and over a larger area, for example due to drought, could easily lead to a shortage of required fuels," OPEC reported. Under these circumstances, the follow-up question is whether refiners should hold sufficient spare capacity to cover potential losses. OPEC member countries have offered, and will continue to offer, an adequate level of upstream spare capacity for the benefit of the world. It is equally important, however, that adequate capacity also exist downstream at all times, which is primarily the responsibility of consuming nations.

Based on the reference case assessment of known projects, by 2015 a total of almost 2 million b/d of additional distillation capacity will be required, and by 2020, a further 3.7 million b/d. "This is what is needed, on top of the assessed likely capacity additions, to bring the global refining system back into long-run balance, with refining margins that allow for a return on investment, but are not as tight as those of today."

OPEC said that, taking into account the most likely changes in the future supply and demand structures and their quality specifications, "the global downstream sector will require 13 million b/d of additional distillation capacity in the 2006–20 period—about 7.5 million b/d of combined upgrading capacity, 18 million b/d of desul-

furization capacity, and 2 million b/d of capacity for other supporting processes, such as alkylation, isomerization, and reforming (Fig. 2)."

The total required investment in refinery processing to 2020 is projected to be $450 billion in the reference case. Of this, $110 billion comprises the cost of known projects, $110 billion covers the further required process unit additions, and $230 billion comprises continuing maintenance and replacement. The Asia-Pacific area, which accounts for 68% of developing-country growth and 58% of world increases, requires the highest level of investment in new units to 2020, with China accounting for about 75% of the Asia-Pacific total (Fig. 3).

Interregional oil trade should increase by 13 million b/d to almost 63 million b/d of oil exports in 2020. Both crude and products exports will increase appreciably, with products exports growing faster than oil exports.

AVERAGE QUALITY SPECIFICATIONS OF GLOBAL CRUDE — Table 4

	2005	2010	2015	2020
API gravity, degrees	33.6	33.5	33.3	33.1
Sulfur content, %	1.2	1.3	1.3	1.4

Source: OPEC

"Correspondingly, the reference case outlook calls for a total tanker fleet requirement in 2020 of 460 million dwt. This compares with 360 million dwt at yearend 2006," said OPEC analysts.

Environmentally driven regulations also play an important role in respect to the refined products quality specifications (Table 4). Clearly, this trend is set to continue in the future, creating a potential for market fragmentation unless regulations are introduced in a coordinated manner. Therefore, future quality regulations should, as much as possible, ensure the fungibility of fuels to avoid shortages and prevent unnecessary volatility in product and oil markets. ✦

API: Industry environmental outlays hit $12.4 billion

Paula Dittrick
Senior Staff Writer

The American Petroleum Institute reports the US petroleum industry spent about $12.4 billion on the environment and on environment-related research and development during 2005.

It was the highest environmental-related expenditure total since 1990, API said in an annual report released in June.

Of the 2005 total, statistics indicate $10.7 billion was spent to implement technologies, create cleaner fuels, and finance environmental initiatives. Another $1.7 billion was spent for research and development, corporate environmental programs, and spill remediation.

API statistics since 1990 show the industry's lowest environmental expenditures for any one year were $7.5 billion during 1999, which coincided with low oil and gas prices. Expenditures have climbed fairly steadily every year since then, records show.

The industry has invested more than $148 billion since 1990 toward improving the environmental performance of its products, facilities, and operations. This works out to $504/person based upon a US Census Bureau population estimate of 296.6 million.

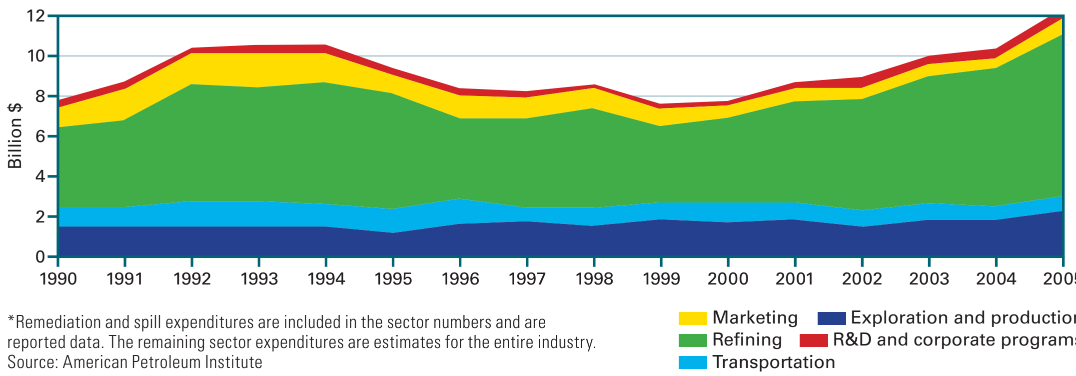
About 64% of the industry's environmental expenditures in 2005 targeted air pollution abatement, meeting or surpassing the requirements of the 1990 Clean Air Act.

Hazem Arafa, API director of statistics, said he had expected the numbers to go up in 2005 compared with previous years. Ultralow-sulfur diesel regulations drove 2005 downstream expenditures of $8 billion, and increased drilling activities drove exploration and production expenditures of $2.28 billion for that year.

Since 1990 API reports environmental spending by refiners of nearly $84 billion while E&P spending on environmental expenditures during that same time was $28 billion. The 10-year total for refining was nearly $50 billion compared with $16.5 billion for E&P.

"The operating and maintenance spending numbers are pretty consistent over the last 3-4 years, or they just

US ENVIRONMENTAL EXPENDITURES BY SECTOR*



*Remediation and spill expenditures are included in the sector numbers and are reported data. The remaining sector expenditures are estimates for the entire industry.
Source: American Petroleum Institute

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Investing in oil sands

Depending on how you look at it, an investment in Canada's oil sands could bring you untold wealth or—depending on certain environmentalists—not.

First, the wealth. According to at least one investment strategist we know, oil sands may represent an extremely worthwhile investment, with numerous factors pointing to long-term positive performance in the sector.

These factors, one analyst tells us, include technological progress, a safe geopolitical situation, high levels of investment, and rising profits.

Due to technological progress, we are told, production costs of about $20/bbl and an international oil price of more than $40/bbl means that the extraction of oil from oil sands is now highly profitable.

Rising profits

Our financial analyst said further advances in extraction technology could reduce operational costs to $10/bbl, meaning even higher profit margins.

As for a safe geopolitical situation, there are probably fewer countries on earth that have a safer one than Canada. Care to try your luck in Venezuela, which also has oil sand deposits? Keep in mind Hugo Chavez before you go.

Also, in Canada there is already a high level of investment in oil sands development. In fact, we are told that Lehman Bros. investment bank estimates that the Canadian oil industry will invest about $85-90 billion (Can.) in oil sands projects over the coming years.

As a result, our financial adviser said, oil sands are not just a prospect for the future. "The Canadian oil sands industry is largely well-established and already makes substantial profits," she said. Still, one might have to consider other forces that could upset such an investment—and one does not have to factor in the political vagaries of an Iran, Russia, or Ecuador. Nope. On this one, the upset factor lies much closer to home.

Opposed by environmentalists

According to recent reports, leading US environmentalists have taken up space in Calgary due to the rising economic importance of Canadian oil sands as well as growing concern about global warming. In fact, over the past 6 months, US groups such as the Natural Resources Defense Council, the Sierra Club, and Environmental Defense have stepped up their participation in Canada's public meetings and on regulatory matters.

According to Robert Page, senior adviser to Canadian power producer Transalta Corp., the presence of such groups, which are financially better able than their Canadian counterparts, means the environmental campaign has more power behind it.

The environmentalist campaign, coming even as oil sands production continues to grow, says the process is energy intensive and that it results in huge quantities of carbon dioxide emissions, linked by scientists to global warming.

As a result of their concerns, the National Resources Defense Council has sharpened its focus—and probably its knives, too—on the development of Canada's oil sands.

Needless to say, that could have an adverse effect on investment portfolios that include oil sands developments. See your financial advisor—pronto. ✦

increased a little because the refining capacity is going up," Arafa said. "It's really the capital expenditure numbers that make the total numbers oscillate up and down. Those are usually driven by certain mandates or regulations, and that is why they spike up."

The US has experienced the equivalent of increased refining capacity of one refinery every year for 10 years, he said.

"Just to put it in perspective, the refining industry has spent $50 billion in the last 10 years on cleaning the environment. That $50 billion could have built an extra 12 refineries, so it's significant spending," Arafa said.

API's data include survey responses and federal statistics. The environmental expenditures survey is sent to a sample of the industry representing all large and midsize companies along with a randomly selected group of smaller companies.

In 2005, 72 companies completed the survey. ✦

Brazilian police arrest Petrobras, shipyard executives

Eric Watkins
Senior Correspondent

Brazilian federal police arrested three top executives of state-owned Petroleo Brasileiro SA (Petrobras) on July 10, along with the directors of three shipyards—Angraporto Offshore, Maua Jurong, and IESA—and others for alleged involvement in fixing repair contract bids for at least three offshore oil platforms.

The senior Petrobras officials include Carlos Alberto Pereira Feitosa, coordinator of Petrobras's bids commission; Carlos Heleno Netto Barbosa, managing director of the company's services unit; and Romulo Miguel de Morais, director of platforms. Arrest warrants also were issued for Carlos Roberto Velasco, a

member of the company's bid commission, and for Petrobras employee Jose Antonio Vilanueva.

Angraporto's three main directors, Mauro Luiz Soares Zamprogno, Wladimir Pereira Gomes, and Fernando da Cunha Sterea all were arrested and are being questioned in connection with the allegations of corruption and money laundering.

In addition, agents arrested Simon Clayton, the executive director of TBS International's Brazilian affiliate TBS do Brasil, who was linked to Angraporto, described as being "at the heart" of the irregularities.

Arrest warrants also were issued for one of the shareholders in IESA's shipyard, Valdir Lima Carneiro, as well as for Paulo Jose Freitas de Oliveira and Antonio Carlos Vargas, who served respectively as the corporate and industrial directors of the Maua Jurong yard.

The schemes worked by Petrobras employees passing inside information to Angraporto Offshore to fix bids in its own favor, officials said. Angraporto was created in July 2003 to take up administrative contracts with Petrobras, and won three contracts, valued at $32 million, to refurbish and repair the three oil platforms.

Angraporto oversaw refurbishment of the P-10 oil platform, while IESA and Maua Jurong allegedly worked with Angraporto to promote fraud in the bids involving the other two platforms, the P-14 and P-16.

Brazil's federal police are said to have worked on the case with full support from Petrobras. In a statement, the Brazilian firm said: "At the request of the prosecutor, Petrobras has not taken any position so as not to prejudice the investigations. The company has suspended the employees from their functions and installed a commission to eliminate immediately any possible irregularities."

Altogether, Brazilian federal police arrested 13 people following recent calls for greater accountability by the firm's chief executive officer (OGJ Online, July 12, 2007). ✦

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Basell to buy Lyondell Chemical in $19 billion deal

Polyolefins manufacturer Basell Service Co. BV plans to buy Lyondell Chemical Co. of Houston for about $12 billion, plus the assumption of Lyondell's $7 billion debt. The transaction will create one of the world's largest chemical companies.

In other recent company news:

- Plains Exploration & Production Co. has agreed to acquire Pogo Producing Co. in a cash and stock deal valued at $3.6 billion.
- Statoil ASA and Norsk Hydro ASA shareholders approved the merger of Statoil and the oil and gas division of Hydro during separate July 5 extraordinary general meetings.
- Chesapeake Energy Corp. and Anadarko Petroleum Corp. have entered into multiple agreements, including a joint venture involving the companies' separate assets in the Deep Haley area of the Delaware basin in West Texas.
- Constellation Energy Partners LLC, Baltimore, said it will become one of the Cherokee basin's largest producers when it acquires Amvest Osage Inc., a unit of private Amvest Corp., Charlottesville, Va.
- Petro Rubiales Energy Corp., Vancouver, BC, formerly Consolidated AGX Resources Corp., completed a $440 million (Can.) private placement and acquired 75% of Rubiales Holding Ltd. (RHL).

Basell-Lyondell deal

Basell, of Hoofddorp, the Netherlands, agreed to pay $48/share for Lyondell. The boards of both firms approved the acquisition. The transaction is expected to close within several months, subject to regulatory approvals and approval of Lyondell shareholders.

The combined 2006 revenues of Basell and Lyondell would have been $34 billion. Together, the two companies have 15,000 employees worldwide. New York industrial holding group Access Industries privately owns Basell.

Lyondell owns a 282,600 b/cd refinery in Houston that processes very heavy, high-sulfur crude. Executives said Lyondell's assets, access to raw materials, and refining capacity complements Basell's assets.

Basell produces polypropylene and advanced polyolefin products and provides technical services for its proprietary technologies. Together with its joint ventures, Basell has manufacturing facilities in 19 countries and sells products in more than 120 countries.

Lyondell manufacturers chemicals and plastics, refines heavy, high-sulfur crude, and produced ethylene, polyethylene, styrene, propylene, propylene oxide, gasoline, and ultralow-sulfur diesel. It produces fuel oxygenates methyl tertiary butyl ether and ethyl tertiary butyl ether.

Basell had been looking for chemical acquisitions. Recently Huntsman Corp. terminated a $5.6 billion agreement to be acquired by Basell. Huntsman agreed to be acquired by Apollo Management LP for $6.5 billion.

Plains E&P-Pogo deal

Pogo stockholders will receive 0.68201 share of Plains E&P common stock and $24.88 cash for each Pogo stock share, representing a total consideration of about $60/share. The transaction is subject to stockholder approval from both companies.

The transaction nearly doubles Plains E&P's production with the addition of substantial producing properties and significant growth potential in Texas, primarily the Panhandle, Permian, and Gulf Coast regions, as well as the prolific Madden field in Wyoming and the San Juan basin in New Mexico.

The Pogo assets are complementary to the Plains E&P's assets, having long production lives and low decline rates. At yearend 2006 pro forma for asset sales, Pogo reported proved reserves of

PERSONNEL MOVES AND PROMOTIONS

Aurora Oil & Gas makes executive changes

Aurora Oil & Gas Corp. has added the responsibilities of president to Chief Financial Officer **Ronald E. Huff**. He succeeds **William W. Deneau**, who will focus on his duties as chairman and chief executive officer.

Huff has more than 25 years of oil and gas industry experience. He has been serving as the company's chief financial officer since June 2006.

Previously he served as president and chief financial officer of Belden & Blake Corp. and has worked for Transco, Sonat Inc., and Zilkha Petroleum.

Separately, **John C. Hunter** was named AOG's vice-president, exploration and production. Hunter is a petroleum engineer with more than 30 years of industry experience. Prior to joining AOG in 2005, he worked for Wellstream Energy Services and Torch Energy Advisors, both of Houston.

Thomas W. Tucker, one of the founders of Aurora Energy Ltd., which merged with the company in 2005, retired effective June 30. The company will retain Tucker as a consultant through Dec. 31 to assist on various matters.

Other moves

South Texas Oil Co. has appointed **J. Scott Zimmerman** president and **Bill Zeltwanger** vice-president.

Since 2004, Zimmerman served as president and chief executive of Storm Cat Energy, a publicly traded company that he founded.

In 2002 he was vice-president of operations and engineering for Evergreen Resources, overseeing more than 1,000 producing wells and 800,000 prospective acres. In 2004 Evergreen was acquired by Pioneer Resources for $2.1 billion.

Zimmerman's oil and gas industry experience also includes a 20-year tenure at Huber Corp., where he was instrumental in the sale of Huber's Fruitland coalbed methane field, a deal that netted more than $100 million in profit.

Zeltwanger for the past 6 years has been a partner in Giddings, Tex.-based Leexus Oil & Gas LLP, which recently sold its assets to South Texas Oil for $26 million. He began his oil and gas career in 1973 in South Texas and later worked with assets in the Austin Chalk and several new Wilcox field discoveries in Fayette and Lee counties in Texas.

Rosetta Resources Inc. has named Executive Vice-Pres. **Charles Chambers** acting president and chief executive officer.

Chambers is a 32-year oil and gas veteran, who has helped with the development of the Houston independent since its inception. He succeeds **Bill Berilgen**, who resigned as chairman, president, and chief executive.

Chambers has founded several companies, including Buena Vista Oil & Gas and Chambers Oil & Gas Inc. He served as vice-president, corporate development, for Sheridan Energy Inc. from 1997 to 1999 when Sheridan was acquired by Calpine Natural Gas LP, where he remained until March 2001 as vice-president, business development and land.

Separately, **Henry Houston**, chairman of Rosetta's audit committee, has been selected as chairman of the company. He will lead the board in its search to identify a permanent chief executive, Rosetta said.

Philip Mandelker, general counsel of Zion Oil & Gas Inc., Dallas, since April 2000 and a director since 2001, has been appointed executive vice-president.

Mandelker was involved in a recent initial public offering of Zion, which operates an onshore oil and gas exploration concession in Israel.

St. Mary Land & Exploration Co. has appointed **Lehman E. Newton III** vice-president, regional manager, of the Permian region.

Newton succeeds **Jerry Schuyler**, senior vice-president, regional manager, Greater Gulf Coast region, who has resigned. The company has not yet selected a regional manager for the Gulf Coast region.

Newton began his career in 1979 with ARCO and held positions of increasing responsibility in engineering, operations, and business development through 2000. Newton then founded and subsequently sold a private exploration and development company focused on the Permian basin. He has worked for Unocal Corp. subsidiary Pure Resources Inc., as well as its predecessor Chevron Corp. Most recently, he served as general manager of St. Mary's Midland, Tex., office, which he helped open in February.

St. Mary's Permian basin assets will be managed out of the Midland office, which was opened following the acquisition of the Sweetie Peck assets in December 2006. The remaining onshore Texas, Gulf Coast, and Gulf of Mexico assets will be managed by its Houston office.

219 million boe.

Upon closing, which is expected in the fourth quarter, Plains E&P will have a proved reserves base of 635 million boe. Proved, probable, and possible reserves potential is estimated at 1.4 billion boe.

Plains E&P is considering creating a master limited partnership as well.

Statoil-Hydro merger approved

Statoil's merger with Hydro, valued at $30 billion, will create the world's largest offshore operator (OGJ, Jan. 1, 2007, p. 29).

The merger, approved by the boards of directors of both companies in March, is expected to be completed on Oct. 1.

The new firm will be based in Stavanger. Group functions will be in

Stavanger and Oslo, however, and the chief executive officer will operate from both locations.

Chesapeake-Anadarko JV

Chesapeake and Anadarko, which currently operate a total of 16 drilling rigs in the Deep Haley area, plan to conduct an aggressive drilling program for the area and could increase their drilling activity as the joint venture develops.

Under the agreements, the companies are obligated to jointly evaluate and explore more than 1 million gross acres in the Deep Haley area and share drilling, completion, production, and midstream operations on a roughly 50-50 basis.

The deal afforded Anadarko about $310 million in cash and other consideration, including reimbursement of capital expenditures previously incurred in connection with the development of its Deep Haley properties and Chesapeake's commitment to fund a portion of Anadarko's future Deep Haley area capital costs. In addition, Anadarko obtained 50% of certain Chesapeake nonproducing leasehold interests in Loving County, Tex.

Chesapeake received:

- 25% of Anadarko's existing Deep Haley area production.
- 25% of Anadarko's leasehold in the central and eastern portions of the Deep Haley area.
- 50% of Anadarko's leasehold and contractual rights in the western portion of the Deep Haley area.
- A lease from Anadarko on 2,100 net acres in the Fayetteville Shale play in Arkansas.
- An assignment of 5,600 net acres of undeveloped leasehold in the Anadarko basin in western Oklahoma.
- The Oklahoma City real estate assets acquired by Anadarko last year as part of its acquisition of Kerr-McGee Corp.

The Deep Haley area in West Texas has recovered more than 1.4 tcf of gas from over-pressured Pennsylvanian formations, said Anadarko. The company started work in the basin in 2003 and has accumulated the rights to over 400,000 net acres in the area.

Chesapeake, a veteran in the area, has generated during May a combined 90 MMcfd of gas equivalent of gross production from its most recent seven wells in the Deep Haley area.

Constellation buys Amvest unit

Constellation is to pay $240 million for Amvest Osage, closing by the end of July. Constellation already owns Cherokee basin assets.

Amvest Osage averages 16 MMcfd of net gas production from 370 producing wells from 93 bcf of proved reserves as of Mar. 31 at $8.48/MMbtu (OGJ Online, Aug. 16, 2005). The seller has identified more than 1,000 drilling and recompletion opportunities. It has a 13-year exclusive concession from the Osage Indian Nation for CBM and shale rights on 560,000 contiguous net acres with potential for as many as 100,000 additional acres. The flexible concession agreement provides for leasing as drilling occurs.

Petro Rubiales private placement

RHL owns 100% of Meta Petroleum Ltd., which has interests in the Rubiales, Piriri, and Quifa blocks in Colombia and produces more than 18,500 gross (5,000 net) b/d of 12.5° gravity oil from the Rubiales and Piriri association contracts in the Llanos basin (OGJ Online, Feb. 9, 2006).

Meta proposes to hike the heavy oil production rate to 66,000 b/d by drilling clusters of one vertical and four to five horizontal wells with downhole submersible pumps in giant Rubiales field in Meta Department. An estimated 200 new wells are required to boost output to more than 126,000 b/d.

The field produces from the Tertiary Carbonera formation at less than 3,000 ft. The association contracts remain in force until July 2016.

A pipeline to Cusiana Station in Casanare Department from Rubiales field is needed to replace trucking of crude and cut transportation cost. The 215-km line, with ultimate capacity of 200,000 b/d, is to be completed by June 2009.

Meanwhile, Petro Rubiales granted Pacific Stratus Energy Ltd. an option to earn up to 50% of the Petro Rubiales interest in Quifa by funding Petro Rubiales' share of exploration costs estimated at $5.3 million. ✦

LEAN ENERGY MANAGEMENT—12

Gas-to-electricity real options can provide deepwater strategic, operational flexibility

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Computer Aided Lean Management (CALM) uses software for the optimization of profitability under uncertainty.

CALM technologies add two kinds of flexibility to traditional economic analyses in order to better deal with uncertainties common to the oil industry today.

The first is strategic flexibility, used to dynamically manage portfolios of potential investments to take advantage of volatility in the marketplace, changes in exogenous forces, and the long-term uncertainties of reservoir performance.

The second is operational flexibility, used to manage the shape and mix of the production within fields in order to maximize value extraction.

We present below scenario and real options analyses that demonstrate the value of the flexibility that CALM brings to strategic and operational decision-making in ultradeepwater development.

Our analyses suggest that additional enterprise value going forward can be created through the addition of a gas-to-electricity option using a new kind of offshore hub centered around floating generation, sequestration, and offloading (FGSO) vessels and undersea high voltage DC (HVDC) power cables to shore.

Strategic flexibility

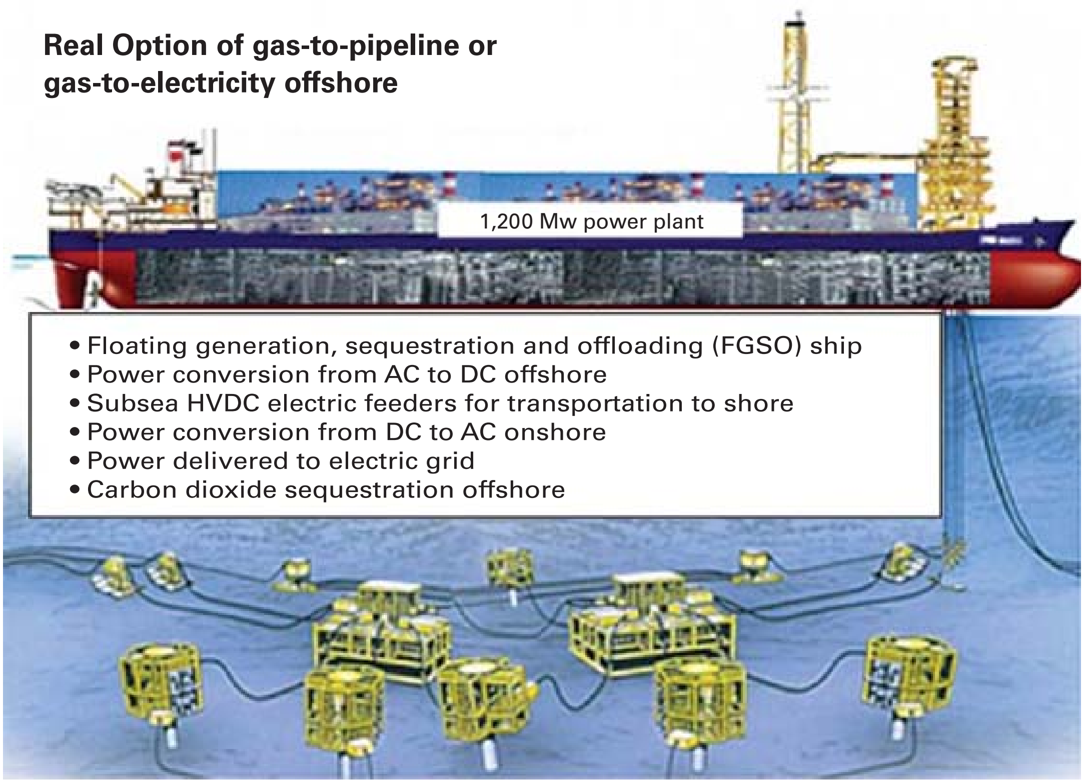
Most businesses decide future changes in strategy based on past decisions on investments, resources, systems, and operational capabilities. These decisions have created core competencies within each firm that define who they are in their industry.

The evaluation of future investment options based on potential changes in exogenous forces (supply/demand, geopolitical, climatic) through scenario and real options analyses can provide rich alternative investment strategies to consider in today's volatile business climate.

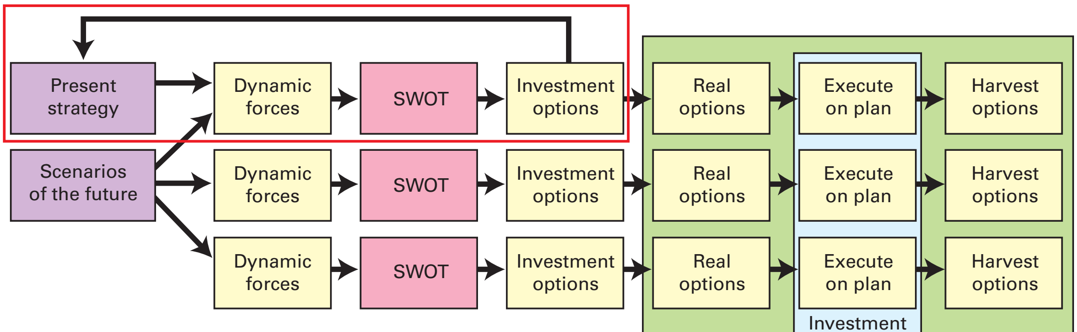
The dynamics of geopolitical uncertainty, always a risk in the oil and gas industry, are compounded by uncertainties arising from potential consequences of global climate change and supply/demand shortages and excesses.

We have evaluated scenarios concerning

FGSO VESSEL CONCEPT FOR DEEPWATER GAS-TO-ELECTRICITY CONVERSION Fig. 1



DELAY MAJOR CAPITAL SPENDING UNTIL LAST POSSIBLE MOMENT Fig. 2



SWOT stands for strength, weakness, opportunity, and threat analysis.

how to maintain profitability in ultradeepwater production with the world moving towards a "green" economy in which there are significant new penalties for carbon emissions and most end-use is via electricity and heating. In such scenarios, a modern oil and gas company must consider its real options for remaining profitable in the face of potential new carbon taxes, sequestration requirements, and competition from coal gasification.

Climate change, combined with governmental action (at the state if not the federal level), creates opportunities to transform how energy is economically delivered to customers, particularly from ultradeepwater areas, where capital costs are already the largest faced by exploration and production companies today.

The maintenance of a real option for conversion of gas-to-electricity at FGSO hubs can allow future transport of electricity using undersea HVDC cables to electricity markets. Such an option can be exercised when a positive "spark spread" exists between the price of electricity vs. natural gas from ultradeepwater production (Fig. 1).

Given the uncertainty of future geopolitics, technology development, and international competition, we show that making significant investments based purely on the existing paradigm of oil and gas market dynamics can easily result in lost opportunity at best or bankruptcy at worst.

An alternative approach is to use CALM real options and scenario analyses to create alternative investment options to capture "out-of-the-box" opportunities without making significant commitments of capital investment until absolutely necessary (Fig. 2).

Maintenance of a real option to produce gas-to-electricity offshore provides a compelling argument to make potential investments in a new generation of production technologies that we call "FGSO" vessels. Our analysis shows that the opportunity is at least as large as that realized in the last 15 years from the invention and widespread deployment of floating production, storage, and offloading (FPSO) vessels.

Commitment of capital in a resource-constrained business such as oil and gas without immediate increases in enterprise value is similar to storage of products in a warehouse. There is great risk that the products stored will lose value or become obsolete (c.f., the current US automobile business).

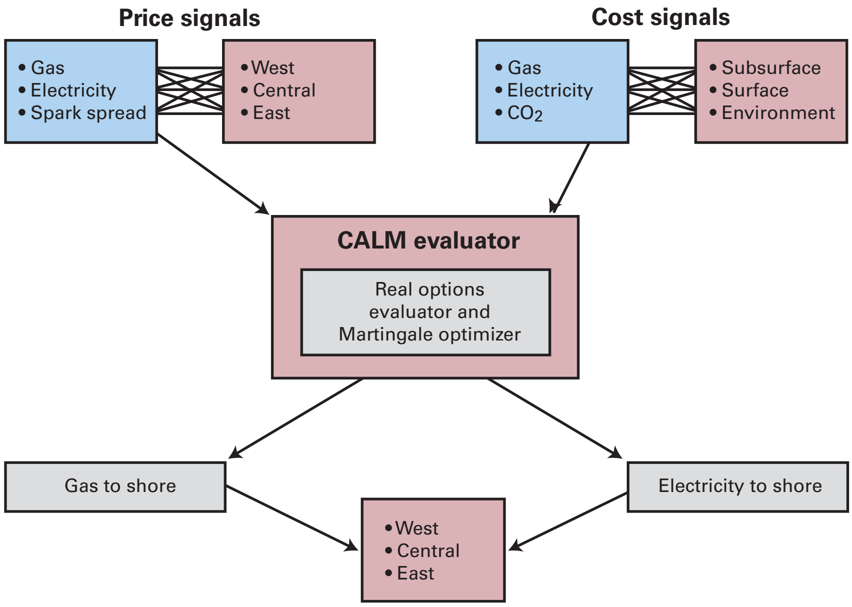
The imperative to delaying capital commitments as long as possible as dynamic forces change, while anchoring in the real options to enable entry into emerging markets, is a major component of CALM theory (Fig. 2).

Operational flexibility

Once capital investments have been made, CALM controllers provide the mechanism for computing the real option value of added capabilities that arise from swapping delivery of variable product-mixes to multiple, asynchro-

MARTINGALE CONTROLLERS NEEDED TO MANAGE REAL OPTIONS*

Fig. 3



*Controllers needed because gas and electricity prices and costs vary simultaneously.

nous markets.

Price signals that vary by geography, such as those in the energy markets for natural gas and electricity in the southern US, qualify for such real options considerations for ultradeepwater production from the Gulf of Mexico.

In order to take full advantage of dynamic differences in commodity prices, producers in the gulf would need to add additional real options of selling electricity generated offshore from produced gas, paired with potential trading in carbon dioxide credits from sequestration at the source of the production.

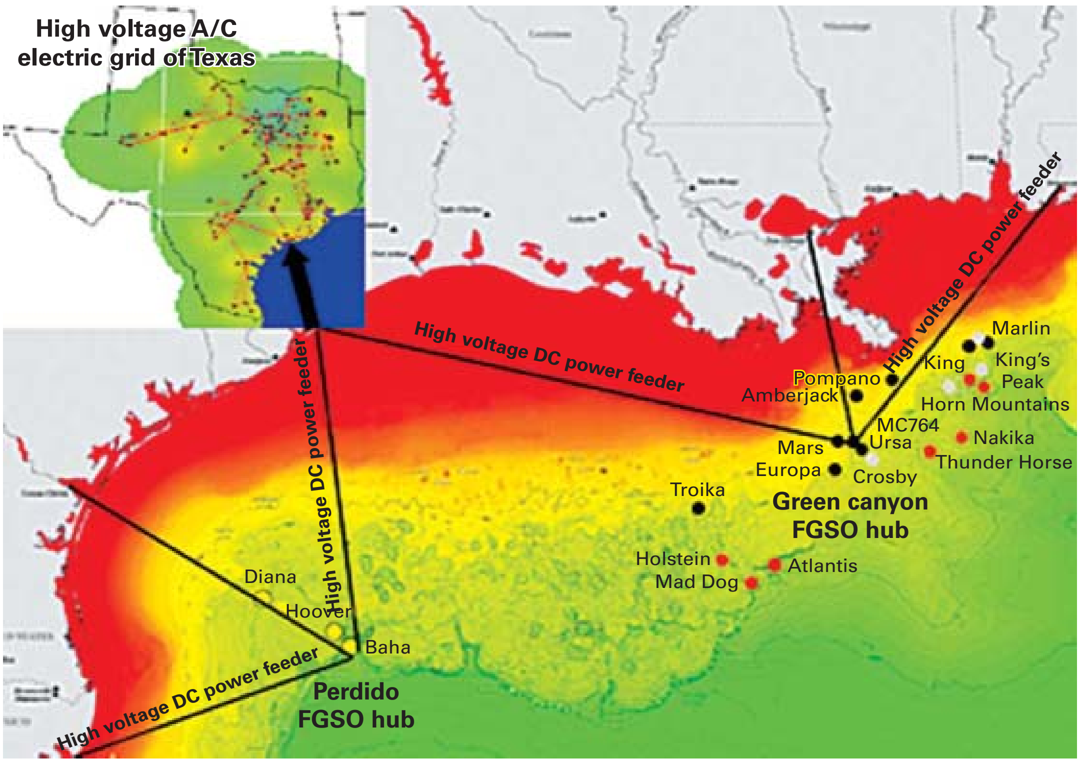
If price and cost signals are both received in real time, and if sufficiently diverse product and sequestration options exist, then CALM's martingale controller concept (described in past articles in this series) could produce the added value required to justify the large additional capital investment. Such smart controllers are especially useful in out-of-sync quadrants of our scenario analysis when either positive or negative spark spreads exist.

In 2005-07, regional spark spread premiums of ±$20/Mw-hr equivalent between the electricity and natural gas prices have been common. These variations were caused by electricity congestion in the summers and gas shortages in the winters.

WESTERN AND EASTERN GULF ULTRADEEPWATER GAS-TO-ELECTRICITY HUBS

Fig. 4

Imagined FGSO vessels and undersea HVDC power cables are combined into hub-and-spoke networks



CALM's martingale controllers incorporate dynamic real options to compute optimal decision paths that are "always-in-the-money." When controlling ultradeepwater production, they would simultaneously balance price signals against production costs to distribute gas vs. electricity into different regional markets in real time (Fig. 3).

Gas-to-electricity offshore

The value of investment in real options comes not from the addition of new kinds of power delivery systems to the market mix but from the modest initial investments needed to enable the possible selection of options such as FGSO hubs at a later date. The timing and volume of gas and oil streams piped to shore are the only current options available to ultradeepwater operators.

What would be required to generate such additional options of selling electricity generated by burning gas at new offshore power hubs while sequestering CO_2 back into reservoirs to enhance production?

A similar paradigm change in offshore production methodology has been executed by the industry in the recent past. When the need for more diverse production and storage facilities was required in ultradeep water off Brazil and West Africa, FPSO vessels were invented. Today, more than 100 FPSOs have been built to exploit this need for additional flexibility at a cost of well over $75 billion.[1]

Would it be profitable to build FGSO vessels that use natural gas for power generation onsite and offload electricity instead via undersea (HVDC) cables connected to diverse electricity markets?

The vessels could also sequester CO_2 and use it for enhanced oil recovery (EOR) in the same reservoirs being used to fuel the floating power plants. The components exist to modify supertankers to contain modern, 1,200-Mw gas turbine power plants, along with AC/DC converters, and CO_2 sequestration capabilities.

We estimate that the cost would be about the same as FPSO vessels. One thousand miles of HVDC cable to carry the electricity to multiple shore locations could be laid with a traditional marine cable-laying ship for an estimated capital investment of about $1 billion.

Fuel-efficient, aeroderivative gas turbines with proven reliability in marine environments can be used to provide a high-density power plant.

Modularization would be used to provide enough mobility that components requiring overhaul could be offloaded for repair onshore. This modularity, combined with a modest amount of redundancy, has been demonstrated to deliver close to 100% availability in onshore gas turbine power plants.

Redundancy in AC/DC converters and HVDC cables can produce similar percentages of availability offshore while providing real options for redeployment amongst newly emergent markets, given the rerouting and splicing potential of flexible HVDC cable laid onto the sea floor. A hub-and-spoke design is envisaged for collecting the gas for powering the FGSO generators. CO_2 would be captured and returned to the gas fields for EOR sequestration (Fig. 4).

Ultradeepwater economics

We have used an American Options model to estimate the value of maintaining real options for construction and deployment of FGSO hubs in the ultradeep water (Fig. 5, top).

We then compared capital expenditures, real options, and strategic value with the more traditional net present value method of evaluating a five-step investment in the construction and deployment of an FGSO power production hub in the northern Gulf of Mexico (Fig. 5, bottom).

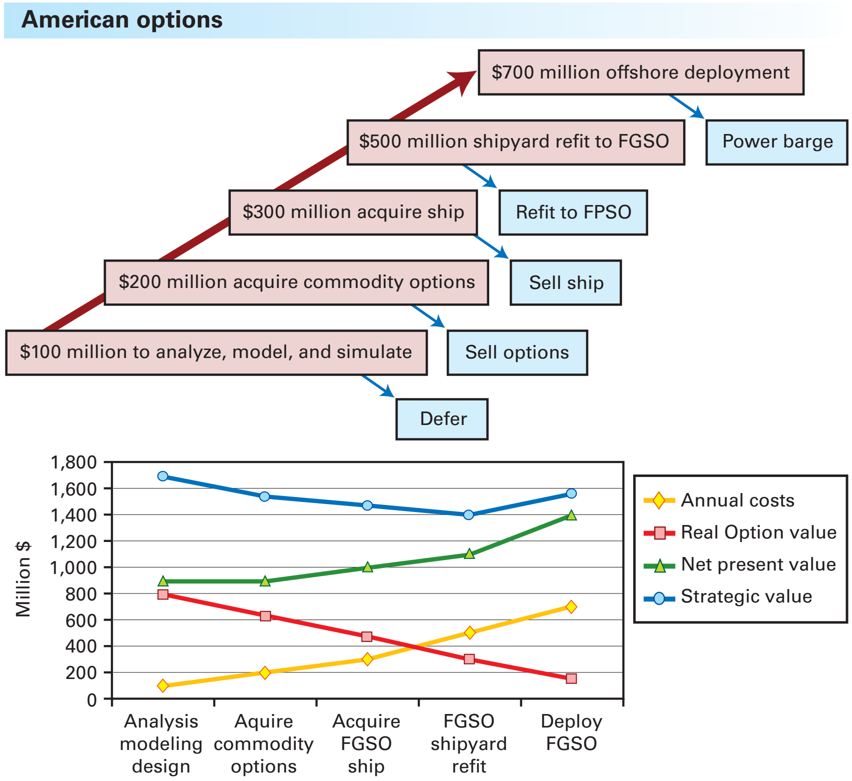
NPV-based investment decisions create biased and uncertain forecast-dependent valuations, especially for forecasts that are many years out. There are additional tradeoffs from the exercising of real options along the path to construction and deployment that can enable larger capabilities to profit when uncertainties solidify in the future. In other words, incremental investment in building the capacity to profit from the real options creates a dynamic plan with decision gates that force ongoing evaluation of capital investments.

There is always more certainty of the payback at a later date from any plan assembled today, and that advantage can be used to create a valuable, real options framework for any company. True, real options for those investments must exist, of course.

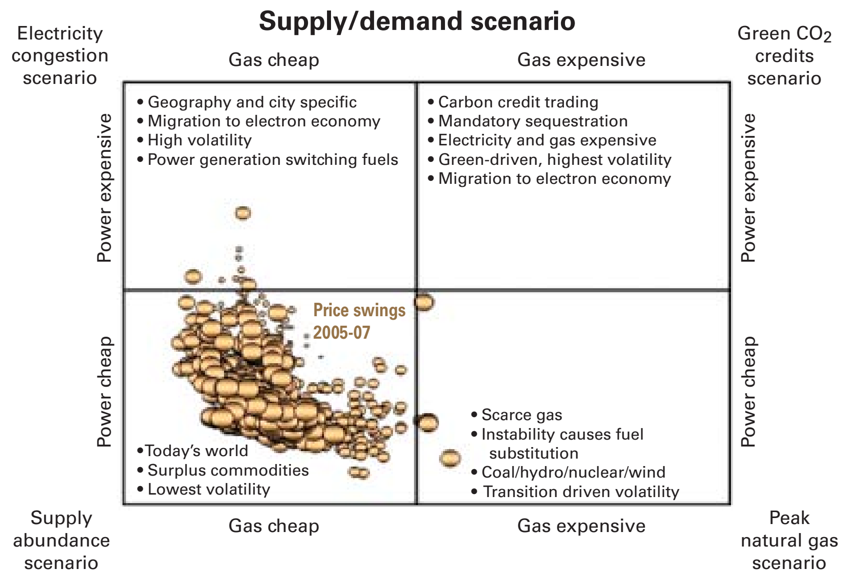
We conducted our evaluation of gas-to-electricity investment using the real options analysis tool kit in a common strategic planning tool used in the oil industry called "Crystal Ball."

Such real options are valid when

ANALYSIS OF STRATEGIC INVESTMENT IN AN FGSO HUB Fig. 5



PRICE SCENARIOS FOR THE FUTURE* Fig. 6



*Tracking of continuous price variations (real and futures) between electricity and natural gas for the Texas Gulf Coast from June 2005 (smallest bubbles) to December 2007 (largest bubbles).

management has the ability to decide if each successive stage can be implemented after the results from the previous stage are final. In such options, only the previous sunk cost is at risk at any stage.

The strategic value of being able to defer investments in order to wait and see until more information becomes available is the sum of the real option value and the NPV of the asset with cash discounted at the hurdle rate and volatility estimated. If, over time, the volatility decreases, then uncertainty and risk are lowered and the real option value decreases.

The cost-of-waiting is evaluated by computing the dividend rate as a percentage of the asset value. The balance between collecting more information and the cost of waiting is continuously recalculated so that the optimal strategic value can be maintained all along the way. The ability to wait, while simultaneously preparing all that is necessary to execute, is worth several hundred million dollars in the ultradeepwater FGSO hub case study (Fig. 5).

Scenario analysis

Real options combine naturally with scenario analysis.

Below, we demonstrate this capability by evaluating the profitability from the execution of the FGSO real options described above in a world in which gas and electricity prices are independently fluctuating at the same time that "green CO_2 credits" are being contemplated and congestion makes delivery even of abundantly supplied gas and electricity difficult. The value in these scenarios ultimately arises from the differences between natural gas and electricity prices (Fig. 6).

We assume price volatility is driven in the future by annual variations from summer to winter and occasional natural disasters like those from hurricanes Katrina and Rita.

Our scenarios were then compared with recent variations in commodity prices over the last 3 years. These mostly fall within the cheap electricity and gas scenario (lower left quadrant of Fig. 6). The upper right quadrant represents the green scenario that will likely result in a surcharge on current prices for both gas and electricity.

We foresee significant opportunities for carbon credits and an "electron economy" developing as energy use for transportation and heating migrates over to electricity. New technologies like plug-in hybrid vehicles and ultraefficient electric heat pumps will drive this conversion.

Harvesting of arbitrage between gas and electricity prices with positive or negative spark spreads, the other two quadrants of our scenario analysis, can be assured via the use of CALM martingale controllers. Significant profits can be assured by marketing a flexible mix over selling either gas or electricity in these highly variable price quadrants.

CO_2 sequestration

CO_2 removal offers additional real options of sequestration right at the source of ultradeepwater production to both enhance production through CO_2 flooding and profit from trading in carbon credits.

There is significant environmental upside from such real options. Given the assumption that the value of CO_2 sequestration would be high for the green scenario, returns from this investment are far above expected costs of capital to make this option real.

Consider the value of carbon sequestration at the site of ultradeepwater production should a carbon tax come into existence.

In Table 1, we compare offshore EOR using the CO_2 captured by the FGSO hubs with estimated costs for onshore carbon sequestration from the International Panel for Climate Change, United Nations, 2007. Injection at the source of ultradeepwater production could add a premium of $10-20/Mw-hr equivalent in our scenario, assuming that the profit range is $3.50-4.50/ton of CO_2 injected (current cost in West Texas).

Investment 'hockey stick'

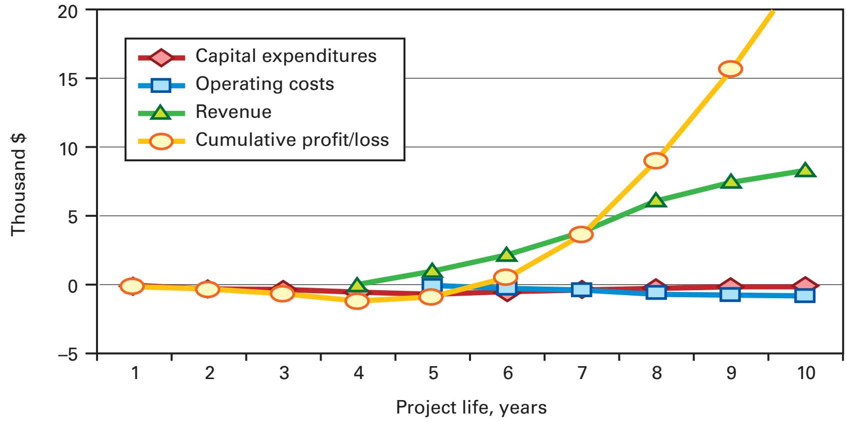
The real options valuation must be combined with estimated revenues and operational and capex costs into a profit/loss model in order to determine the investment quality of the venture (Fig. 7).

We compute a payback period of five years for capital investment in the FGSO hub, assuming an ultradeepwater production facility is connected to both a gas pipeline and an FGSO electricity/sequestration hub. Without the $20/Mw-hr carbon credit, the payback time would be 7 years.

DIP TO NEGATIVE CAPITAL LOSS BEFORE PROFITABILITY

Fig. 7

Enterprise emerges profitably as electricity production begins in fourth quarter of year four.



OFFSHORE CO_2 EOR, ONSHORE SEQUESTRATION COMPARED

Table 1

Carbon sequestration	Profit range, \$/ton CO_2	Remarks
Injection of effluent CO_2 from gas generation offshore into deepwater reservoirs	3.5-4.5, injected	CO_2 has never been available for deepwater injection for enhanced oil recovery. Little doubt CO_2 injection preferable to waterflooding.
Carbon sequestration	**Cost range, \$/ton CO_2**	**Remarks**
Capture from a coal-fired power plant	50-75, captured	Net costs of captured CO_2 compared with same plant without capture.
Capture from hydrogen, ammonia, or gas processing	5-55, captured	Applies to high-purity sources only.
CO_2 pipelines	1-8, transported	Per 250 km of pipeline at 5-40 tonnes/year of CO_2.
Aquifer storage on land	1-8, injected	Excludes monitoring and verification.
Ocean storage	5-30, injected	Includes transportation offshore 100-500 km.
Mineral carbonation	50-100, mineralized	Includes additional energy needed for carbonation.

Summary

Given long-term forecasts that are guaranteed to be wrong, a CALM methodology that utilizes real options, paired with scenario analyses, can provide a powerful means of exploring alternative investment options under uncertainties in dynamic and market forces.

The scenario analysis provides investment stages for real options evaluation so that alternatives for deployment of capital can be identified into the future. The economic model for evaluation of the ROI for ultradeepwater electricity production hubs using FGSO vessels and undersea HVDC power cables to shore requires recovery of capital costs and sufficient future market flexibility onshore to sustain profitability for the life of the hub.

Our evaluation suggests that additional real options for producing gas-to-electricity make an attractive alternative to the more traditional options of oil and gas delivery by pipelines. Our evaluation of a green scenario, whereby fear of climatic change produces a hefty new CO_2 tax, illustrates the need for strategic flexibility with real alternative

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

investment options in order to assure profitability for ultradeepwater production. ✦

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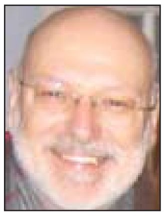
The authors



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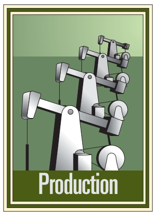
Upstream production capacities to advance in many countries

Guntis Moritis
Production Editor



Many oil and gas projects are set to come on stream in the next few years and help meet expected increases in the world's energy demands.

Table 1 lists numerous announced major upstream projects in 50 countries, including development of individual fields and the supporting infrastructure, such as:

- Projects for developing new oil and gas discoveries. The projects listed exclude many announced discoveries that are in delineation without publicly available development plans.
- Field redevelopments for recovering bypassed oil.
- Stranded-gas projects and projects to eliminate gas flaring. These projects often include new infrastructure such as pipelines for transporting gas to end users or facilities for producing LNG and GTL.
- Heavy-oil projects that may include such new infrastructure as pipelines, crude oil upgraders, and mines.
- Deepwater projects, some of which rely on long flowline tiebacks and hubs.
- Development of unconventional resources such as tight sands, shale gas, and coalbed methane gas.

If all the projects listed had a peak production rate in the same year, the total world production capacity would increase by 30 million b/d and 78 bcfd.

Operators, peak production

Although joint ventures operate some projects listed in Table 1, for simplification, the table only includes the name of one of the companies in the joint venture (see accompanying tabulation listing the company's parent firm's full name).

Table 1 shows the year in which the production from a project or a phase of the project may peak or enter a peak production plateau that could last for several years. Operators plan to develop many of the larger projects in several phases, as noted in the table.

Asia-Pacific

The Asia-Pacific region has several large LNG projects proposed or under development. One main project is Greater Gorgon, which will obtain gas from several large discoveries off Australia containing more than 40 tcf. Gorgon will have two 5-million tonne/year LNG trains and a domestic gas plant on Barrow Island.

The project also includes reinjection and sequestration of carbon dioxide on Barrow Island.

Final approval for the development is still pending. The project has obtained the go ahead from Western Australia's minister for the environment but awaits federal environmental approval. Once approved, Gorgan may start shipping LNG after 2010.

The Sunrise and Troubadour field projects off East Timor and Australia are on hold awaiting ratification of treaties between the two countries. The projects would involve development of about 8 tcf of gas that an expansion of the Bayu Udan LNG plant would process.

Ichthys is a large 9.5-tcf deepwater gas and condensate project off northwest Australia that may include a semisubmersible production with a flowline to shore connected to a new LNG liquefaction plant.

In Indonesia, several new fields will supply gas to existing and new LNG plants and power stations. The largest new LNG project is Tangguh, which will come on stream in 2009 and process gas from new fields in Papua Bintuni Bay.

Indonesia also has several oil developments. Banyu Urip field in the Cepu block on Java is the largest oil field discovered in Indonesia in many years. The field will go on stream after 2010, exporting oil from a floating storage vessel moored off Tuban in the Java Sea.

Another large project in Indonesia is the planned development of 40 tcf of gas in Natuna D-Alpha field, discovered several decades ago. Development was delayed partly because of the high carbon dioxide content of the gas that complicates production facilities. ExxonMobil Corp. and the government of Indonesia are in discussions related to the terms for proceeding with the project.

India has both onshore oil and gas discoveries as well as large, deepwater 12-tcf discoveries off the country's eastern coast. The offshore gas possibly will be produced through subsea-completed wells brought to shore with long flowlines.

Several new projects will develop additional fields off China in both the South China Sea and Bohai Bay.

The Kikeh projects off Sarawak will be Malaysia's first deepwater project to start producing. Operator Murphy Oil Corp. expects first oil from the project in second-half 2007.

Gas production is slated to begin from an onshore field in Bangladesh and fields off Myanmar.

Development of gas fields in the Southern Highlands of Papua New Guinea has encountered some delay after plans to lay a 3,000-km pipeline to Queensland, Australia, were dropped. Development of this gas may now include construction of an LNG liquefaction plant.

Western Europe

Two large projects off Norway will go on stream this year. The subsea completed wells at Snøhvit started filling the 143-km flowline at the end of May, and

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

LNG production will start later in the year.

Ormen Lange is the other large project that will come on stream in 2007. The produced gas, condensate, and water stream from subsea-completed wells will flow to shore through two 30 in., 120-km flowlines. First gas is expected in October 2007.

Norway also has numerous projects that will tie back subsea-completed wells to existing offshore facilities.

In Italy, the onshore Tempa Rossa project will develop an estimated 200 million bbl of heavy oil reserves.

Eastern Europe, FSU

Phased development of Tengiz field continues with the $6-billion second generation plant and sour-injection projects.Plans call for the projects starting up in 2007 and increasing crude production capacity in 2008 to 460,000-550,000 b/d from the current 300,000 b/d.

Also in Kazakhstan, the first phase of the 13-billion-bbl Kashagan field should start producing in 2010.

New pipeline projects in Russia will allow production of several of its stranded gas fields, with the 120-tcf Shtockman field in the Barents Sea being the largest. The first phase of Shtockman field may start producing gas in 2011 at a rate 2.1 bcfd. Subsequent phases may increase production to 8.7 bcfd in 2014-19.

Another large field under development is the 70-tcf Kovykta in eastern Russia. Gazprom has recently become operator of the field that will require new pipelines for moving the gas to potential users, such as in China.

Middle East

Iran has a several large projects slated for developing light to heavy oil, as well as continued phased development of the offshore South Pars gas field, an extension of Qatar's giant North field.

Iraq has considerable potential in adding oil production capacity, although the agreements for developing its resources have not been finalized. Table 1 lists some of the potential fields that might be developed. One project that is proceeding is DNO ASA's development of the Tawke field in the Kurdish area of Iraq near the border with Turkey.

Kuwait is continuing to redevelop several fields that will increase its production capacity by 450,000 bo/d in 2012.

In Oman, a steamflood will develop the estimated 1 billion bbl of heavy-oil resources in the Mukhaizna field.

Phased development of the 900-tcf North field off Qatar continues with additional LNG trains and a GTL plant, although ExxonMobil canceled its proposed GTL plant in the country.

Saudi Arabia expects its various projects to add more than 3 million bo/d of production capacity. Its largest development is the Khurais expansion that has a designed peak production capacity of 1.2 million bo/d.

ADCO in Abu Dhabi plans on expanding the production capacity in various fields by 560,000 b/d.

Africa

Several projects in Algeria will redevelop fields that have produced for many years including Rhounde El Baguel field, the largest oil field in Algeria, which went on stream in 1962. Sonatrach expects production from this redevelopment to peak at 100,000 bo/d in 2009.

New projects off Angola will add 1.8 million bo/d in production capacity. These projects mostly depend on floating production, storage, and offloading (FPSO) vessels and subsea wells for production.

A barge-based facility moored in deepwater off Congo (Brazzaville) will produce oil from the Moho and Bilondo field.

Gas production off Equatorial Guinea will increase after completion of an LNG liquefaction plant on Bioko Island.

An FPSO is slated to produce Olowi field in 100-m water off Gabon.

The first offshore project off Libya will transport gas to Italy.

Nigeria has several LNG projects on tap for monetizing primarily associated gas, some of which is gas that was flared. Development of deepwater resources also continues and will add about 1.4 million bo/d on new production capacity in the next few years.

Company names in Table 1

ADCO	Abu Dhabi Co.
Addax	Addax and Oryx Group
ADNOC	Abu Dhabi National Oil Co.
AED	AED Oil Ltd.
Anadarko	Anadarko Petroleum Corp.
Apache	Apache Corp.
Aramco	Saudi Arabian Oil Co.
ATP	ATP Oil & Gas Corp.
Avarasya	Avrasya Technology Engineering and Construction Inc.
AWE	Australian Worldwide Exploration Ltd.
Barrett	Barrett Resources LLC
BHP	BHP Billiton Ltd.
BlackRock	BlackRock Ventures Inc.
BP	BP PLC
Cairn	Cairn Energy PLC
Chevron	Chevron Corp.
CNOOC	China National Offshore Oil Corp. Ltd.
CNRL	Canadian Natural Resources Ltd.
Connacher	Connacher Oil and Gas Ltd.
ConocoPhillips	ConocoPhillips
Coogee	Coogee Resources Ltd.
Daewoo	Daewoo International Corp.
Devon	Devon Energy Corp.
DNO	DNO ASA
El Paso	El Paso Corp.
EnCana	EnCana Corp.
Eni	Eni SPA
ExxonMobil	ExxonMobil Corp.
First Calgary	First Calgary Petroleums Ltd.
Gazprom	OAO Gazprom
Helix	Helix Energy Solutions Group
Hess	Hess Corp.
Hunt Oil	Hunt Oil Co.
Husky	Husky Energy Inc.
Inpex	Inpex Holdings Inc.
Imperial Oil	Imperial Oil Ltd.
JACOS	Japan Canada Oil Sands Ltd.
KOC	Kuwait Oil Co.
KPC	Kuwait Petroleum Corp.
Lukoil	OAO Lukoil
Maersk	Maersk Group
Marathon	Marathon Oil Corp.
MEG Enegy	MEG Energy Corp.
Murphy	Murphy Oil Corp.
Nexen	Nexen Inc.
NIOC	National Iranian Oil Co.
Nippon	Nippon Oil Exploration Ltd.
Norsk Hydro	Norsk Hydro ASA
Occidental	Occidental Petroleum Corp.
OGI	OGI Group
Origin Energy	Origin Energy Ltd.
OMV	OMV AG
PDO	Petroleum Development Oman LLC
Pdvsa	Petroleos de Venezuela SA
Pemex	Petroleos Mexicanos
Pertamina	PT Pertamina (Persero)
Petrel	Petrel Resources PLC
Petrobras	Petroleo Brasileiro SA
PetroCanada	PetroCanada
PetroChina	PetroChina Co. Ltd.
Petrodar	Petrodar Operating Co.
Petrofac	Petrofac Group
Petrom	Petrom SA
Pioneer	Pioneer Natural Resources Inc.
PTTEP	PTT Exploration & Production PLC
Qeshm	Qeshm Energy Oil Industries Development Co.
QP	Qatar Petroleum Corp.
Reliance	Reliance Industries Ltd.
Repsol	Repsol YPF SA
Rosneft	OAO Rosneft
Santos	Santos Ltd.
Shell	Shell Group
Sinopec	Sinopec Corp.
Soco	Soco Internationa Ltd.
Sonangol	Sonangol
Sonatrach	Sonatrach
Statoil	Statoil ASA
Suncor	Suncor Energy Inc.
Syncrude	Syncrude Canada Ltd.
Synenco	Synenco Energy Inc.
Talisman	Talisman Energy Inc.
Toreador	Toreador Resources Corp.
Total	Total SA
Tullow	Tullow Oil PLC
Value Creation	Value Creation Inc.
Venture	Venture Production PLC
Woodside	Woodside Petroleum Ltd.

Western Hemisphere

The main operator off Brazil remains Petrobras, although several new projects will have other operators.

Petrobras continues the phased development of several giant fields in the Campos basin with subsea completed wells tied into floating production systems. The company also plans to develop large new gas and oil projects in the Santos and Espirito Santo basins.

In the next few years, units of El Paso Corp., Chevron Corp., Norsk Hydro ASA, and Devon Energy Corp. will join Shell Group as the only other companies, besides Petrobras, producing off Brazil.

If peak production occurred at the same time for all listed bitumen projects in Canada, Canada's production capacity would increase by 4.9 million b/d. These projects, however, are phased in and forecasts say that they will add about 2 million b/d by 2016 to the current 1.2 million b/d produced from the vast oil sands region in Alberta.

Methods for recovering the bitumen include mining and steam injection, such as steam-assisted gravity drainage (SAGD) or steam-and-soak methods.

Operators and the Canadian government have not reached a final agreement regarding the proposed $6-billion (Can.), 760-mile McKenzie Delta pipeline that would allow for producing the large stranded gas resources in the Northwest Territories. But negotiations still continue and some expect first gas to flow sometime after 2014.

BP continues developing new fields in its hub and spoke Cannonball project that provides gas for Atlantic LNG Train 4 in Trinidad. The fields have standardized normally unmanned platforms.

The Red Mango platform is one of BP's projects. Wells on the platform will produce a field discovered in 2000, and the produced gas will flow to the Cassia B hub. Wells on another platform, Cashima, will produce gas from both Cashima field, discovered in 2001, and North East Queen's Beach (NEQB) field, discovered in 1975. Gas from Cashima

will flow to the Amherstia hub.

Mexico has plans for boosting recovery through injection of nitrogen in several fields, including the onshore Jujo-Tecominacan field.

In Peru, further development of Camisea gas field includes construction of an LNG plant. Another project in Peru will redevelop an offshore gas field and deliver the gas to an onshore power plant.

The US Gulf of Mexico has many deepwater discoveries that will add substantial amounts on new production capacity. These projects include installation of semisubmersible production units, spars, tension-leg platforms (TLPs), and tie-backs of subsea completed wells.

The US Minerals Management Service (MMS) forecasts that oil production from the gulf may increase to 2.1 million b/d in 2016 from the 1.25 million b/d produced in 2006. Gas production may be 9.5 bcfd in 2016 compared with the 7.95 bcfd produced in 2006, according to the MMS forecast.

In 2007, the Independence Hub is slated to become operational. The hub will handle gas produced from 10 fields completed with subsea wells, some of which are in water deeper than 8,000 ft. The development has a designed production capacity of 1 bcfd.

Operators and the government of Alaska have not reached agreement on the construction of a $20 billion Alaska gas pipeline that would allow production of an estimated 40 tcf of gas currently stranded on the North Slope.

If an agreement is reached, gas may start flowing after 2012.

Technological advances in the US as well as higher gas prices have made many tight gas, shale gas, and coalbed gas developments feasible, such as the Piceance tight-gas projects in Colorado.

Venezuela has several large gas and heavy oil development projects planned, although recent actions by the Venezuelan government may cause a delay in their completion. ✦

MAJOR PROJECTS

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Algeria					
Block 208—EKT, EMK, EMN, EME	2010	155		Anadarko	$2 billion, oil and condensate
Berkine Block 405a—Menzel Ledjmet North (MLN)	2007	40		ConocoPhillips	Oil, 3 tcf gas
Berkine Block 405b	2009	40		First Calgary	Condensate
El Gassi, El Agreb, Zotti	2009	15		Hess	$500 million redevelopment
Skikda condensate splitter	2008	125		Sonatrach	$0.5 billion
Rhourde El Baguel	2009	100		Sonatrach	Redevelopment of one of Algeria's largest oil fields
Zarzaitine	2010	15		Sinopec	$500 million redevelopment
Angola					
Plutonio, Paladio, Platina, Galio, Cromio, and Cobalto	2007	200	330	BP	Block 18, FPSO spread-moored, 2 million bbl storage, 1,350-m water
Plutao, Saturna, Venus, Marte (PSVM)	2010+	150		BP	Block 31, 500 million bbl of oil, FPSO, 150,000 bbl storage, 5,900-6,730 ft water
Platino, Chumbo, Cesio	2010			BP	Block 18, FPSO, 1,600-m water
Benguela, Belize, Lobito, Tomboco	2008	200		Chevron	Block 14, Compliant tower in 396-m water, production started in late 2005 but will reach a peak after tie-in of subsea completed Lobito and Tomboco
Negage	2009	75	100	Chevron	Block 14, FPSO 1.5 million bbl storage, 1,500-m water
LNG various fields	2012	50	95	Chevron	Onshore, one train, 5 million tonnes/year
Tombua, Landana	2010	100	210	Chevron	Block 14, compliant tower in 400-m water
Kizomba C—Mondo	2008	100		ExxonMobil	Block 15, 600 boe from all three C fields, FPSO, 2 million bbl storage, 1,000 m water
Kizomba C—Saxi, Batuque	2008	100	300	ExxonMobil	Block 15, FPSO, 1.6 million bbl storage, 1,000 m water
Kizomba Satellites	2010+	125		ExxonMobil	Block 15, FPSO, 1,000-m water
Marimba North	2007	40		ExxonMobil	Block 15, subsea wells tied back to Kizomba A
Zenza	2007			Maersk	Block 17, FPSO
Gimboa	2008	60	20	Sonangol	Leased FPSO, 1.8 million bbl storage
Rosa	2007	140		Total	Block 17, subsea wells tied back 15 km to Girassol FPSO, production started June 2007
Cravo-Lirio-Orquidea-Violeta (CLOV)	2010+	150		Total	Block 17, FPSO
Pazflor—Perpetua, Zinia, Hortensia, Acacia	2010+	200		Total	Block 17, FPSO
Gindungo, Canela, Gengibre (GCG)	2010+	120		Total	Block 32, 300 million bbl of oil, FPSO, 4,600-5,900 ft water
Australia					
Puffin	2007	40	12	AED	FPSO, 70-m water
Pyrenees	2008+	100		BHP	FPSO, 1 million bbl storage, 200-m water
Stybarrow	2009	80		BHP	FPSO, 800 million bbl storage, 825-m water
Vincent	2008	120	100	BHP	FPSO, 360-m water
Gorgon, Jansz, Io, Chandon, Geryon, Maenad, Orthrus	2010+	10	1,575	Chevron	Greater Gorgon 2 million tonnes/year LNG trains on Barrow Island to development about 40 tcf of gas, subsea wells tied back to shore
Montara, Skua, Swift-Swallow	2008	40		Coogee	Platform, FPSO, subsea wells in 80-m water
Blacktip	2009		180	ENI	$325 million, Northwest shelf, platform in 50-m water and 108-km pipeline
Kipper, Tuna	2010+	20	150	ExxonMobil	Gippsland basin gas, Kipper includes initially two subsea completed wells tied back to West Tuna platform
Scarborough	2010+	965		ExxonMobil	10 tcf of gas
Ichthys	2012+	100	2,400	Inpex	Northwest shelf, semisubmersible in 230-m water, onshore LNG plant, 200-km flowline, 9.5-tcf gas, 312 million bbl condensate
Bass Gas Project—Yolla field	2007	17	46	Origin Energy	Fixed platform off Victoria, 400 bcf of reserves
Pluto	2010		800	Woodside	LNG, 4.1 tcf offshore, 5-6 million mt/year
Azerbaijan					
ACG Phase 2—East Azeri	2007	260		BP	Fixed platforms, production started yearend 2006
ACG Phase 3—Deepwater Gunashli	2008	260		BP	
Bangladesh					
Bibiyana	2010		500	Chevron	Onshore, production start in 2007
Brazil					
Frade	2011	100	20	Chevron	$2.8 billion, 200-300 million bbl, FPSO, 1.5 million bbl storage, 18-20° oil, 3,500-ft water, production start in 2009
Papa-Terra Modules 1 and 2	2011+			Chevron	1,200 m water, 14-17° gravity oil, 700-1,000 million bbl
Polvo	2007	50		Devon	Fixed platform, FPSO, 105-m water
Pinauma	2008	30		El Paso	$90 million, 50 million bbl of light oil in Camamu basin, off Brazil's northeastern Bahia state
Peregrino	2010	100		Norsk Hydro	$2.5 billion, 300-600 million bbl heavy oil, Campos basin, BM-C-007, leased FPSO, two fixed platforms, 30 horizontal producers, 7 water injection wells
Baleia Azul	2011+			Petrobras	Northern Campos basin
Cachalote and Baleia Franca	2011+			Petrobras	Espirito Santo basin, heavy 19° oil, 1,400 m water
Espadarte Module 2	2007	100	2.5	Petrobras	FPSO, Rio de Janeiro, turret-moored, leased, 1.6 million bbl storage, 20-22° oil, 1,240-m water
ESS-164	2008		210	Petrobras	Gas in Espirito Santo basin
Golfinho Module 2 (ESS-132)	2007	100	125	Petrobras	FPSO, Cidade de Vitoria, 1.8 million bbl storage, 28° oil, Espirito Santo basin
Golfinho Module 3 (ESS-130)	2008	100	100	Petrobras	
Jubarte Phase 2 P-57	2010	180	20	Petrobras	FPSO, 1,8 million bbl storage, 1,250-m water, 17° oil
Marlim Leste P-53	2009	180		Petrobras	FPSO, turret-moored, 1,080-m water, 15-27° oil
Marlim Sul P-51	2008	180	210	Petrobras	Semisubmersible spread-moored, 28° oil, 1,255-m water

MAJOR PROJECTS—(CONTINUED)

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Marlim Sul P-56	2011+	100		Petrobras	Floating vessel
Plangas expansions	2008+		850	Petrobras	Canapu and Carupin fields, gas plant expansions
Bahia, Manati	2007		200	Petrobras	Shallow water, Camamu-Almeda basin
Marlim Sul Module 4	2011+			Petrobras	
Mexilhao	2009	20	600	Petrobras	Fixed platform, 172-m water, FPSO
RJS633	2010			Petrobras	
Roncador P-52	2008	180	330	Petrobras	Semisubmersible spread-moored, 29° oil, 1,850-m water
Roncador P-54	2007	180	210	Petrobras	FPSO spread-moored, 1,315-m water, 2 million bbl storage, 17° oil
Roncador P-55	2011	180	20	Petrobras	Semisubmersible, 22° oil
Roncador Module 4	2011+			Petrobras	
SPS25	2009			Petrobras	Gas
Parque das Conchas—Abalone, Argonauta, Nautilus, Ostra	2011+	100		Shell	BC-10, FPSO, 1,500-2,000 m water
Canada					
Orion Hilda Lake Phase 1	2007	10		Shell	SAGD, $225 million (Can.)
Orion Hilda Lake Phase 2	2009	10		Shell	SAGD $115 million (Can.) expansion
Hebron	2010+	140		Chevron	$5 billion offshore heavy oil, suspended project, 300 km off Newfoundland in North Atlantic
Birch Mountain Phase 1	2013	30		CNRL	SAGD
Birch Mountain Phase 2	2015	30		CNRL	SAGD
Gregoire Lake Phase 1	2016	30		CNRL	SAGD
Gregoire Lake Phase 2	2018	30		CNRL	SAGD
Gregoire Lake Phase 3	2020	30		CNRL	SAGD
Gregoire Lake Phase 4	2023	30		CNRL	SAGD
Horizon Phase 1	2008	135		CNRL	Mine and upgrader, 6 billion bbl resource, 500,000 b/d in 2017
Horizon Phase 2	2011	45		CNRL	Mine and upgrader
Horizon Phase 3	2011	90		CNRL	Mine and upgrader
Horizon Phase 4	2015	145		CNRL	Mine and upgrader
Horizon Phase 5	2017	162		CNRL	Mine and upgrader
Kirby Phase 1	2011	30		CNRL	
Primrose East	2009	30		CNRL	Cyclic steam, Primrose upgrader Phase 1, 2012, 145,000 b/d, Phase 2, 2019, 58,000 b/d
Great Divide	2008	10		Connacher	SAGD, 60 million bbl
Parsons Lake	2014+			ConocoPhillips	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd MacKenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields
Surmont Phase 1	2007	25		ConocoPhillips	SAGD, $1.1 billion (Can.) four-phase project with initial project starting in 2007
Surmont Phase 2	2008	25		ConocoPhillips	
Surmont Phase 3	2011	25		ConocoPhillips	
Surmont Phase 4	2014	25		ConocoPhillips	
Jackfish Phase 1	2008	35		Devon	SAGD, $450 million (Can.)
Jackfish Phase 2	2009	35		Devon	SAGD, $500 million (Can.)
Borealis Phase 1	2010	100		EnCana	SAGD
Borealis Phase 2	2011	25		EnCana	SAGD
Borealis Phase 3	2012	25		EnCana	SAGD
Borealis Phase 4	2013	25		EnCana	SAGD
Borealis Phase 5	2014	25		EnCana	SAGD
Christina Lake Phase 1B	2008	30		EnCana	SAGD
Christina Lake Phase 1C	2009	30		EnCana	SAGD
Christina Lake Phase 1D	2010	30		EnCana	SAGD
Christina Lake expansion 1	2011	30		EnCana	SAGD
Christina Lake expansion 2	2012	30		EnCana	SAGD
Christina Lake expansion 3	2013	30		EnCana	SAGD
Christina Lake expansion 4	2014	30		EnCana	SAGD
Christina Lake expansion 5	2015	30		EnCana	SAGD
Foster Creek Expansion 1	2009	25		EnCana	SAGD, $440 million (Can.)
Foster Creek Expansion 2	2011	25		EnCana	SAGD
Kearl Phase 1	2010+	100		ExxonMobil	Mine
Kearl future phases	2010+	200		ExxonMobil	Mine
Mackenzie gas project	2010+	10	830	ExxonMobil	
Sunrise Phase 1	2009	50		Husky	SAGD, 40-year phased project with expected recovery of 3.2 billion bbl
Sunrise Phase 2	2010	50		Husky	SAGD
Sunrise Phase 3	2012	50		Husky	SAGD
Sunrise Phase 4	2014	50		Husky	SAGD
Cold Lake Phases 14-16, Nabiye, Mahihkan North expansion	2007	30		Imperial Oil	Cyclic steam
Taglu	2014+			Imperial Oil	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd MacKenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields
Hangingstone Phase 1	2010+	25		JACOS	SAGD, pilot on production
Hangingstone Phase 2	2012+	25		JACOS	SAGD
Christina Lake	2010+	95		MEG Energy	SAGD, 3,000 b/d pilot approved, 2 billion bbl estimated recoverable
Long Lake Phase 1	2007	72		Nexen	SAGD with onsite upgrader, $3.5 billion, 40-year project with 2.6 billion bbl recovery
Long Lake Phase 2	2010	72		Nexen	SAGD
Long Lake Phase 3	2012	72		Nexen	SAGD
Long Lake Phase 4	2014	72		Nexen	SAGD
Card Phase 1	2010+	4		PetroCanada	SAGD

MAJOR PROJECTS—(CONTINUED)

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Fort Hills Phase 1	2011	160		PetroCanada	$14.1 billion (Can.) mine, upgrader, 2.8 billion bbl
Fort Hills Phase 2	2015	160		PetroCanada	$12.1 billion (Can.) mine, upgrader
Lewis Phase 1	2010+	40		PetroCanada	SAGD, 3 billion bbl
Lewis Phase 2	2010+	40		PetroCanada	SAGD
MacKay River expansion	2009+	40		PetroCanada	$1 billion (Can.) SAGD
Meadow Creek Phase 1	2010+	40		PetroCanada	SAGD, $800 million (Can.), 1.3 billion bbl
Meadow Creek Phase 2	2010+	40		PetroCanada	
Carmon Creek Phase 1	2009	18		Shell	Cyclic steam
Carmon Creek Phase 1 expansion	2012	35		Shell	Cyclic steam
Carmon Creek Phase 2	2012	35		Shell	Cyclic steam
Muskeg mine debottlenecking	2010	115		Shell	Albian Oil Sands project, with Scotford upgrader expansion of 135,000 b/d by 2009
Jackpot mine Phase 1	2010	100		Shell	Albian Oil Sands project
Jackpot mine Phase 2	2012	100		Shell	Albian Oil Sands project
Jackpot mine Phase 3	2014	100		Shell	Albian Oil Sands project
Niglintgak	2014+			Shell	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd MacKenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields
Kai Kos Dehseh Phase 1 (Leismer)	2009	10		Statoil	SAGD pilot
Kai Kos Dehseh Phase 2	2010	30		Statoil	SAGD with upgrader
Kai Kos Dehseh Phase 3	2011	40		Statoil	SAGD with upgrader
Kai Kos Dehseh Phase 4	2012	40		Statoil	SAGD with upgrader
Kai Kos Dehseh Phase 5	2015	40		Statoil	SAGD with upgrader
Firebag Phase 3	2008	35		Suncor	SAGD
Firebag Phase 4	2009	35		Suncor	SAGD
Firebag Phase 5	2012	50		Suncor	SAGD
Firebag Phase 6	2013	50		Suncor	SAGD
Firebag Phase 7	2014	50		Suncor	SAGD
Firebag Phase 8	2015	60		Suncor	SAGD
Steepbank mine and upgrader expansions Voyageur project	2010+	250		Suncor	$6 billion (Can.), mine, $350 million (Can.), upgrader $2.1 billion (Can.)
Syncrude expansion Stage 3	2011	43		Syncrude	Mine and processing
Syncrude Stage 4	2015	140		Syncrude	Mine and processing
Northernlights Phase 1	2010	50		Synenco	Mine and upgrader, recover 1 billion bbl over 28 years
Northernlights Phase 2	2012	50		Synenco	Mine and upgrader
Joslyn Phase 3A	2009	15		Total	SAGD
Joslyn Phase 3B	2011	15		Total	SAGD
Joslyn Mine Phase1	2010+	50		Total	Mine and upgrader, 100 b/d upgrader
Joslyn Mine Phase 2	2013	50		Total	
Joslyn Mine Phase 3	2016	50		Total	
Joslyn Mine Phase 4	2019	50		Total	
Halfway Creek Phase 1	2009	10		Value Creation	SAGD pilot
North Joslyn Phase 1	2009+	40		Value Creation	SAGD
China					
Wenchang	2007	120		CNOOC	FPSO, 135-m water
Xijiang 23-1	2007	100		CNOOC	FPSO, 90-m water
Peng Lai	2008	190		ConocoPhillips	Bohai Bay, well platforms and FPSO turret moored, 2 million bbl storage, 30-m water. 800 million bbl of oil
Liwan	2012+		500	Husky	South China Sea gas, deep water
Nanpu	2012+	200		PetroChina	Bohai basin
Puguang	2008		390	Sinopec	9 tcf gas, Sichuan province, southwestern China
Puguang expansion	2010		390	Sinopec	
Tahe expansion	2009+			Sinopec	1 billion bbl oil
Colombia					
La Cira-Infantas redevelopment	2010	20		Occidental	New wells, waterflooding, steam, gas injection, horizontal drilling
Congo (Brazzaville)					
Mer Tres Profonde South, North	2009			Murphy	FPSO, 700,000 bbl storage, 1370-m water, 400 boe discoveries made in 2006
Moho and Bilondo	2008	80	45	Total	12 subsea wells tied back to a barge-based floating production unit in 800-m of water
Denmark					
Elly, Adda	2009		75	Maersk	
East Timor					
Sunrise and Troubadour fields	2010+			Woodside	$7 billion (Aus.), 8 tcf of gas, and 300 million bbl of condensate, 90-550 m of water, tied into Bayu Undan LNG expansion
Egypt					
Saqqara	2008			BP	Gulf of Suez, gas, 9-slot platform
Equatorial Guinea					
Okume Complex	2007	60		Hess	$1.1 billion, Northern Block G fields, two TLPs 500-m water, four fixed platforms in 50-60-m water, Okume, Oveng, Ebano, and Elon fields
LNG liquefaction plant at Punta Europa, Bioko Island	2008		500	Marathon	$1.4 billion LNG plant to liquefy 3.4 million tonnes/year of Alba field gas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MAJOR PROJECTS—(CONTINUED)

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Gabon					
Olowi	2008	25	85	CNRL	FPSO spread moored, 1.3 million bbl storage, 100-m water
India					
Aishwariya	2008+	10		Cairn	Onshore, 29-32° oil
Mangala	2007	80		Cairn	Onshore, 22-29° oil
Bhagyama	2008+	20		Cairn	Onshore, 21-30° Oil
Raageshwari and Saraswati	2008+			Cairn	Onshore, 32-42° oil
Dhirubhai field, Krishna-Godavari Block D6	2009+		2,800	Reliance	$5.2 billion, 12 tcf; 40-60 km southeast of Kakinada, 400-2,700-m water
MA	2008	60	100	Reliance	FPSO, 1,000-m water
Indonesia					
Tangguh LNG liquefaction project	2009		1,400	BP	$2.2 billion project, 7 million tonnes/year of gas from Papua Bintuni Bay fields, 225-ft water
Kerisi	2007			Chevron	South Natuna Block B oil
Banka, Gendalo, Gehem	2013			Chevron	Kutei basin, deepwater gas
Sadewa	2010			Chevron	Kutei basin gas
Kerisi-Hiu	2008			ConocoPhillips	Tied into Belanak, 59,000 boe/d
North Belut	2009+			ConocoPhillips	Tied into Belanak, 54,000 boe/d
Banyu Urip	2010+	165	20	ExxonMobil	$2.6 billion, Cepu block, onshore Java, 50 wells drilled from four wellpads, 60-mile pipeline to 2 million bbl FSO moored off Tuban
Natuna D-Alpha	2010+		1,100	ExxonMobil	46 tcf of gas, 70% carbon dioxide, South China Sea
Ujung Pankah	2007		440	Hess	Gas for power plant at Gresik near Surabaya in East Java
Singa	2008		50	Medco	Lematang block, south Sumatra, gas for Sumatra-Java pipeline Phase 1 local markets
Senora				Medco	Gas for poposed LNG plant, 2.4 tcf with Matindok
Matindok				Pertamina	Gas for poposed LNG plant
Podok Tengah	2007	12		Pertamina	Onshore Java, production started Aug. 2005 at 4,000 bo/d
Jeruk	2008+			Santos	50 million bbl oil discovery off Madura island, project downgraded and under reevaluation
Oyong oil	2007	20		Santos	FSO and production barge in 120-ft water off East Java
Oyong gas	2008		60	Santos	
Sisi-Nubi	2007			Total	Offshore Kalimantan gas for LNG
Tunu Phases 10 and 11				Total	Kalimantan gas for LNG
Tambora field extension				Total	Kalimantan gas for LNG
Iran					
Darkhovin, Masjid, and Suleiman fields	2007	110		Eni	Light oil
Azadegan North Phase 2	2012	110		NIOC	Heavy oil
Azadegan South	2009	125		NIOC	$3 billion, heavy oil
Kushk-Hosseinieh	2009	300		NIOC	Heavy oil
South Pars oil—Ahwaz field	2007	255		NIOC	Medium oil
South Pars Phases 9 and 10	2009	80		NIOC	$1.9 billion, condensate, gas
Yadavaran	2011	300		NIOC	Medium oil
Azar				Norsk Hydro	Anaran Block, Western Iran, 2 billion bbl in carbonates
Rag e Safid-Bangestan redevelopment	2007	150		Qeshm	Light oil
South Pars Phases 6, 7, 8	2007	120	2,600	Statoil	$1 billion, condensate, gas
Salman, Foroozan, Dorood field redevelopment	2007	150		Total	Medium oil
Iraq					
Subba-Luhais expansion	2008	100			2 billion bbl, southern Iraq
West Qurna expansion	2010+	600			11-15 billion bbl, west of Basra
Khurmala	2008+	70			Near Kirkuk
Hamrin	2008+	60			Southwest of Kirkuk
Majnoon	2008+	500			11-30 billion bbl, 28-35° API, 30 miles north of Basra
Al-Ahdab	2008+	90			Southern Iraq
Tawke	2007			DNO	100 million bbl, near Turkish border, in Kurdish region
Chemchamal, Jaria Pika, Khashm al Ahmar, and Mansuriya	2008				10 tcf gas fields
Ireland					
Corrib	2008		320	Shell	Subsea wells in 350-m water tied back to shore with 83 km, 20-in. flowline
Italy					
Tempa Rossa	2010+	50	20	Total	$700 million, 200 million bbl of heavy oil
Kazakhstan					
Tengiz-Phase 1	2008	285	290	Chevron	$5.5 billion expansion and sour gas injection project
Tengiz expansion	2010+	260		Chevron	$9.5 billion expansions to develop 3.3 billion bbl of oil with Phase 1
Kashagan Phase 1	2010+	450		Eni	$29 billion, 13 billion bbl of oil, production start in 2008, 1.2 million bo/d from all phases
Kashagan future phases	2010+	1,000		Eni	
Vladimir Filanovsky	2009+	100		Lukoil	Caspian Sea, 600 million bbl of oil and 1.2 tcf of gas
Komsomolskoe	2010	10		Petrom	Onshore $190 million project
Kuwait					
Sabriya	2007	50		KOC	Light oil
Kuwait North redevelopment	2012	450		KPC	
B140/B150	2007			KPC	$7-9 billion, medium oil

MAJOR PROJECTS—(CONTINUED)

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Libya					
Onshore Wafa-NC 175 and offshore Bahr Essalam	2007		350	Eni	Gas via Greenstream pipeline to Italy, Sabratha fixed offshore platform
Al-Jurf	2007	40		NOC	Oil
Amal	2008	40		NOC	Oil
Malaysia					
Jernah B	2008		150		
Gumusut-Kakap	2011	150		Shell	Semisubmersible, 1,000-m water
Kikeh	2007	120		Murphy	Spar and FPSO turret-moored, 1.5 million bbl storage, 1,330-m water
Cendor	2007	12		Petrofac	Jack up and FSO, 60-m water
SK8	2010+	90		Shell	
PM-3 CAA Northern fields	2008+	40	270	Talisman	Oil and gas reserves
Mauritania					
Tiof	2008	75		Woodside	FPSO
Mexico					
Jujo-Tecominoacan	2007+			Pemex	Nitrogen injection
Myanmar					
Shwe, Shwe Phyu, Mya	2009+			Daewoo	4.8-8.6 tcf recoverable
Namibia					
Kudu	2012			Tullow	Offshore, 170-m water, 4 tcf gas reserves, initial for power plants, later for possible 5 million/tons/year LNG train
Netherlands					
K5	2007		90	Total	Subsea development tied back to existing K6N platform
Waddenzee	2007		195		
New Zealand					
Tui, Amokura, Pateke	2007	50	25	AWE	$260 million, initial 4 subsea wells connected to FPSO, 27.5 miilion bbl recoverable oil, 120-m water
Kupe	2009	7	60	Origin Energy	$980 million (NZ), 400 bcf, gas, NGL, condensate offshore in Taranaki basin, 35-m water, wellhead platform with six wells
Maari	2008	40		OMV	FPSO, 100-m water
Nigeria					
Oron	2007	50		Addax	Fixed platforms, 70-km off Niger Delta in 8-m water
Agbami	2008	250	450	Chevron	$5.2 billion, FPSO, 2.3 million bbl storage, 1,460-m water
Nsiko	2012+	100		Chevron	OPL 249
Olokola LNG	2010	`		Chevron	$7 billion first stage to produce 11 million tonnes/year of LNG
Brass LNG	2010		1,300	Eni	$7 billion, two trains LNG associated gas and gas from OML 60 and 61 gas fields
Bosi	2010+	135		ExxonMobil	$2 billion, FPSO, 2 million bbl storage, 1,700-m water
East Area NGL II	2008	40		ExxonMobil	
LNG IPP Project	2010+		700	ExxonMobil	
Satellite projects	2010+	125		ExxonMobil	
Bonga Ullage	2009+	70	50	Shell	Oil deepwater
Bonga North, Northwest	2010+	150	80	Shell	FPSO in 4,000-ft water
Bonga Southwest	2010+	140	105	Shell	FPSO
Akpo	2008	175	320	Total	$2.3 billion, OML 130, FPSO 2 million bbl storage, 1,314-m water, gas to Bonny NLNG, 620 million bbl of 53° gravity condensate, 1 tcf gas, 44 subsea wells
Ofon 2	2009		400	Total	OML 102 gas for LNG
Usan	2011+	180		Total	FPSO
Ukot, Togo	2010	0		Total	$4 billion, FPSO in 2,600-ft water
Norway					
Skarv-Idun	2010+	39	580	BP	Skarv FPSO oil and gas development, Idun subsea tie-back to Skarv in 390-m water
Valhall redevelopment	2010	150	175	BP	New platform
Goliat	2008+			Eni	250 million bbl field in Barents Sea, 380-m water
Njord gas	2007	15	185	ExxonMobil	Gas export from oil field on stream in 1997
Freja	2008+			Hess	70-m water, subsea wells tied in to existing infrastructure
Alvheim	2007	85		Marathon	9.1 billion Norway krone, FPSO, turret-moored, 0.6 million bbl storage, 125-m water
Ormen Lange	2007	35	2,385	Norsk Hydro	33 billion Norway krone ($10 billion), 120 km subsea to shore tie-back, 14 tcf of reserves,
Vilje	2007			Norsk Hydro	2.4 biilion Norway krone, 2 subsea wells tied into Alvheim field, 50 million bbl of oil,
Trym	2008+			Shell	Gas and condensate tied in to Harald field off Denmark
Dagny	2008+			Statoil	Subsea completions tied in to Sleipner
Gjoa	2010	35	360	Statoil	60 million bbl of oil, 35 bcf gas, semisubmersible, 360 m water
Snohvit	2007		800	Statoil	8 billion Norway krone, 7 tcf, LNG, subsea wells tied back to shore
Statfjord late life	2007	70	360	Statoil	Depressurization of the Brent reservoir
Tyrihans	2009	80	330	Statoil	$2.2 billion, 460 million boe, two subsea completed fields tied into Kristin semisubmersible platform
Valemon	2008+	50	30	Statoil	Subsea wells tied in to Kvitebjorn

MAJOR PROJECTS—(CONTINUED)

Table 1

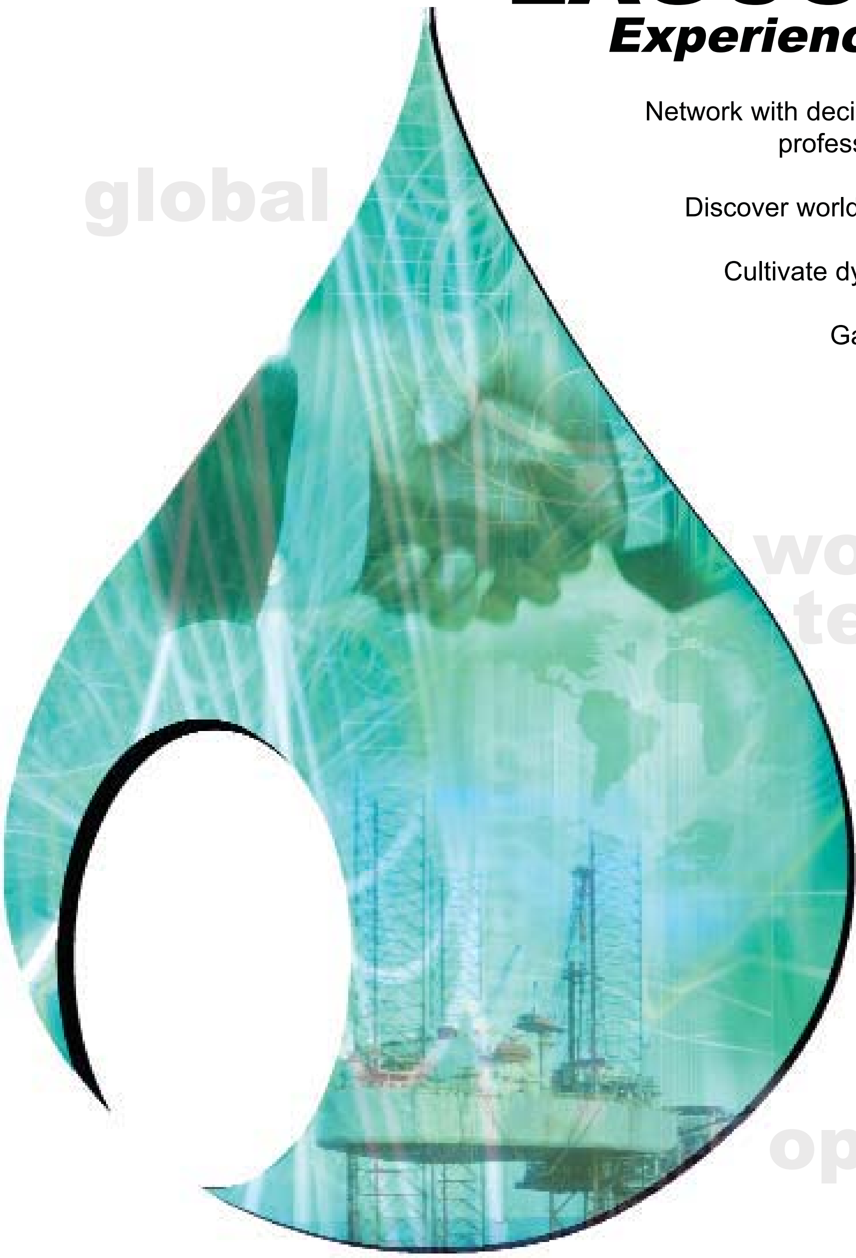
Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Volve	2007	55	15	Statoil	2.3 billion Norway krone, jack up and FSO, 90-m water, 70 million bbl oil and 1.5 billion cu m gas.
Blane	2007	14		Talisman	0.4 billion Norway krone, subsea development in 70-m water connected to Ula field
Enoch	2007	12		Talisman	0.2 billion Norway krone, subsea development in 70-m water connected to UK Brae field
Oman					
Mukhaizna steamflood	2008+	150		Occidental	Block 53, 16-18° oil, 1 billion bbl potential with steam
Harweel Phase 2, Harweel, Zalzala, Rabab, and other fields	2008	60	70	PDO	$1 billion, facilities and gas injection in oil fields in southern Oman
Papua New Guinea					
PNG gas	2010+	20	570	ExxonMobil	Gas from field in Southern Highlands, development options under study
Peru					
Corvina	2008+		40	BPZ	Refurbished offshore platforms, gas to power
Camisea gas/Peru LNG SRL	2009		1,300	Hunt Oil	Blocks 56 and 88, 700-km gas pipeline, 575-km liquids pipeline
Block 67	2010	100		Barrett	Three fields, 12-21° gravity oil, 248 mile pipeline
Qatar					
Al Rayyan	2008	50		Anadarko	0.2 billion oil
Al Khaleej gas Phase 2	2009	70	1,140	ExxonMobil	$1 billion, gas to local markets
Barzan Phase 1	2010+	135	1,500	ExxonMobil	1.5 bcfd for local markets
Qatargas 2 Train 4	2008	80	1,250	ExxonMobil	7.8 million tons/year
Qatargas 2 Train 5	2009	80	1,250	ExxonMobil	7.8 million tons/year
RasGas Train 5	2007	80	1,250	ExxonMobil	4.7 million tons/year
RasGas Train 6	2008	75	1,250	ExxonMobil	7.8 million tons/year
RasGas Train 7	2009	75	1,250	ExxonMobil	7.8 million tons/year
Al-Shaheen expansion	2009	285		Maersk	$3 billion
Idd al Shargi North and South Dome	2007	65		Occidental	$0.7 billion, oil
Maydan Mazham	2008	15		QP	$0.3 billion, oil
Pearl GTL	2009+	133		Shell	$7 billion
Russia					
Uran, Ust-Tegus	2008+			BP	First fields in UVAT project with 450 million bbl oil discovered and 1 billion bbl potential
Verkhnechnonskoye	2015+	100		BP	1 billion bbl resource
Sakhalin-1	2007	250		ExxonMobil	Started production in 2005 and reached peak production in Feb. 2007
Sakhalin-1 Future Phases	2010+		800	ExxonMobil	Gas pipeline from offshore 17-tcf Chayvo, Odoptu, and Arkutun-Dagi
Kovykta	2015+		2,500	Gasprom	70 tcf, awaiting pipelines for regional sales and sales to China
Sakhalin-2	2008	50	1,356	Gazprom	$20 billion, three platforms off Sakhalin for oil and gas fields with 4.5 billion boe reserves, LNG
Prirazlomnoye	2009+	150		Gazprom	560 million bbl reserves in Pechora Bay 35 miles offshore, 60 ft water
Shtokman	2011+		2,100	Gazprom	130 tcf, Barents Sea
Shtokman additional phases	2019		6,600	Gazprom	
Yuzhno-Russkoye	2010		3,900	Gazprom	21 tcf, involves completing a pipeline to Germany, first production in 2008
Yuzhno-Russkoye	2013			Gazprom	2nd pipeline to Germany completed
Khvalynskoye	2011		1,000	Lukoil	Caspian Sea, Russian sector, 12 tcf gas, 265 million bbl oil, and 148 million bbl NGL, production start in 2009
Vankor	2013+	120		Rosneft	900 million bbl; Krasnoyarsk Kray, western East Siberia
West Salym, Western Siberia	2013	143		Shell	Started production in late 2004
Saudi Arabia					
Abu Hadriya, Fadhili, and Khursaniya (AFK)	2007	500	1,000	Aramco	$2.2 billion, Arab light from fields discovered in 1940-56 and shut in 1980s
Karan			1,000	Aramco	Offshore Khuff gas field
Khursaniyah NGL	2007	80		Aramco	$1.9 billion, NGL, process gas from AFK development, and northern area fields
Nuayyim expansion	2008	100		Aramco	$0.4 billion, light oil
Shaybah Expansion 1	2008	250		Aramco	$1.4 billion, extra light
Shaybah Expansion 2	2008+	250		Aramco	
Hawiyah NGL, ethane	2008	370		Aramco	$3 billion, NGL
Khurais expansion, Abu Jifan, Mazalij	2009	1,200		Aramco	$8 billion, light oil
Manifa	2010+	900		Aramco	$1.0 billion, Arab heavy
Nuayyim	2008	100		Aramco	Light oil
Dammam	2010+	1,000		Aramco	
Sudan					
Melut basin Blocks 3 and 7, Palogue, Adar-Yale, Agordeed	2007	300		Petrodar	$1.9 billion, 1,349-km, 32-in.pipeline, expansions may increase production to 500,000 bo/d, production start in 2006 at 150,000 bo/d
Thailand					
Arthit	2008	10	150	PTTEP	FPSO, 80-m water, six wellhead platforms

MAJOR PROJECTS—(CONTINUED)

Table 1

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Trinidad					
Red Mango	2007		1,000	BP	3 tcf, nine-slot well protector platform, 26-in. pipeline to Cessia B hub
Cashima, North East Queen's Beach	2008		750	BP	Nine-slot well protector platform and 26-in. pipeline to Amherstia hub
Turkey					
Akkaya, Dogu, Ayazli	2007		100	Toreador	Production platforms
UAE					
ADCO expansions	2012	560		ADCO	
Upper Zakum redevelopment	2008	250		ExxonMobil	$2 billion, light oil
UK					
Alder	2011	9	80	Chevron	West of Britannia field
Ettrick	2008	30	35	Nexen	UK Blocks 20/2a and 20/3a, leased Aoka Mizu FPSO
Buzzard	2007	200		Nexen	Fixed platforms in Outer Moray Firth, Blocks 19/10, 20/6, 19/5a, and 20/1S, 100-m water
Chestnut	2007	30		Venture	Cylindrical FPSO spread-moored, leased, 0.3 million bbl storage, 120-m water
Starling	2008	5	120		
Tweedsmuir	2007	0		Talisman	$700 million, subsea wells tied back 55 km to Piper B platform
US					
Independence Hub	2007	5	1,000	Anadarko	Multifield development of Spiderman, San Jacinto, Atlas NW, Atlas, Mondo NW, Cheyenne, Jubilee, Vortex, Merganser, and Q fields in 8,000-ft water
Telemark	2008	20	60	ATP	Spar in 1,310-m water
Neptune	2007	50	50	BHP	$850 million, Atwater Valley blocks, TLP in 4,250-ft water, 100-150 million boe
Shenzi	2009+	100	50	BHP	$4.4 billion,Green Canyon Block 653, TLP in 4,400-ft water, 350-400 million boe
Thunder Horse	2008	210	185	BP	Semisubmersible in 6,050-ft water on Mississippi Canyon Block 778
Atlantis	2007	200	180	BP	Semisubmersible spread-moored, 1,650-m water, 20 wells, Green Canyon blocks
Orion Phase 2	2008	55		BP	Alaska heavy oil in Prudhoe Bay Unit, Schrader Bluff formation
San Juan CBM	2011			BP	$2 billion in next 13 years to develop 2.7 tcf
Wamsutter tight gas	2010		250	BP	$15 billion during next 15 years developing 450 million boe
Bigfoot	2011			Chevron	1,600-m water
Tahiti	2008+	125	70	Chevron	$3.5 billion, truss spar, 1,220-m water
Blind Faith	2008	40	35	Chevron	$900 million, Mississippi Canyon Blocks 695-696, semisubmersible in 6,500 ft water
Jack	2012			Chevron	2,100-m water
Cascade, Chinook	2009+			Petrobras	FPSO, Walker Ridge Blocks, 8,300-ft water
Piceance tight gas Phase 1	2008		200	ExxonMobil	Colorado
Piceance tight gas future phases	2010+	10	870	ExxonMobil	Colorado
Phoenix	2008	45	70	Helix	FPU, to restore production from Typhoon field
Thunder Hawk	2008	460	70	Murphy	Semisubmersible, 5,700-ft water
Oooguruk	2007	20		Pioneer	$500 million project on gravel island built in 4-ft water off Alaska North Slope in the Beaufort Sea
Perdido, Great White, Tobago, Silvertip	2010	100	200	Shell	Spar hub, 2,440-m water
Alaska Gas/Point Thomson	2012+	70	4,500	ExxonMobil	Awaiting the $20 billion, 3,400-mile, 4.6-bcfd Alaskan pipeline
Uzbekistan					
Kandym-Khauzak-Shady-Kungrad	2007		960	Lukoil	$100 million, 7 tcf of gas
Venezuela					
Loran				Chevron	5 tcf of gas
Carabobo 1	2012+	200		Pdvsa	9 billion bbl of heavy oil
Corocoro	2009	70		Pdvsa	West Paria Gulf
San Cristobal	2008+	400		Pdvsa	Block 2, Manatee area, 6 tcf LNG project
Deltana	2010+			Pdvsa	38 tcf off Venezuela and 21 tcf off Trinidad and Tobago
Mariscal Sucre	2008		600	Pdvsa	Offshore gas
Mariscal Sucre expansion	2011		600	Pdvsa	Offshore gas
Vietnam					
Vietnam gas project	2015		500	Chevron	$3.5 billion, Blocks B, 48/95, 52/97, production start in 2011
Su Tu Vang	2008	100		ConocoPhillips	
Phuong Dong	2008	20		Nippon	Block 15.2
Ca Ngu Vang	2008	20	450	Soco	Block 9-2
Yemen					
Marib (Block 18)	2008+		1,000	Total	$2 billion, LNG two trains 6.7 million tonnes/year, 9 tcf

Note: This table to be archived at www.ogjonline.com and updated periodically; please email project information to news@ogjonline.com



DRILLING MARKET FOCUS

Coiled tubing market grows steadily, attracts new players

Nina M.Rach
Drilling Editor

Drilling

Coiled tubing is one of the fastest growing oilfield technologies. CT services expanded 140% over 2001-06, second only to directional drilling, according to Colorado-based Spears & Assoc. Inc. (Table 1).[1]

Spears publishes an annual oil field market report that covers 33 market segments, among which are CT services, oil country tubular goods (OCTG), and unit manufacturing (includes CT).

Operators worldwide employ versatile coiled tubing; it plays many roles in drilling, well stimulation, completion, and workovers. It's also used for velocity and production strings, to convey logging tools, and for other special applications.

The CT market broadly includes equipment manufacturing, tubing string production, and CT services, including drilling. Coiled-tubing drilling (CTD) comprises only about 15% of the CT services industry but is growing more quickly than other areas.[2]

TOP FIVE OIL FIELD TECHNOLOGIES, 2001-06 — Table 1

	Growth, %
Directional drilling	142
Coiled tubing services	140
Pressure pumping	138
Completion equipment	114
LWD	105

Data from Spears & Associates Inc.

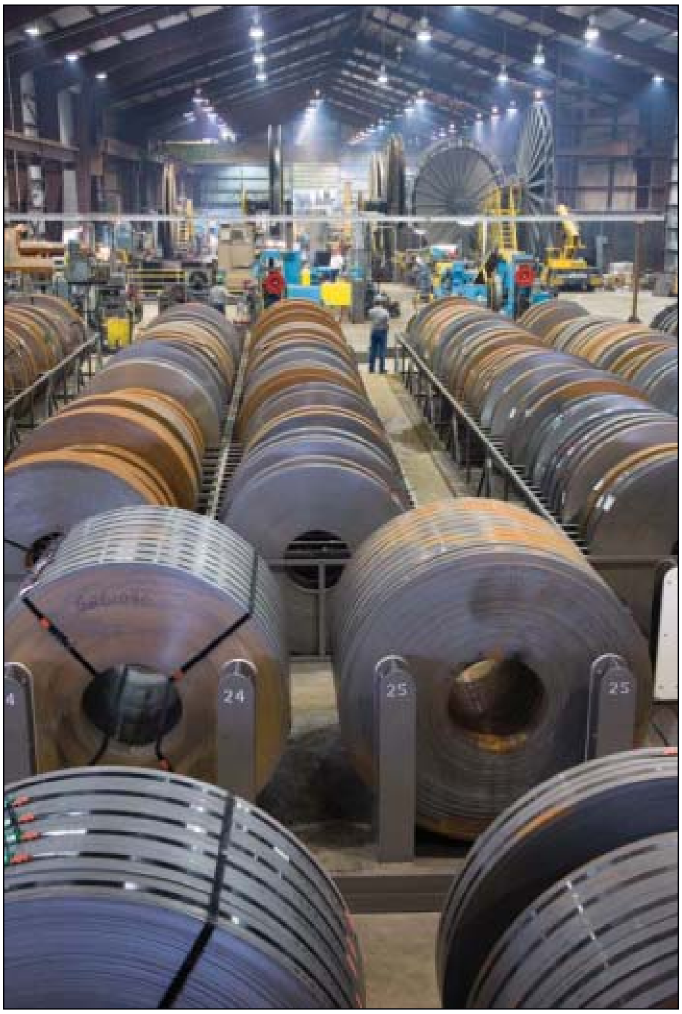
HydraRig's Randal Graves told OGJ the global market for CT (tubing, equipment, services) is probably $500-600 million/year.

National Oilwell Varco Inc. (NOV) controls about 70% of the global coiled-tubing equipment and tubing market through its subsidiaries HydraRig, Quality Tubing Inc., and recently acquired FIDmash, according to FIDmash's Leonid Gruzdilovich.[3]

Most of the world's CT units and tubing strings are made in the US, but the supply is supplemented by a few small, regional companies.

Market—tubing

Coiled tubing is produced by seam welding long, flat strips of ductile carbon steel (occasionally stainless or chrome) or fabricated from fiber composite, then coiled on a large reel for field deployment. Tubing diameters range 0.75-4.5 in. CT can have factory-installed wireline, capillary tubes, or integral tools.



Coiled strip stock stands ready for forming and welding at Tenaris Coiled Tubes' downhole manufacturing facility in Houston (Fig. 1; photo from Tenaris).

A typical, tapered CT work string will weigh 40-50,000 lb. Lead times for new tubing orders are 30-32 weeks if strip stock is in-house; 40-45 weeks if not.

According to Ronald Clarke, editor-in-chief of Moscow's Coiled Tubing Times and past chairman of the Intervention and Coiled Tubing Assoc., worldwide annual revenue for coiled tubulars is about $200 million, split between two suppliers within 4 miles of each other in Houston (Fig. 1).

"That will change" with new market entrants, he told OGJ. CT purchases are increasing about 10-15%/year and this will continue or accelerate.

In addition to market behemoths Quality Tubing and Tenaris Coiled Tubes, smaller manufacturers of coiled tubing include Cymax Coiled Tubing (UK); Fine Tubes Ltd. (UK); and Webco Industries Inc. (Oklahoma), among others.

Calgary-based Les Tomlin provides an

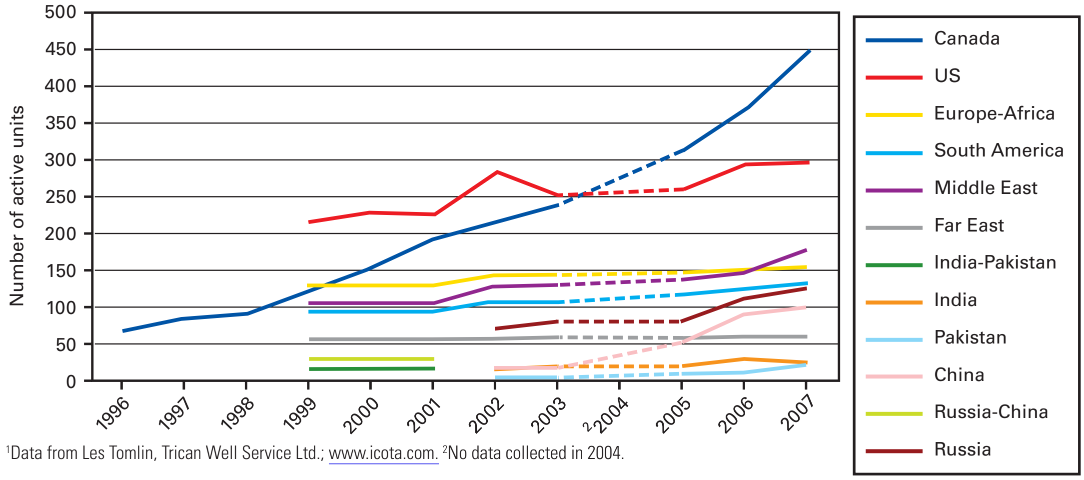
annual analysis of tubular shipments. In his 2007 count, published Jan. 18, 2007, on the ICoTA site (www.icota.com):

- Canada received 29%.
- US, 21%.
- Europe and North Sea, 13%.
- Alaska, 10%.
- Middle East, 9%.
- North Africa, 8%.
- Latin America, 8%.
- Far East, 2%.

So, North American operations currently consume about 60% of the world's CT production, excluding China.

Worldwide coiled tubing unit count[1]

Fig. 2



[1]Data from Les Tomlin, Trican Well Service Ltd.; www.icota.com. [2]No data collected in 2004.

Market—equipment

ASEP's James Goddard told OGJ the global market for new CT equipment is probably €80 million/year, based on sales of 70-80 complete units/year. HydraRig provides about 50% of all new units, Stewart & Stevenson LLC 30%, and the remainder comes from a host of smaller companies.

Coiled-tubing units include the tubing, tubing reel, injector head, control cabin, and power pack assembly. Injector heads are commonly rated 40-80,000-lb pulling capacity but can range to 200,000 lb. The largest pull, 200,000 lb, was by Baker Oil Tools in Venezuela. Graves said that only a few dozen CT units in the world are rated to 100,000 lb.

The cost of a CT unit can be broken out into five major value sections: injector head, reel, power supply, cabin-trailer-hookups, and BOP stripper, said Graves. A typical CT unit runs $1.5-1.2 million, excluding the tractor and CT string. A typical CT drilling unit runs $1.5-2 million, and a hybrid CTD unit (with mast) can cost up to $3 million.

But there are many other CT equipment designers and manufacturers in this growing market:

- ASEP Group (Netherlands; UK; US).
- C-Tech Oilwell Technologies Inc. (Edmonton).
- Fluid Design Solutions Inc. (Edmonton).
- Hydessco LLC (Kilgore, Tex.).
- Hydraco Industries (Medicine Hat, Alta.).
- Hydraulic Power Technology Inc. (Buda, Tex.).
- MXROS Inc. subsidiary Pump and Coiled Tubing (PACT; Fort Worth).
- NOV Fidmash (Minsk, Belarus).
- JSC PervoMayskHimmash (Russia).
- Stelkraft Metal Works Pte. Ltd. (Singapore).
- Surefire Industries Ltd. (Calgary).
- Total Equipment and Service (Granbury, Tex.).

Canadian companies ordered 78 new CT units in 2006. The top five are Savanna Energy Services Corp. (11), Technicoil Corp. (10); BJ Services; Sanjel Corp., and Trican Well Service Ltd. (6 each).

New coiled-tubing components await assembly in HydraRig's Fort Worth yard (Fig. 3, photo by Nina M. Rach).

CT rig count

Tomlin tabulates the annual, worldwide, active CT rig count for ICoTA, most recently updated Jan. 18, 2007 (Fig. 2). The count showed 1,535 CT rigs worldwide, up 11% from the previous year. Rig fleets showed the greatest annual increase in the Middle East (23%), Canada (21%), and Russia-China (14%). The fleet size dropped in only one region, India, which lost 5 CT rigs (–17%). Tomlin notes that some international figures could not be validated.

Market—services

About 60% of the global CT services market is dominated by oil field services companies Schlumberger, BJ Services, and Halliburton.

In the Canadian market, for instance, ICoTA Canada says Schlumberger provides 27%, BJ 18%, Halliburton 15%, followed by smaller players: Savanna, Superior Energy Services Inc., Cudd Energy Services (each 5%); Trican (4%), Complete (3%), and Weatherford (2%), with the remaining 16% shared among even smaller providers.

In the US market, 26 operators provided services with 296 CT rigs in 2006, including BJ 17%; Halliburton and Schlumberger, 13% each; Cudd and Complete, 9% each; CT Services 8%; Superior 7%; Pool Well Services, a subsidiary of Nabors Industries 3%; Arctic Recoil (Cougar Pressure Control), Warrior Energy Services Corp. and Key Energy Services Inc., 2% each; with the remaining 14% provided by 15 other companies.

CT drilling

CT drilling is commonly touted as being quicker than conventional drilling, with well completions in 20-60% shorter time.[2]

CTD can be accomplished with traditional injector-crane assemblies (no mast) or with new, built-for-purpose hybrid CTD rigs that include hydraulic drawworks, rotary table, and top drive. The injector can slide out of the way of the mast and top drive in order to run jointed pipe.

According to Canada's Technicoil Corp., general charges for drilling a 1,000-m well with a CTD rig in Canada are $1,500-2,500 (Can.)/day higher than use of a conventional drilling rig. The additional costs are related to the

drill motor (about $500 (Can.)/day) and the cycling charges on the CT string (about $1.75/m, totaling $1-2,000 (Can.)/day, depending on CT size, well depth, etc.). Cycling charges are generally only levied on forward progress, not on round trips.

There were about 75 CTD rigs in Canada in 2006, comprising about 20% of the total fleet of CT units. This is high compared with the US, which had only about 11 CTD units, 4% of the total US CT fleet, according to ICoTA.

Made in USA, Canada

The two largest manufacturers of coiled tubing rigs are both based in Texas: HydraRig, a division of National Oilwell Varco, and Stewart & Stevenson.

HydraRig, based in Fort Worth, is the world's leading manufacturer of coiled-tubing equipment, supplying both parts and complete units. Graves told OGJ that HydraRig has built 700 complete units and shipped the 1,000th injector head from its plant in May 2007. The National Oilwell Varco companies combined have built more than 900 units.

HydraRig has expanded to 320 staff from about 120 in 5 years. It provides CT units to all the major oil field service companies (Fig. 3). The company moved to a new Fort Worth facility in 2004, in order to expand and build more component pieces in house, gaining better control of delivery times, Graves said.

About 75% of the company's CT units are built in Texas, 15% in Calgary and Nisku, Alta., and 10% in the UK. Complete units require about 15 months to build to order at the Fort Worth plant, but there is less of a backlog in Canada.

Most of HydraRig's customers order trailer-mounted rigs, except for Russia and India. A typical Russian rig will run 3,500 m of 1¾-in. tubing. Customer Surgut Neftegaz has about 45 HydraRig units and recently ordered 12 units (6 CT, 6 fluid pumper) for north-central Siberia for $17.5 million.

HydraRig has sent about 30 truck-mounted units to China. A typical rig destined for China will have a reel with 15,000 ft of 1½-in. tubing.

A CT unit from Bobcat Pressure Control Inc. works on a Barnett shale well in May on the Walsh Ranch, west of Fort Worth (Fig. 4, photo by Nina M. Rach).

But Graves said many of his new CT units are staying in North America, where the industry is "hot," with about 40 units in Barnett field alone (Fig. 4).

Houston-based Stewart & Stevenson has designed and built CT equipment since 1990, with more than 300 units in the field to date. The company offers land and offshore CT units, as well as hybrid CTD units with either hydraulic or AC power; derricks up to 400,000-lb capacity; injector heads up to 200,000-lb capacity; and single or multitrailer configurations.

About half of the company's CT units stay in North America; others are sent to South America, Russia, Middle East, China, and North Africa.

Stewart & Stevenson acquired privately-held Crown Energy Technologies in February 2007. The Calgary-based company, with 1,100 employees in Canada and the US, builds CT masted units for hydraulic fracture (frac) work.

Stewart & Stevenson's Chad Joost told OGJ the Crown acquisition brought complimentary business in stimulation and workover equipment, as well as an entry to the Canadian market.

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Stewart & Stevenson is currently a privately held company but filed for an initial public stock offering in November 2006.

Texas also hosts the two main manufacturers of CT tubulars, which equally share the global market: Quality Tubing Inc., a division of NOV, and Tenaris Coiled Tubes, which acquired Precision Tubes as part of its $3.2 billion purchase of Missouri-based Maverick Tube Corp. in October 2006. Maverick had acquired Precision in 2005 for $55 million and spent $12 million in 2005-06 expanding manufacturing capacity at Precision's Houston CT plant.

Quality Tubing (QT) was founded in 1976 and purchased by Varco International in 2001. It increased its production capacity by 60% in 2006, including a new tube mill line and two new tube-mill entry lines.

QT says it can produce coiled tubing strings up to 26,000 ft long without a single girth (butt) weld. The company has four basic tubing grades: QT-700, QT-800, QT-1,000, and QT-1,200, ranging from 70,000-120,000 psi minimum yield strength, as well as QT-900 for sour service; QT-16Cr for wet CO_2 work; and H0-70 for permanent tubing installations.

Global steelmaker Tenaris SA, through subsidiary Tenaris Coiled Tubes, has two coiled-tubing manufacturing facilities in Houston, for downhole (drilling and well service) and subsea (pipelines and umbilicals associated with deepwater trees). Tenaris has four downhole-tubing grades (70, 80, 90, 110), with 1 to 5-in. OD, and 0.08-0.30-in. WT. (OGJ, June 25, 2007, p. 45). Dennis Dunlap, managing director of Tenaris Coiled Tubes, said the company uses coiled strip stock from France.

A new player is about to enter CT manufacturing. Global Tubing LLC announced last month that it would build a coiled-tubing manufacturing plant in Dayton, Tex.[4] Global Tubing President and owner Jon Dubois, who founded Quality Tubing 31 years ago, said the new company would export "to China, to Russia, and to the rest of the world."

Made in Europe

Established in 1981, the private ASEP Group has manufactured K-CTU truck-mounted (land) and containerized (offshore) coiled-tubing units and CT reels for the European market since 2000 at ASEP NL BV's plant in Groot-Ammers, Netherlands.

About 65% of the wireline and CT equipment ASEP manufactured in 2006 went to seven clients: Halliburton, Schlumberger, Baker Atlas, PSL, Seadrill, Aker Kvaerner, Qserv, and Weatherford. CT units are sold primarily to PSL Energy Services Ltd.

ASEP has two new developments: an 8 by 8 all-wheel-drive coil truck, and a four-chain CT injector head. The "QuadHead" has 80,000-lb pull capacity, stands about half as tall as a standard, two-chain injector head, and is potentially stackable, ASEP's Keith Henderson told OGJ. The grippers can accommodate tubulars to 4½-in. diameter, and two stacked units could potentially be used for jointed pipe. The new injector sells for about 30% premium over standard heads, and the first unit was just purchased by PSL.

Made in Russia

According to Steve Robertson, oil and gas manager at Douglas-Westwood Ltd., the Russian oil field services industry is set to double in value over the next 5 years.[5] Russian companies are looking to the West and beginning to adopt western business models.

One example is the reactivation and planned upgrade of a coiled-tubing manufacturing plant in Chelyabinsk, Russia. Sergey A. Gouskov is the principal at JSC UralTrubMash (UTBM), which has made CT in the past and is currently retooling for a push into the market. UTBM produces CT with 20-57 mm ID, in strings as long as 4,500 m.[6]

Earlier this year, Leonid Gruzdilovich, president of the FID Group, said FIDmash has produced four generations of coiled tubing equipment, 1999-2007, with primarily Russian-made components.[3] He said 50% of this year's deliveries will be made to international servicing companies (up from 24% in 2006), 30% to companies in the CIS (same in 2006), and 20% to Russian oil and gas production and servicing companies (down from 46%).

For the last 7 years, FIDmash has dominated the Russian market of CT equipment," Gruzdilovich said, with "70% produced by us, about 13% by Hydra Rig, and about 4% by Stewart & Stevenson." Another 13% of the purchased units were produced elsewhere in Russia.

The coiled-tubing equipment market in Russia is small, he noted. The average Russian company has 2-5 units at most. Larger companies have more; for example, Gazprom owns 30 units and Surgutneftegaz owns 27.

CJSC FIDmash was established in 2001 in Minsk, Belarus, and was acquired by National Oilwell Varco in December 2005.[7]

NOV Fidmash says its strategic aim is to provide equipment to Russia, CIS countries, Eastern Europe, Central Asia, and the Middle East. The company has supplied CT equipment to Schlumberger, BJ Services, Gazprom, Rosneft, SurgutNeftegas, Tatneft, Bashneft, Ukrneft, Ukrgazodobicha, and others.

Graves told OGJ that FIDmash had built about 50 CT units for the Russian market. Some NOV Fidmash CT units include HydraRig injectors and Texas Oil Tool BOPs. Unit output doubled in 2006 from the previous year and he expects it to double again in 2007.

A smaller Russian company, PervoMayskHimmash, produces light-duty CT units. Two Russian operators mentioned purchases. Vladimir Dmitruk, of gas producer Nadymgazprom, said his company uses CT for 37% of its well repairs (about 18/year). It bought a CT unit built by Rebound Rig Co. Ltd. in 1994, a Belarus-made M10 from FIDmash in 2005, and plans to buy a URAN-20.1 from PervoMayskHimmash this year.[8]

Nikolai Rakhimov, chief engineer at Urengoigazprom, said the company uses CT equipment for about half of the 90-120 well repairs it performs each year in the Urengoi oil-gas-condensate field. The company has purchased CT units from FIDmash and PervoMayskHimmash.[8]

Tatneft has CT units built by HydraRig, Stewart & Stevenson, and FIDmash.[8] Orenburggazprom bought a single M-20 unit built by FIDmash in 2002, for work in Orenburg oil-gas-condensate field.

Russian expertise

In a recent interview, Aleksandr G. Molchanov, professor and department head at I.M. Gubkin Russian State University of Oil & Gas, discussed the primacy of Russia's SurgutNeftegaz in coiled-tubing expertise. It's the "best-equipped Russian company in…CT and CT tools [and] can broadly apply CT technologies," he said.[9]

Molchanov acknowledged that "CT drilling is still considered in this country a rather exotic process" but that SurgutNeftegaz is drilling with CT beyond 2,000 m.

Independent Russian oilfield service companies offering CT include: Eurasia (CTD only); CJSC Uralmash-Burovoye Oborudovaniye, purchased by Integra Group in 2005; RITEK, a subsidiary of Lukoil, and others.

Weatherford International will open the first coiled tubing-conveyed tool rental workshop in Russia in Nizhnevartovsk in second-half 2007. The equipment will target well repairs and will include small motors, mills, impact hammers, fishing tools, and packer systems.[9]

Future

Coiled tubing is nearly recession-proof, Ronald Clarke said. When drilling is down, workover activity increases; when drilling is up, CT units are either engaged in drilling or well completions. Upside: CT companies often show EBIDTA (earnings before interest, taxes, depreciation, and amortization) of 40% or more. Downside: coiled tubing is becoming a commoditized product.

Regardless, the market seems likely to continue to expand at least 10-15%/year for the foreseeable future. ✦

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Method calculates lean, semilean streams in split-flow sweetening

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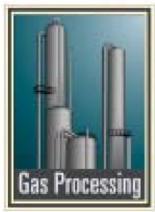


Alkanolamines are used widely in gas treating plants. Because acid-gas removal from natural gas requires regeneration of alkanolamines, the energy requirement for the stripping section (condenser and reboiler) will be much greater when the inlet sour gas contains a high concentration of acid gases.

In these cases, a split-flow process can reduce energy consumption. Two solvent streams called lean and semilean streams are used.

A new method has been devised for calculating these stream rates. The procedure is based on simplifying assumptions that permit quick shortcut calculations.

The proposed method has been tested for two plants, the Okotoks sweetening plant in Canada and the Razi petrochemical complex in Bandar Imam Khomeini, Iran, with acceptable results achieved.

Natural gas sweetening

Natural gas, one of the most important energy sources, contains light hydrocarbons (predominantly methane) and some contaminants. From these contaminants, hydrogen sulfide and carbon dioxide should be removed because of health and environmental problems and to lower transmission costs.

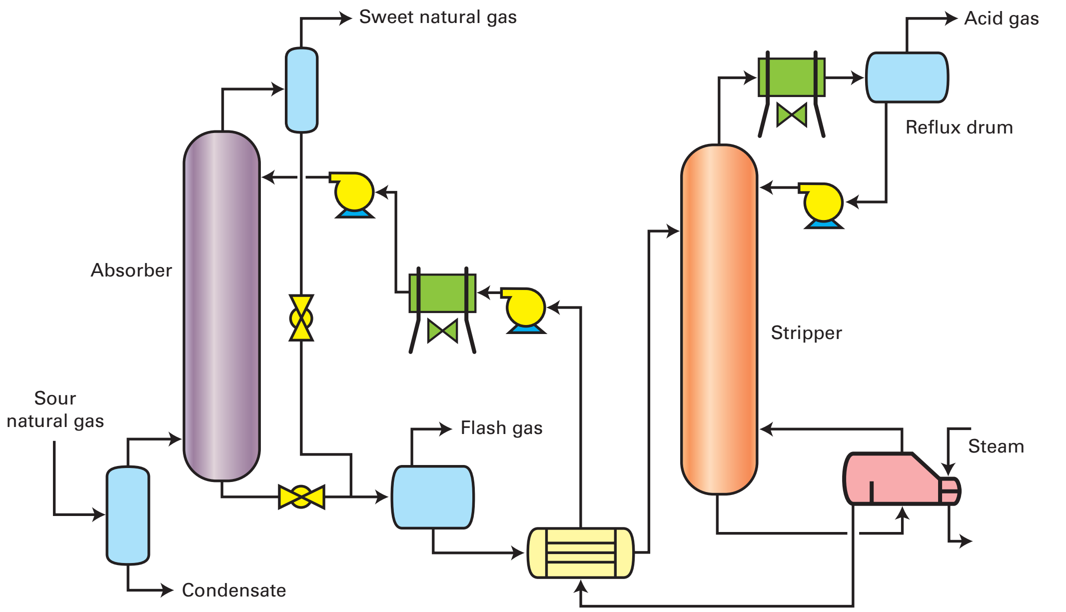
Several sweetening technologies exist. Among these, alkanolamines are the most widely used solvents for absorbing H_2S and CO_2 and have been used since the 1930s.

Fig. 1 shows a basic flow scheme for alkanolamine treating. Inlet gas that usually contains CO_2 and H_2S enters the absorption section and contacts a lean amine stream in the column.

Amine solvent absorbs acid gases and leaves the contactor bottom as rich amine. The sour gas loses acid gas contaminants and flows from the contactor top as sweet gas.

CONVENTIONAL AMINE SWEETENING

Fig. 1

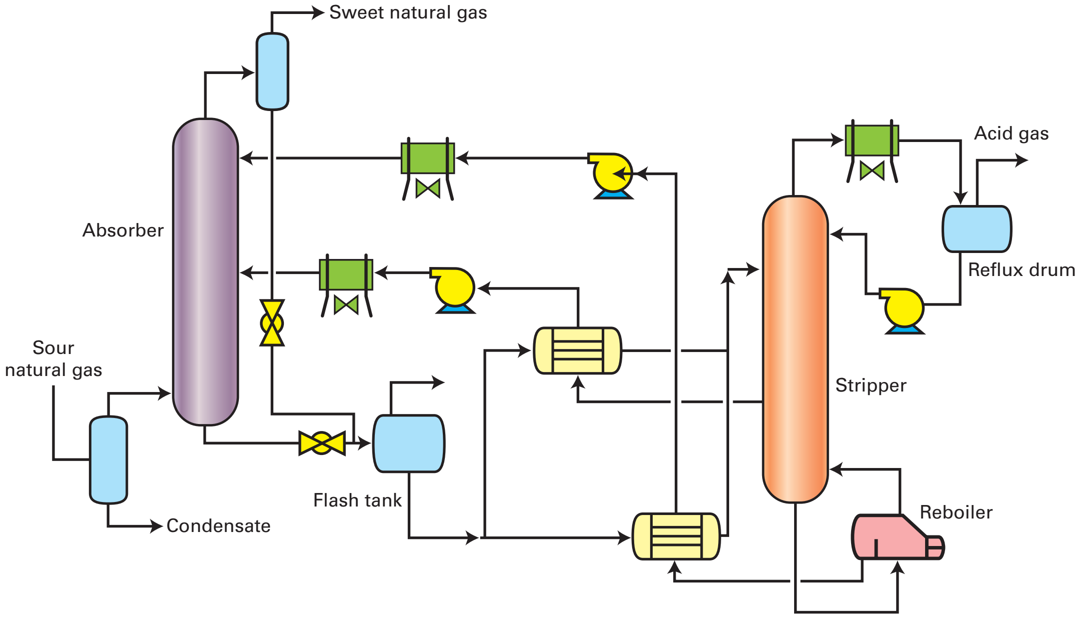


Rich amine passes through a flash drum and lean-rich heat exchanger. The stream then enters the regenerator column. In this section, acid gases are released from the amine and leave the tower's top; high-temperature regenerated amine is drawn from the regenerator as bottom stream.

After being cooled and pumped, this lean amine stream enters the absorber.

Split-flow process

Fig. 2



Modifications

Some modifications can improve the operating conditions and enhancement in gas treating.

All of these modifications fall into four configurations:

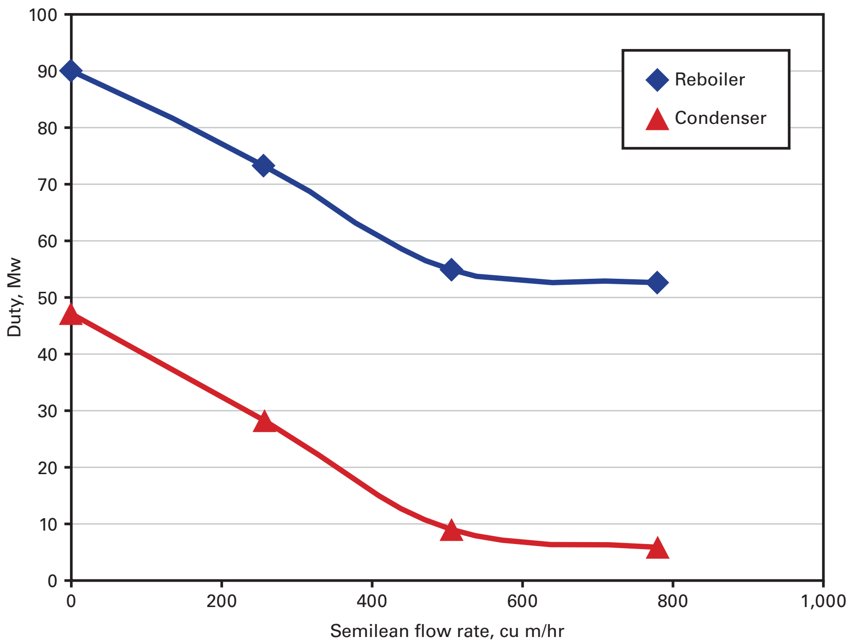
- Adding a precontactor in the path of sour gas.
- Using multiple feed points in the absorber.
- Using a split-flow configuration in which semilean amine is fed to some midpoints of the absorber while ultra-lean amine is fed at the top (Fig. 2).
- Installing pressure-swing regeneration instead of reboiling.

All of these modifications have advantages and drawbacks. Gas treating with split-flow has a greatly reduced energy use in the plant. In the conventional process, all amine leaving the contactor is regenerated; in the split-flow process, some solvent is withdrawn from the regenerator (partially stripped) and enters the midpoint of the contactor for bulk removal of acid gases.

This means that the bulk of absorption is a compulsory condition of using the split-flow process in gas-treating plants. There are no major changes in the total amine flow rate, but because the stream from the regenerator has a lower amine composition, the total circulation rate is greater than before.

Energy reduction

Fig. 3



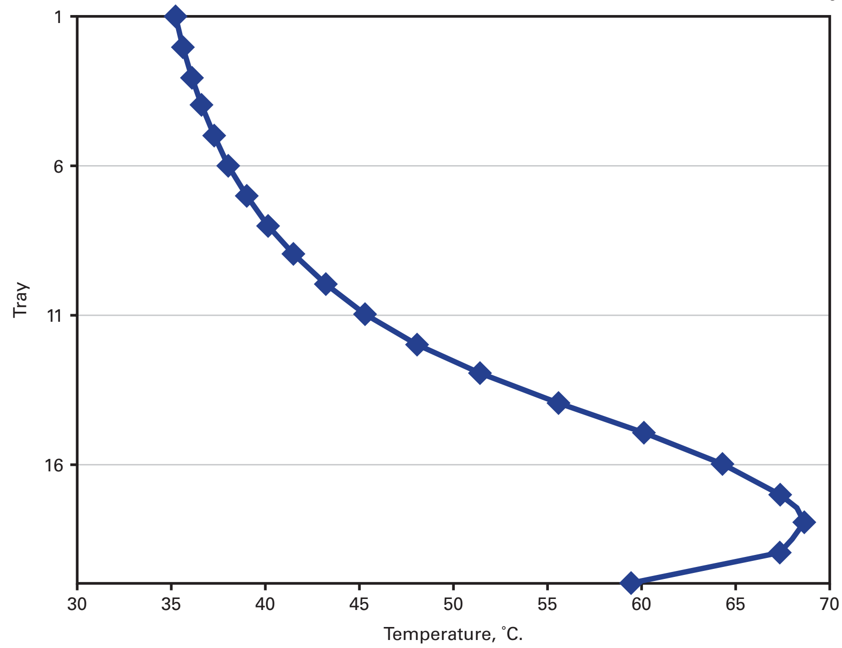
If the processor decides to treat sour gas with the split-flow process, a calculation algorithm based on the conventional procedure can be used to calculate the required lean and semilean amine flow rates.

Fig. 3 shows the semilean amine flow rate and the effect on the condenser and reboiler duties in the stripping column of the Razi petrochemical complex's (RPC) gas-treating plant. These rates are

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags

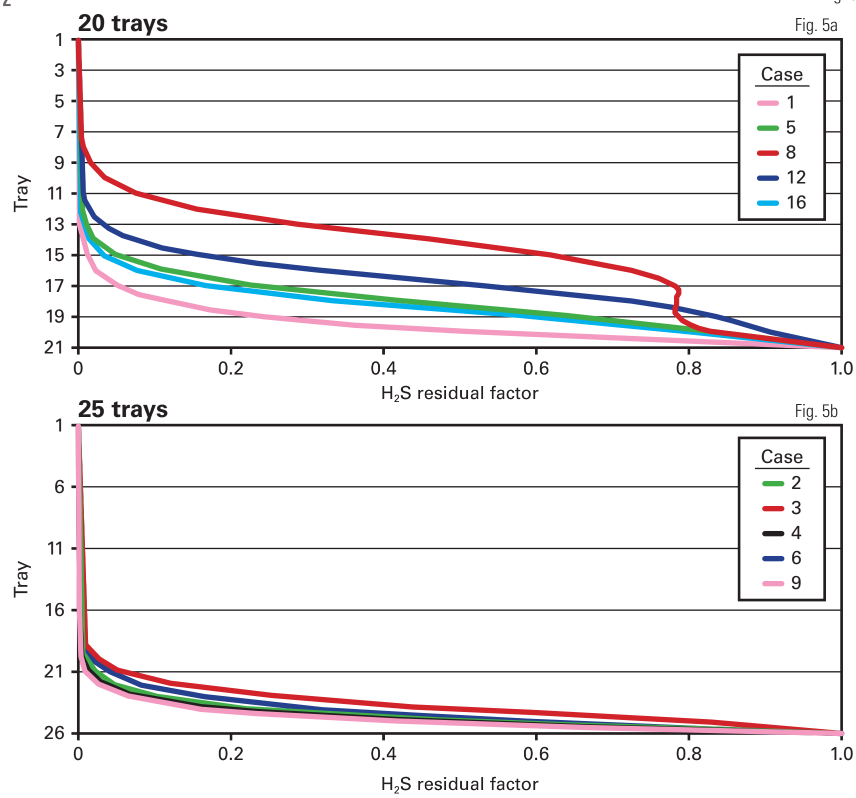
CONTACTOR TEMPERATURE PROFILE

Fig. 4



H₂S RESIDUAL FACTORS

Fig. 5



calculated with Amsim[1] as sweetening simulation software and our proposed procedure.

For a specific case, we simulated the conventional and semisplit flow. At a semilean flow rate of zero (conventional amine process), we calculated the lean amine rate at about 790 cu m/hr. The stripper and condenser duties were about 90 Mw and 47.7 Mw, respectively.

In the split-flow process, these duties are reduced to 54.5Mw and 8.6 Mw with lean and semilean flow rates of 390 cu m/hr and 507 cu m/hr, respectively. Due to the higher solvent rates for the split-flow case, a larger unit is needed.

Split-flow processing

The main concept in split-flow is that most of the acid gases are removed from sour gas in the contactor's lower section. Because absorption with amines is an exothermic reaction, the temperature of liquid across the column increases when flowing down through the trays.

Fig. 4 shows a typical temperature profile across the column.

The temperature profile, however, is an unsuitable way to monitor absorption effectiveness. A parameter is needed to show the amount of absorption in the tower. This parameter can be more useful if it is independent from the feed composition and rate, amine rate, and type of amine and composition.

We propose using a parameter called the residual factor, defined as the difference between the vapor composition of the gas leaving each stage and sweet gas divided by the difference between sour and sweet gases compositions:

$$\text{Residual factor} = (y_m - y_1)/(y_{n+1} - y_1)$$

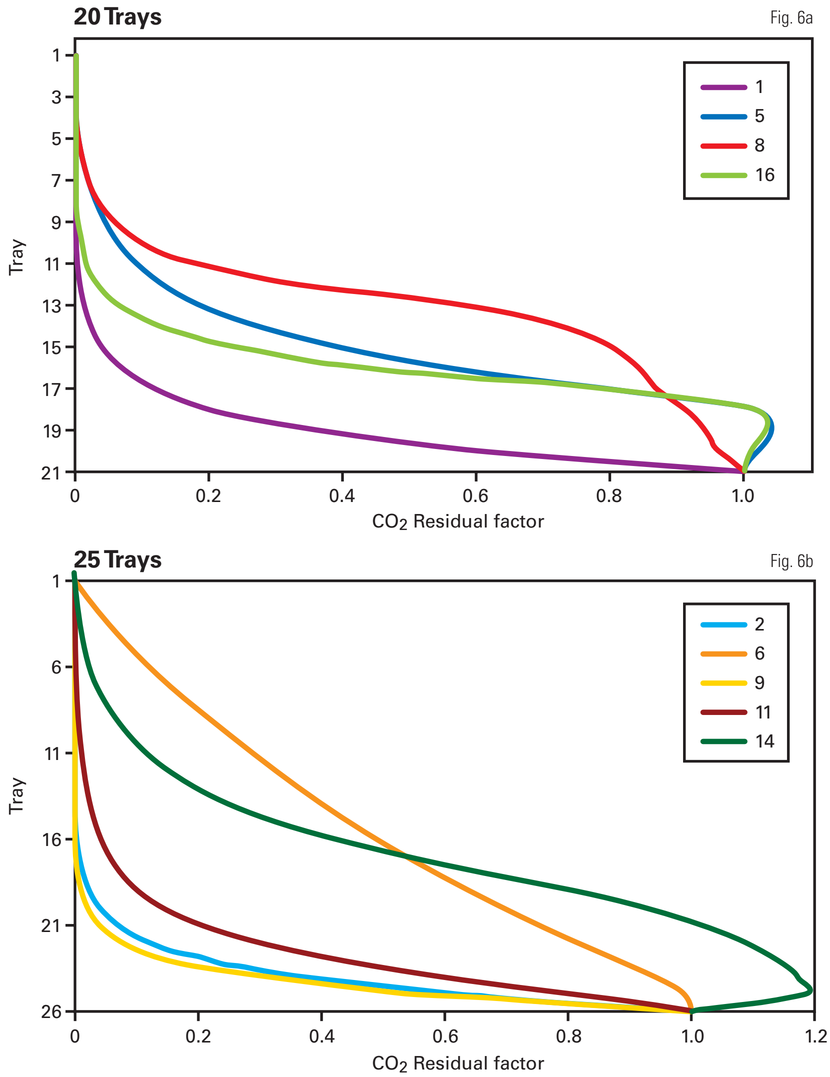
Where y_1 is the composition of a specified component in the sweet gas, y_m is the composition of a specified component in gas leaving stage m, y_{n+1} is the composition of a specified component in the sour gas, and n is the number of stages in tower.

This factor varies between 0 and 1; it is 0 at the top and 1 at the bottom.

We simulated and studied 16 different cases to obtain a general trend or algorithm. In these cases, different feed rates, compositions, and

CO_2 RESIDUAL FACTORS

Fig. 6



DATA FOR SIMULATION CASES

Table 1

Case	Number of trays	Amine type, composition, wt %	Gas flow, kg-mole/hr	H_2S, mole %	CO_2, mole %
1	20	MEA, 20	1,494.0	8.0	5.0
2	25	MEA, 15	996.0	3.0	3.0
3	25	MEA, 20	2,490.0	25.0	15.0
4	25	MEA, 14.7	12,151.2	2.1	0.156
5	20	DEA, 40	4,980.0	15.0	10.0
6	25	MDEA, 40	3,984.0	4.76	6.6
7	30	DEA, 10 + MDEA, 40	9,960.0	9.0	8.0
8	20	MEA, 20 + MDEA, 30	4,482.0	4.0	10.0
9	25	MEA, 14.8	11,967.9	2.5	0.2
10	24	DEA, 30	9,093.5	1.3	2.8
11	25	DEA, 35	5,229.0	—	10.0
12	20	MDEA, 40	5,478.0	10.0	—
13	30	MDEA, 35	9,960.0	1.0	8.0
14	25	MDEA, 25	2,490.0	5.0	12.0
15	30	DEA, 32	9,960.0	2.0	8.0
16	20	MEA, 25	4,980.0	15.0	2.0

amine types were tested for different columns. We used 20-30 trays in the simulation; this is common in the gas-treating industry. Table 1 shows the cases that we simulated.

We calculated removal efficiencies for each component (H_2S and CO_2) in each stage with the Amsim software using a rate-based method.

Figs. 5 and 6 show H_2S and CO_2 composition profiles and residual factors for selected cases.

Most H_2S absorption curves behave similarly and normally, which we call "normal" cases. Some of them deviate from normal behavior, which we refer to as "abnormal" cases.

In normal cases, most absorption occurs in the absorber's lower section. The gas temperature and acid-gas composition rise and fall rapidly, respectively. In the abnormal cases (Cases 6, 8, and 14), however, there is a noticeable deviation in H_2S absorption. After careful observation, we found that in these cases, absorption of CO_2 controls the amine circulation rate. In other words, the total rate of required amine to absorb the CO_2 is greater than the rate of required amine for H_2S removal.

Fig. 6 shows that some of the curves change gradually due to the same reason. Our calculation procedure, therefore, is based on the assumption that most absorption occurs in the column's lower section. The procedure's first assumption, however, is that H_2S should control the amine rate.

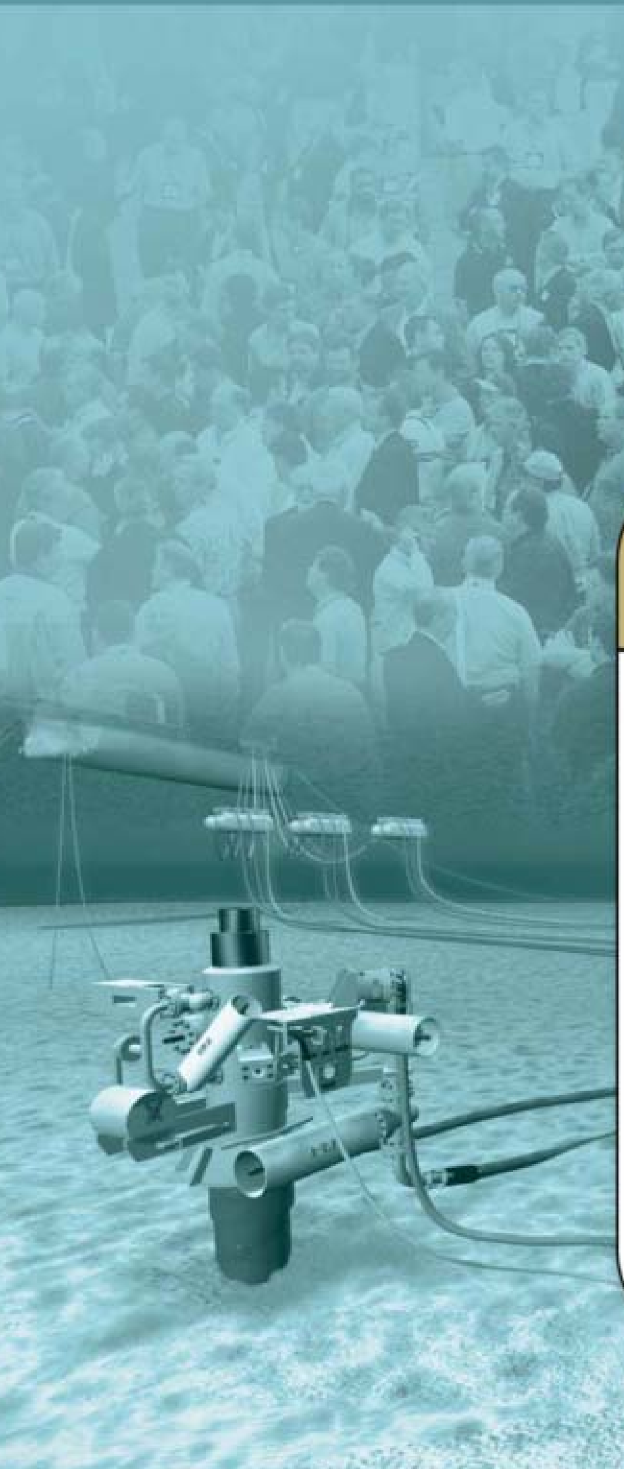
When CO_2 controls the amine rate, however, the procedure requires some revisions and extra attention. One must check the composition profile to see if most absorption is obtainable in the lower section. The residual factor is an excellent tool for this purpose. Then, the entire calculation sequence should be performed exactly the same as that of H_2S.

Fig. 7 shows the procedure to evaluate the possibility of applying the split-flow process.

Calculation procedure

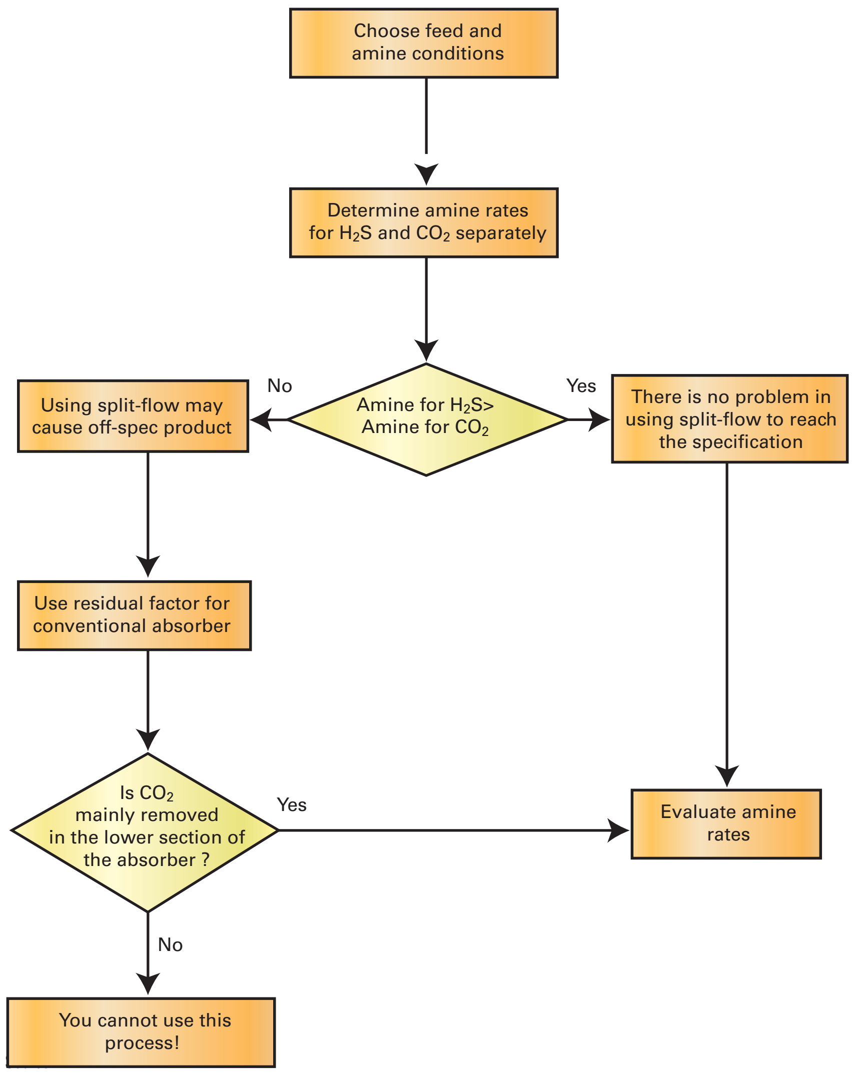
This procedure shows how to calculate amine rates for H_2S and CO_2 (Fig. 8):

1. Assume a lean stream composition. It may be free of acid gases assum-



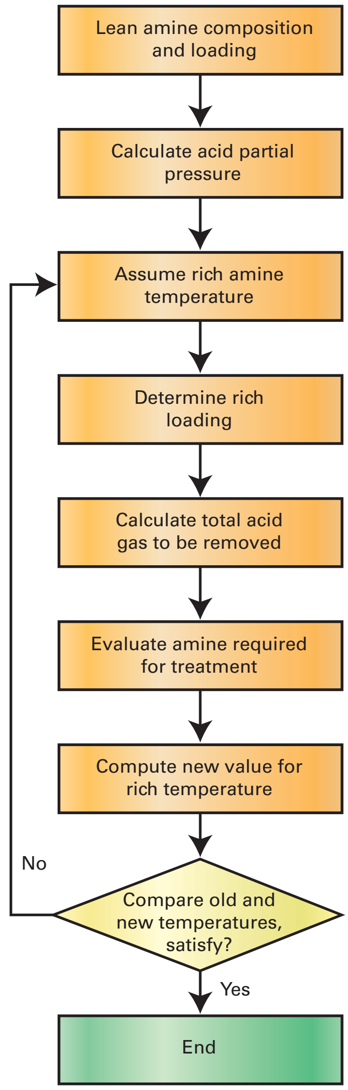
Split-flow decision procedure

Fig. 7



Lean amine calculation

Fig. 8



Case study conditions

Table 2

Specifications	Example 1, Razi petrochemical complex	Examle 2, Okotoks gas treating plant	Example 3
Feed conditions			
Flow rate, kg-mole/hr	4,299.73	1,467.3	2,490
H_2S rate, kg-mole/hr	1,070.63	505.5	249
CO_2 rate, kg-mole/hr	468.67	157.4	124.5
Other (including hydrocarbons), kg-mole/hr	2,760.43	804.4	2,116.5
Temperature, °C.	48.9	14.4	37.8
Pressure, kPa	4,721.3	3,792.1	4,826.3
Amine type	DEA	MEA	DEA
Amine, wt %			
Lean	28.4	20.1	25
Semilean	22.6	13.8	18

ing complete regeneration in the stripper. In other words, lean amine loading equals 0. Use the actual lean stream composition if available. Fitzgerald and Richardson proposed extracted loading of monoethanolamine depending on the steam consumption, or it may be available from real plant data.[2]

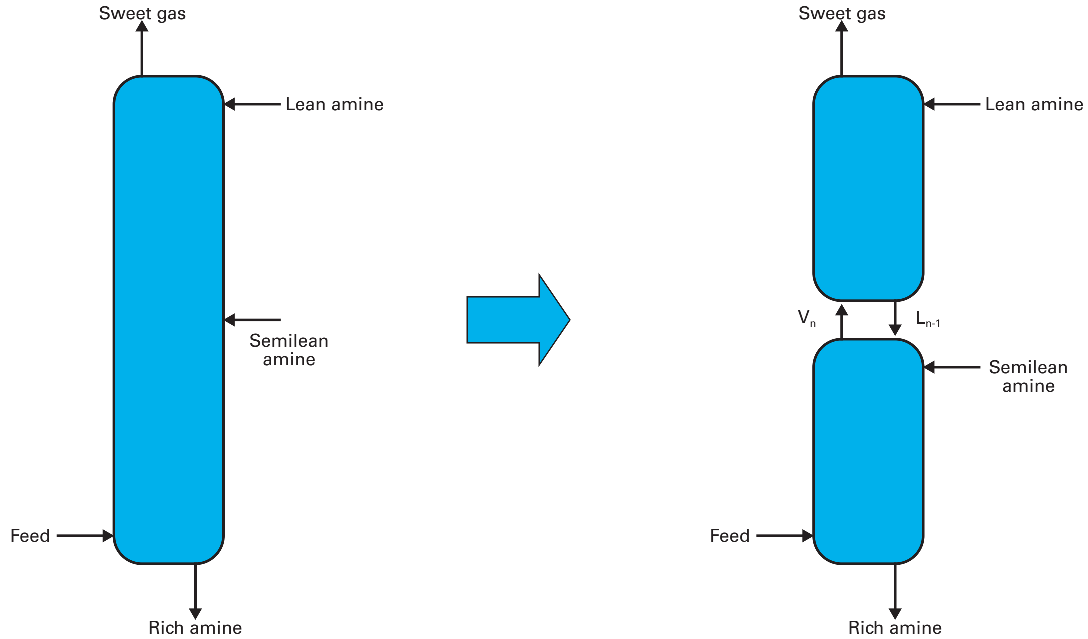
2. Determine partial pressures of H_2S and CO_2 in the feed sour gas and assume an appropriate temperature for the rich amine stream.

3. Calculate the rich amine loading using either experimental data and charts or a computer calculation. Some experimental data are available in the literature or simulation software may be used. EzSweet software, developed for amine gas sweetening processes, can estimate solution loadings in equilibrium with acid gases.[3]

Corrosion due to high acid-gas loading is a limitation to consider, especially in spilt-flow processes in which inlet sour gas contains large amounts of acid gases.[4 5] In our study, the maximum allowable loading is 0.5 mole H_2S /mole

SEPARATING CONTACTOR INTO TWO ABSORBERS

Fig. 9



RESULTS FOR THE THREE CASES

Table 3

	Calculated lean stream flow rate	Calculated semilean stream flow rate	Total rate Calculated	Total rate Plant data
	cu m/hr			
Example 1, RPC	395	507	902	930
Example 2, Okotoks plant	90.85	342.3	433.1	464
Example 3*	144.68	373.84	518.5	

*In this example, CO_2 controls amine rate. Drawing a residual factor chart shows that total absorption takes place in lower part of the contactor. All procedure steps should be performed for CO_2.

amine for the RPC and Okotoks gas-treating plants. This value is from the plant operating guidelines.

Maximum loading should otherwise be at the discretion of the designer to avoid corrosion problems during operation.

4. Calculate the total amount of H_2S and CO_2 that must be removed from natural gas. A good assumption is that all of the acid gases will be absorbed. For example, for primary and secondary amines, there is a trace residual amount of CO_2 and H_2S in the sweet gas. But we can neglect this amount because no major differences in the results occur.

5. Divide H_2S and CO_2 rates by the loading of these compounds and determine the amount of necessary amine for absorbing acid gases.

6. Perform an energy balance around the absorber or use a simulation program to recheck the assumed temperature of rich amine. This is important for calculating the loading of acid gases. If the difference is not small enough, repeat the second step.

Shortcut method

The most important part of this procedure is dividing the absorber into two separate columns (Fig. 9). Liquid from the top section enters the lower section and vapor from the lower section enters the top section.

Using this simple shortcut method separates easily the total mass balance into two mass balances.

Here are the steps in this method:

1. Assume that 99.5% of the H_2S is absorbed in the lower section. Calculate the amount of H_2S in stream V_n. This value (99.5%) is reasonable. The amount of H_2S in this stream should be absorbed by the lean amine.

2. Assume that a portion of the required amine calculated in the conventional calculation enters as lean amine into the column's top section. A good initial value is half of the total amine. This value can be corrected if necessary when optimizing.

3. Calculate loading of stream L_{n-1}. Assume that the total H_2S in stream V_n is removed by lean amine and is available in stream L_{n-1}.

4. Assume that the loading of stream L_{n-1} and the semilean stream are close in composition. This may not be true in reality but it is the best assumption for a quick calculation. If the semilean stream loading is available from past experience or plant data, results will be better.

Assume also that loading and temperature of the rich amine solution calculated in the conventional process calculation are equal to loading and temperature of rich amine in this part and calculate the total required amine in rich stream.

5. Evaluate the flow rate of amine in the semilean stream. This rate of amine is the sum of amine in lean and semilean streams.

Simulation results

We tested two cases—RPC, Iran, and Okotoks, Alta.—to demonstrate the application and accuracy of the proposed method. Furthermore, we have studied a third, unnamed case to demonstrate reliability of the proposed method.

Table 2 shows the conditions for three case studies and Table 3 shows the results of the three case studies.

The calculation method shows good agreement with plant data.

Determination of the lean amine rate for conventional amine treating plant is well known and straightforward. For split-flow gas treating, however, calculations of lean and semilean stream rates are complex.

This method eliminates the complex computations that have been done in the past for simple absorptions.[6,7] Some simple assumptions prevent tedious calculations. This procedure is appropriate and applicable to estimate amine solvents at the design stage of the plant or during optimization procedure. It can also be used to determine lean and semilean streams rate for an operating plant. ✦

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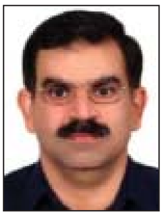

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Study examines Chinese SPR growth alternatives

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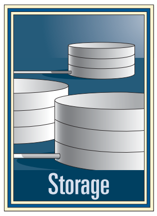


Development of China's strategic oil reserve system depends largely on the mindset of its decision makers.

Conservative, security-driven thinking will lead to higher costs for the government and more stress on the global oil market. A more open-minded approach, by contrast, could allow an efficient and comparatively inexpensive build of reserves.

This article will examine the strategic petroleum reserve strategies used by the US, Japan, and South Korea, in an effort to determine the optimum course for development of China's reserves.

Background

China's demand for oil has become a global political and economic issue. China imported 2.9 million b/d of crude oil in 2006 and roughly 1 million b/d of refined products. It is the second largest oil consumer and third largest oil importer in the world. Net imports of oil (crude plus refined products) account for nearly half of its oil consumption(Fig. 1).

Against this backdrop, China has begun building a strategic stockpile of oil. By mid-2007 the Chinese government had filled the first strategic petroleum reserve storage site at Zhenhai, Zhejiang province; 12.4 million bbl nearly completely. Total capacity at Zhenhai's SPRs is 5.2 million cu m (33 million bbl), split among 52 storage tanks.[1]

High-level discussion on the need for SPRs began after China became a net importer of oil in 1993. China's Tenth Five-Year Plan, passed by the National People's Congress in 2001, declared the goal of developing strategic stockpiles. Construction for the first four sites, however, did not begin until June 2004.

China's SPR

China's SPR plan has three phases.

- Phase I (2004-08) includes construction of one stockpiling facility each in Zhenhai and Aoshan in Zhejiang province, Qingdao in Shandong province, and Dalian in Liaoning province, with a combined storage capacity of 100 million bbl (25 days of China's net oil imports).
- Phase II will increase storage capacity to 300 million bbl by 2010 (42 days of net oil imports).
- Phase III could increase storage to 500 million bbl.

China ultimately plans sufficient strategic petroleum reserves to cover 90 days of imports, which is also the mandatory goal of the International Energy Agency's 90 days of forward cover initiative. FACTS' forecast shows that to cover 90 days of net oil imports in 2015, China will need to have 625 million bbl of oil in storage.

Sinopec is overseeing construction of the Zhenhai site, which sits adjacent to its massive Zhenhai refinery. Sinopec is also responsible for construction of the Huangdao site, while PetroChina and Sinochem are building at the Dalian and Aoshan sites, respectively.

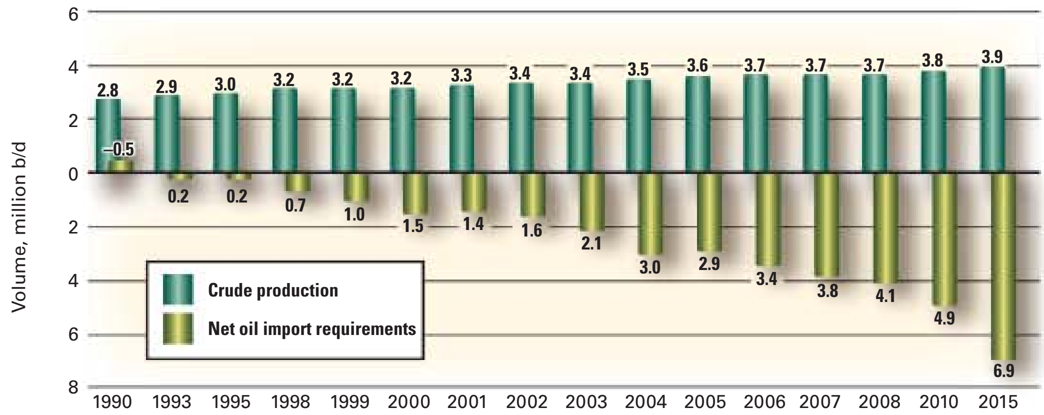
China's state oil companies, however, will not manage the SPRs. The nascent State Oil SPR Office and State Oil Stockpiling Center will instead perform this role, having been established a few years ago for this purpose by the National Development and Reform Commission.

Sinopec completed construction of 52 100,000-cu m crude tanks at the Zhenhai base in August 2006. Construction of the three other storage bases in Aoshan, Huangdao, and Dalian is expected to be completed in 2007-08. Aoshan, like Zhenhai, will store roughly 5 million cu m (31 million bbl) of crude, while the Huangdao and Dalian sites will be smaller at 3 million cu m (19 million bbl) each.

Phase I of China's stockpiling plan, which the government seeks to complete by the end of 2008, will therefore include roughly 16 million cu m (103 million bbl) of crude oil, equivalent to about 35 days of China's current net oil imports, or 15 days of total oil con-

CHINA: CRUDE PRODUCTION, NET IMPORT REQUIREMENTS*

Fig. 1



*Data for 1990-2005 are actual; data for 2006 are preliminary; data for 2007-15 are forecast.
Source: FACTS Global Energy

sumption.

Sources within China have revealed glimpses of China's future stockpiling plans. Phase II plans call for an additional 200 million bbl of tank storage, slated for completion by 2010. The country has begun looking for new sites to build this second batch of strategic petroleum reserves, including Caofeidian, Tangshan (Hebei province), Nansha, Guangzhou (Guangdong province), and Bao'an, Shenzhen (Guangdong province).

The planned Caofeidian storage has a capacity of 15 million cu m (94 million bbl). The city signed an agreement with Sinopec to build a 300,000-tonne crude terminal; construction has already begun. Handling capacity is 400,000 b/d. China will build a crude pipeline of the same capacity connecting Caofeidian with Tianjin. Total investment will be 3 billion yuan ($383 million).

Nansha is the location of a proposed 240,000-b/d Sinopec-KPC refinery and 1 million tonne/year ethylene plant. Titan Petrochemicals Ltd. of Singapore plans to build oil storage there. The city government of Shenzhen plans to build new oil and gas storage at Bao'an, Longgang, and Nansha.

China has also started preparations for a huge underground oil storage facility, the first of several planned underground storage sites being looked at in the city of Zhanjiang. According to local government, the storage caverns will hold 7 million cu m (44 million bbl) of oil, and construction will cost 2.3 billion yuan.

China's Phase III plans call for an additional 200 million bbl of tank storage. Few details are available about these plans, but some SPR sites will be built in interior provinces such as Sichuan and Xinjiang.

Reserve strategy

According to Ma Kai, head of the NDRC, China's top energy planning body, China's SPRs will implement a dual oil reserve strategy that includes government and private strategic oil reserves. Besides having a government-managed SPR, the government will require that China's four state-owned oil companies hold their own government-mandated oil stocks, imitating Japan's stockpiling system.

The government also encourages large oil companies to build their own commercial oil reserves.

Operation mechanism

Sinopec, PetroChina, and Sinochem are only responsible for the construction of SPR facilities and will not manage and operate them. Established under the Bureau of Energy within NDRC, the State Oil Stockpiling Office is a governmental department, while the State Oil Stockpiling Center is much like a state-owned company and is directly responsible for the management and operation of China's SPR. The full nature and structure of these organizations, however, remains unclear.

Oil companies

China's State SPR Office lies inside the BOE within the NDRC. The director of the State SPR Office is also a deputy director of the BOE.

On Feb. 2, 2007, the National Energy Leading Group of the State Council said that SPR regulations will be part of the new energy law drafted by the National People's Congress. Currently, oil storage held by Chinese state oil companies is considered commercial storage. State oil companies, however, will eventually participate in China's SPR program.

On Feb. 5, 2007, the NDRC approved terminal expansion projects for Sinopec at Zhenhai and Sinochem at Aoshan, both in Zhejiang province. Sinopec will turn two small berths into a 250,000-tonne crude and product terminal with 150,000-b/d capacity. Sinochem plans to build a 300,000-tonne crude terminal at Aoshan with 300,000-b/d capacity.

Strategic, commercial

Ever since the Zhenhai SPR site started injecting crude in August 2006, controversy has surrounded the role of SPRs in China. Data show that of the 25 million bbl stored at Zhenhai SPR, nearly half have been leased to Sinopec. The NDRC insists that leasing SPRs is consistent with SPR principals, but others have raised questions regarding this practice. The rule itself is unclear, although the Chinese government promises to clarify how the SPR sites and crude should be used when the full legislature governing SPRs is completed.

Existing models

The US, Japan, and South Korea are the three consuming countries that have so far instituted SPRs.

- *US.* The US government operates the largest and most efficient public petroleum stockpile in the world. The US established its SPR in 1975 under the Energy Policy and Conservation Act in response to the 1970s oil embargo. As of Mar. 2, 2007, the US SPR held 688.6 million bbl of oil at four storage sites in Texas and Louisiana.

The presence of salt domes along the US gulf coast allows for large, cheap, and efficient oil storage, rapid drawdown, and minimal maintenance costs compared with other modes of storage.

The US Department of Energy operates the SPR and fills it via a royalty-in-kind program devised by the Clinton administration in 1999. Through this program, the DOE's Minerals Management Service collects royalties as oil from companies operating government offshore leases in the Gulf of Mexico, and uses this oil to fill the SPRs. Prior to 1999, MMS collected these royalties in cash.

When President George W. Bush was inaugurated in 2001, the SPR held just under 600 million bbl of oil. Following the terrorist attacks of Sept. 11, 2001, President Bush instructed the DOE to fill the SPR to 700 million bbl, close to its capacity of roughly 730 million bbl.

The comprehensive energy bill passed by the US Congress in July 2005 calls for expansion of the SPR to 1 billion bbl, as long as purchases of oil for the reserves do not raise oil or oil product prices.

As the world's leading importer of oil (13.5 million b/d in 2005)[2] and dominant global economic and military power, the US governs its oil stockpiles conservatively. Government policy dictates that oil from the reserve can be released only by order of the president and in case of a disruption to oil supply.

Only two emergency drawdowns of the US SPR have occurred; one in 1991, the other in 2005. In January 1991, in response to oil market anxiety created by the Gulf War, the mere announcement of President Bush's plans to release oil brought a measure of stability to the market.

The second emergency drawdown occurred after Hurricane Katrina caused massive damage to oil production facilities, terminals, pipelines, and refineries along coastal regions of Mississippi and Louisiana in late August 2005, causing gasoline prices to spike. In September 2005, through a coordinated action with the IEA, President Bush ordered the drawdown and sale of 30 million bbl of crude oil from the SPR to US markets. The IEA, which serves as the main supranational entity coordinating energy information and policy among developed countries, mandated a drawdown correlated with the US release.[3]

Any other US SPR releases have been limited to test sales and exchange arrangements with private companies.

- *Japan.* Japan's model is the most expensive and comprehensive system of strategic oil stockpiling in the world. Japan imports more oil than any other country besides the US. Unlike the US and China, however, Japan produces no domestic oil.

Japan has divided its system of petroleum stockpiling into two sets of reserves: public and private. Roughly 320 million bbl of crude, managed by the Japan Oil, Gas, and Metals National Corp. under the Ministry of Economy, Trade, and Industry, comprise the government-managed strategic petroleum reserve.

Ideas and guidelines that govern these stockpiles are similar to those applied to the US SPR, but Japan has no salt caverns and has therefore needed to invest heavily in other methods of storing oil.

JOGMEC provides information on 10 national stockpiling bases accounting for roughly 215 million bbl of oil. This includes 112 million bbl in aboveground tanks, 51 million bbl in floating tanks, 30 million bbl in rock caverns, and 22 million bbl in underground tanks.

Aboveground tanks and rock cavern storage both represent financially appealing alternatives to salt caverns. Underground and floating tanks are much more expensive but demonstrate Japan's efforts to protect its reserves from natural disasters such as earthquakes and typhoons.

The second part of Japan's strategic stockpile consists of government-mandated private storage. Private Japanese oil companies and importers of refined products must maintain stocks equivalent to 70 days' consumption. According to JOGMEC, private stocks amount to nearly 275 million bbl of oil, or 82 days' forward cover. Crude oil comprises about half the private stocks, with oil products making up the balance.[4]

The stockpiling requirement is subsidized by the Japanese government but still constitutes a significant burden on Japanese oil companies and a large barrier to entry into the Japanese market.

The Japanese government's drawdown policy is more rigid than that of the US. Japan's nearly 600 million bbl of oil is the only reserve in the world that approaches the size of US SPR. Japan consumes less than a fourth and imports less than half as much oil as the US. Therefore, Japan's system provides extensive protection against supply disruption, but at a very high cost.

In marked contrast to China and the US, Japan's oil demand is shrinking, improving the strength of its reserves.

After a recent internal evaluation of its stockpiling practices, Japan plans to increase the strength, flexibility, and readiness of its reserves, including reducing private companies' stock requirements to 60 or 65 days.

- *South Korea.* The South Korean strategic stockpiling model differs from the rigid approaches of Japan and the United States. Under government auspices, Korean National Oil Co. main-

tains about 63 million bbl of crude oil, 7.3 million bbl of petroleum products, and 3.6 million bbl of LPG. KNOC stores about 80% of these stocks in rock caverns, with aboveground tanks housing the remainder.

KNOC plans to increase the public stockpile to 140 million bbl by 2008. Current stockpiling locations have 114 million bbl in capacity. [4]

Private Korean oil companies must maintain 40 days of forward coverage for domestic sales, equal to roughly 72 million bbl of oil.

KNOC manages Korea's public oil stockpiles with flexibility in an effort to recoup some of the expense associated with building and maintaining stocks. The company occasionally conducts time swaps, which entail taking advantage of fluctuating oil prices by lending oil from national stockpiles. Korean refiners (and sometimes international oil purchasers) are invited to bid on a quantity of stockpiled oil. The winning bidder must return the oil within a stipulated period to pay the premium bid.

The practice is intended simultaneously to allow KNOC to offset costs, keep its reserves in circulation, and maintain a balance of stocks that reflect the present state of Korean consumption but fall short of acting as a revenue stream for the company.

KNOC also rents its spare storage capacity to foreign oil companies. Statoil stores more than 11 million bbl in KNOC's facilities as part of its Joint Oil Stockpiling program. KNOC developed this program to allow continued growth of oil stocks following the Asian financial crisis of 1998. The program provides moderate revenue in the form of rental fees and dictates that in the event of a supply crisis, Korea would enjoy a preferred right to purchase Statoil's stored stocks at market prices.

KNOC spends the money saved or earned from joint oil stockpiling and time swaps on expanding its reserve and occasionally comes under criticism for the cost-offsetting measures it employs in its stockpiling strategy. KNOC's system, however, has broadened the concept of strategic oil stockpiling by showing that stockpiled oil does not need to be static oil.

Crude stockpiling characteristics, lead indicators

Table 1

	Japan	US	Korea	China
Development cost	High	Medium	Medium	?
Size, days of forward cover	High	Low	Medium	?
Drawdown policy flexibility	Low	Medium	High	?
Economic efficiency	Low	Medium	High	?
2005 oil Imports, million b/d	5.1	13.5	2.3	3.3
2005 oil consumption, million b/d	5.36	20.66	2.31	6.98
2005 oil consumption change, %	1.4	–0.2	0.8	2.9

Source: BP Statistical Review of World Energy (June 2006)

Comparison

All oil-stockpiling systems share the goals of increasing oil supply security and minimizing the effects of supply disruptions by maintaining noncommercial oil reserves. The preceding descriptions, however, show that the world's first, second, and fourth-ranked importers of oil have employed dissimilar stockpiling strategies. Characteristics relevant to this discussion include cost of development, forward cover protection, drawdown policy, and economic efficiency.

Tradeoffs exist between security and efficiency. The US stockpile is the largest, but high demand means its SPR provides the fewest days of forward cover. Japan's high cost of development is partially attributable to Japan's vulnerability to natural disasters as well as to lack of salt cavern storage.

Table 1 sheds additional light on the contrasting conditions and motivations that underlie each stockpiling system.

Strategic oil stockpiling, like many energy issues, represents a confluence of geopolitical and economic interests. None of the three systems represented is extreme. Despite KNOC's cost-saving measures, oil stockpiles do not approach independent commercial feasibility. Even though massive Japanese reserves are hardly ever accessed, their existence inspires both national and global confidence in the oil market.

But large and readily identifiable cost differences exist among the different systems. The Korean approach places a smaller burden on both the Korean government and the global oil market. At the same time, however, no evidence exists that in a situation of global supply disruption, the Korean system would under perform its Japanese or American counterparts. KNOC's relatively frequent drawdown and bidding procedures actually may facilitate smooth operation during a crisis.

This thread of analysis seems to show the superiority of Korea's stockpiling system. Some experts and policymakers in China and elsewhere, however, disagree.

Analysis

Nominal oil prices at unprecedented highs and the global spotlight trained on China's oil demand leave it little room for error in development of its oil stockpiles. Chinese sentiment currently favors Japan's model, even as Japan plans to reform its system. Imitating Japan's system, however, would be a mistake. China would be better off developing a flexible system, suited to its own unique economic, political, and strategic conditions.

This analysis finds no problem with Phase I of China's stockpiling plan. The 100 million bbl stowed near import terminals and refineries will form the foundation of China's strategic reserves.

As China's import requirements continue to rise, however, stockpiling poses two challenges:

- Moderating any increase in dependence on imports.
- Avoiding price increases caused by importing barrels for stockpiling.

Filling its petroleum reserves will add 100,000-150,000 b/d to Chinese

demand for years to come.

In order to keep up with increasing demand, China should expand its government reserves to maintain at least 50 days of forward cover, market conditions permitting. At current price levels, however, the per-barrel cost of these stocks will far exceed money spent in the past by Japan, South Korea, and the US in the development of their reserves. Building reserves as expansive and inflexible as in Japan or the US could be too costly. China should instead invest in a comfortable cushion of government stocks and augment them with more innovative measures.

The unique relationship between the Chinese government and its major oil companies could play to China's advantage in developing reserves. The US and IEA oppose private strategic stockpiles because they fear that in an emergency, profit-maximizing companies may not share their government's interest in protecting the domestic economy.

China, however, could take advantage of existing commercial storage capacity by requiring its state-run oil importers to hold 40 days of forward cover in a mix of crude oil and refined products, thereby achieving the goal of the IEA-mandated 90 days cover. These reserves, already in the hands of distributors, would serve as China's first line of defense.

The Strategic Oil Stockpiles Office also could exercise flexibility in managing such "private" stocks, imitating KNOC by permitting companies to swap oil and to take advantage of seasonal price fluctuations.

Alternative stockpiling strategies could help complement China's reserves. The Korean Joint Oil Stockpiling program is one example. The possibility of reaching agreements with producers to store their oil in China for release under certain predefined tight supply scenarios would be another. ✦

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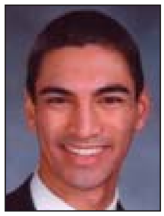

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Three new technologies for onshore, offshore operations

Three new technologies are available that complement WesternGeco Q-Technology services: WesternGeco DSC dynamic spread control for offshore surveys and the new Desert Explorer DX-80 vibroseis unit and MD Sweep for onshore operations.

DSC dynamic spread control is a new automated vessel, source, and streamer steering technology. It enables repeatability for 4D time-lapse studies and helps increase accuracy in Q enabled over-under and rich and wide azimuth surveys, the firm says. The Q-Marine technology platform, consisting of steerable streamers, single-sensor acquisition, dense acoustic positioning network, and calibrated marine sources, continues to evolve with the addition of the DSC system.

The Desert Explorer DX-80 vibroseis unit has been specifically developed to complement the Q-Land integrated acquisition and processing system. This vibroseis unit generates an 80,000 lb peak hydraulic force with low distortion across a broad bandwidth.

The new MD Sweep design methodology enables a vibrator to produce more energetic low frequencies than a traditional sweep design approach, the firm notes.

The suite of advanced geophysical services includes electromagnetic services and Q-Technology single-sensor high-fidelity seismic acquisition-to-inversion platform.

Source: **Schlumberger Ltd.**, 5599 San Felipe, 17th Floor, Houston, TX 77056.

New standardized dry chlorine scrubber

The new EST dry emergency chlorine scrubber, Type DES 3000, is a standardized, 1-ton system designed to mitigate accidental chlorine gas releases in accordance with Uniform Fire Code requirements.

It offers a safe, user friendly, and low-maintenance alternative to wet scrubbers and features lower long-term maintenance and operating costs than traditional wet scrubber systems, the company says.

The unit is preengineered and available for shipment in 8-10 weeks. A variety of custom configurations also is available.

The DES 3000 has a room exhaust rate of 3,000 cfm and has only one moving part—the fan. Type STS dry pellet media used in the DES 3000 system is landfill disposable and nonhazardous in the fresh and spent forms.

If not exposed to chlorine, the Type STS media has an indefinite life expectancy. As a result, dry media replacement and disposal costs over a 20-year operational period, assuming complete media exhaustion, are as low as half of the cost for caustic solution used in wet scrubbers, the firm points out.

Dry chlorine scrubbers do not require liquid chemical leak containment or double wall vessel construction, and they operate at subzero temperatures without the use of heaters.

Source: **Severn Trent Services**, Suite 300, Fort Washington, PA 18951.

Team Energy Resources Ltd.

Norwich, UK, has announced a merger with the manpower services arm of Aquatic Engineering & Construction, another Acteon company. The consolidated organization will operate under the existing Team Energy Resources name, and will provide personnel for drilling, completions and intervention, pipeline and process, and subsea and inspection. The new company will operate from offices in Aberdeen and Norwich, UK, and Doha, Qatar.

Aquatic's powered reeling systems business for laying and retrieving pipes and umbilicals will continue to operate under the Aquatic Engineering & Construction name.

ABB

Norwalk, Conn., has appointed Enrique Santacana as region manager for ABB North America and president and CEO of ABB Inc. USA.

Santacana holds a BS degree in electrical engineering from the University of Puerto Rico, a master of engineering degree from Rensselaer Polytechnic Institute, and an MBA from Duke University. He joined ABB in 1977, and has held a number of positions with the company, most recently serving as region division manager for power products in North America.

ABB is a leading provider of power and automation technologies.

M-I Swaco

Houston, has announced the opening of a facility in Bangkok to offer training in fluids and environmental solutions. The facility has been recognized as a valid training institution by the Technical Petroleum Training Institute arm of the Thailand Department of Minerals and Fuels.

M-I Swaco is a leading supplier of drilling, reservoir drill-in, completion fluids, and production chemicals products and systems for the global petroleum industry. The company is jointly owned by Smith International Inc. and Schlumberger Ltd.

Petris Technology Inc.

Houston, has announced its acquisition of the software and support assets of Production Access Inc. With the PA suite, Petris strengthens its application and data management footprint, which now includes geoscience, drilling, production, and pipelines.

Petris Technology Inc. provides IT-based solutions for energy clients, with expertise in data management, application hosting, GIS, and professional services.

Texas Onshore Resources Inc.

Houston, has announced the hiring of Lowell K. Lischer as the company's president. Lischer had been a geological consultant for Texas Onshore prior to being retained as head of US operations. He earned BS and MS degrees from the University of Missouri, and has over 33 years of oil and gas industry experience. His career includes stints with Chevron Oil Co., Marathon Oil Co., Moxa Energy Corp., True Oil Co., and Abraxas Petroleum Corp.

Texas Onshore Resources Inc. is a wholly owned subsidiary of privately held Swedish company, Texas Onshore AB.

Imports of crude and products

	Districts 1-4 7-6 2007	Districts 1-4 6-29 2007	District 5 7-6 2007	District 5 6-29 2007	Total US 7-6 2007	Total US 6-29 2007	Total US *7-7 2006
	1,000 b/d						
Total motor gasoline	1,281	1,276	142	116	1,423	1,392	1,099
Mo. gas. blending comp.	852	856	57	37	909	893	731
Distillate	238	303	40	10	278	313	338
Residual	428	251	0	0	428	251	295
Jet fuel-kerosine	48	134	257	159	305	293	225
Propane-propylene	224	130	1	7	225	137	169
Other	364	465	62	17	426	482	792
Total products	**3,435**	**3,415**	**559**	**346**	**3,994**	**3,761**	**3,649**
Total crude	**8,926**	**9,561**	**1,099**	**1,217**	**10,025**	**10,778**	**9,619**
Total imports	**12,361**	**12,976**	**1,658**	**1,563**	**14,019**	**14,539**	**13,268**

*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

	*7-13-07	*7-14-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	92.25	88.07	4.18	4.7
Brent crude	77.29	74.16	3.13	4.2
Crack spread	14.96	13.92	1.05	7.5
FUTURES MARKET PRICES				
One month				
Product value	93.38	90.80	2.58	2.8
Light sweet crude	72.80	75.29	–2.49	–3.3
Crack spread	20.58	15.51	5.07	32.7
Six month				
Product value	87.66	87.40	0.26	0.3
Light sweet crude	73.40	77.79	–4.39	–5.6
Crack spread	14.26	9.62	4.64	48.3

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

Purvin & Gertz LNG netbacks—July 13, 2007

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.16	4.40	5.63	4.30	4.99	5.60
Everett	5.20	3.13	4.82	3.22	3.70	5.50
Isle of Grain	4.44	2.27	3.98	2.12	2.96	3.90
Lake Charles	3.87	2.06	3.62	2.21	2.44	4.48
Sodegaura	4.77	6.89	4.97	6.60	5.93	4.23
Zeebrugge	5.65	3.67	5.04	3.60	4.14	5.06

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

Crude and product stocks

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	16,600	54,533	25,131	10,961	45,143	15,025	3,705
PADD 2	69,508	49,747	16,351	6,294	28,766	1,154	18,116
PADD 3	195,316	64,195	27,545	14,017	33,088	13,709	22,289
PADD 4	14,446	6,162	1,944	445	3,098	317	[1]1,680
PADD 5	56,710	30,939	20,921	9,441	12,275	5,294	—
July 6, 2007	**352,580**	**205,576**	**91,892**	**41,158**	**122,370**	**35,499**	**45,790**
June 29, 2007	**354,042**	**204,433**	**90,360**	**40,619**	**121,610**	**34,845**	**43,911**
July 7, 2006[2]	**335,316**	**212,651**	**92,039**	**39,847**	**129,899**	**41,733**	**51,342**

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

Refinery report—July 6, 2007

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,536	1,531	1,920	94	450	131	84
PADD 2	3,207	3,188	2,120	222	872	52	189
PADD 3	7,726	7,656	3,317	717	1,979	337	710
PADD 4	597	591	310	25	195	14	[1]156
PADD 5	2,663	2,595	1,562	419	514	147	—
July 6, 2007	**15,729**	**15,561**	**9,229**	**1,477**	**4,010**	**681**	**1,139**
June 29, 2007	**15,704**	**15,544**	**9,402**	**1,463**	**4,010**	**613**	**1,157**
July 7, 2006[2]	**15,734**	**15,496**	**9,176**	**1,453**	**4,352**	**558**	**1,071**
	17,443 operable capacity		**90.2% 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 7-11-07	Pump price* 7-11-07	Pump price 7-12-06
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	258.9	298.6	293.6
Baltimore	253.7	295.6	300.6
Boston	247.4	289.3	294.6
Buffalo	239.3	299.4	304.5
Miami	250.2	300.5	307.6
Newark	251.4	284.3	292.6
New York	240.2	300.3	302.6
Norfolk	250.9	288.5	295.6
Philadelphia	251.0	301.7	308.6
Pittsburgh	239.9	290.6	293.5
Wash., DC	260.0	298.4	313.6
PAD I avg	249.4	295.2	300.7
Chicago	261.1	312.0	325.6
Cleveland	220.5	266.9	285.6
Des Moines	250.2	290.6	273.6
Detroit	262.7	311.9	289.6
Indianapolis	254.6	299.6	282.6
Kansas City	249.2	285.2	273.6
Louisville	261.1	298.0	290.6
Memphis	252.0	291.8	285.5
Milwaukee	246.2	297.5	289.6
Minn.-St. Paul	239.3	279.7	280.6
Oklahoma City	245.5	280.9	265.6
Omaha	269.2	315.6	279.6
St. Louis	262.9	298.9	263.7
Tulsa	246.5	281.9	262.6
Wichita	248.1	291.5	271.6
PAD II avg	251.3	293.5	281.3
Albuquerque	256.3	292.7	285.6
Birmingham	246.1	284.8	280.6
Dallas-Fort Worth	247.0	285.4	290.6
Houston	245.4	283.6	289.6
Little Rock	245.4	285.6	279.6
New Orleans	251.0	289.4	284.6
San Antonio	243.3	281.7	275.6
PAD III avg	247.8	286.2	283.7
Cheyenne	258.7	291.1	275.5
Denver	270.8	311.2	295.5
Salt Lake City	270.2	313.1	300.5
PAD IV avg.	266.6	305.1	290.5
Los Angeles	253.8	312.3	339.5
Phoenix	264.7	302.1	311.5
Portland	266.9	310.2	305.6
San Diego	265.0	323.5	346.5
San Francisco	262.1	320.6	344.5
Seattle	248.9	301.3	322.6
PAD V avg.	260.2	311.7	328.4
Week's avg.	**252.6**	**296.1**	**294.2**
June avg.	**265.9**	**309.4**	**288.4**
May avg.	**264.1**	**307.6**	**288.5**
2007 to date	**225.6**	**269.2**	—
2006 to date	**213.9**	**257.0**	—

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

REFINED PRODUCT PRICES

Spot market product prices

	7-6-07 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	226.87
Gulf Coast	227.24
Los Angeles	229.24
Amsterdam-Rotterdam-Antwerp (ARA)	214.72
Singapore	209.62
Motor gasoline (Reformulated-regular)	
New York Harbor	237.49
Gulf Coast	234.99
Los Angeles	243.24

	7-6-07 ¢/gal
Heating oil No. 2	
New York Harbor	209.10
Gulf Coast	205.32
Gas oil	
ARA	204.97
Singapore	202.86
Residual fuel oil	
New York Harbor	134.83
Gulf Coast	135.05
Los Angeles	145.11
ARA	129.09
Singapore	140.16

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

BAKER HUGHES RIG COUNT

	7-13-07	7-14-06
Alabama	5	6
Alaska	8	8
Arkansas	50	25
California	38	30
Land	37	27
Offshore	1	3
Colorado	112	93
Florida	1	0
Illinois	0	0
Indiana	4	0
Kansas	15	14
Kentucky	11	6
Louisiana	182	189
N. Land	60	59
S. Inland waters	11	17
S. Land	46	33
Offshore	65	80
Maryland	1	0
Michigan	1	2
Mississippi	15	8
Montana	20	22
Nebraska	0	0
New Mexico	85	91
New York	5	6
North Dakota	36	31
Ohio	13	6
Oklahoma	186	188
Pennsylvania	11	17
South Dakota	4	1
Texas	837	748
Offshore	9	10
Inland waters	0	4
Dist. 1	23	23
Dist. 2	26	25
Dist. 3	66	64
Dist. 4	89	68
Dist. 5	176	136
Dist. 6	126	106
Dist. 7B	36	42
Dist. 7C	55	39
Dist. 8	110	93
Dist. 8A	27	30
Dist. 9	35	37
Dist. 10	59	71
Utah	38	41
West Virginia	32	27
Wyoming	69	105
Others—NV-4; TN-5; VA-2; WA-1	12	4
Total US	**1,791**	**1,668**
Total Canada	**360**	**571**
Grand total	**2,151**	**2,239**
Oil rigs	284	296
Gas rigs	1,501	1,368
Total offshore	76	94
Total cum. avg. YTD	**1,748**	**1,584**

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	7-13-07 Rig count	7-13-07 Percent footage*	7-14-06 Rig count	7-14-06 Percent footage*
0-2,500	56	7.1	56	3.5
2,501-5,000	103	53.3	95	41.0
5,001-7,500	247	24.2	213	18.7
7,501-10,000	419	3.1	374	2.9
10,001-12,500	458	1.9	396	2.0
12,501-15,000	272	—	278	—
15,001-17,500	107	—	106	—
17,501-20,000	67	—	80	—
20,001-over	38	—	21	—
Total	**1,767**	**7.9**	**1,619**	**6.1**
INLAND	42		40	
LAND	1,660		1,506	
OFFSHORE	65		73	

*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]7-13-07	[2]7-14-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	769	731
California	669	681
Colorado	51	61
Florida	7	7
Illinois	32	28
Kansas	96	98
Louisiana	1,366	1,351
Michigan	15	14
Mississippi	50	49
Montana	93	99
New Mexico	165	158
North Dakota	107	111
Oklahoma	167	172
Texas	1,337	1,353
Utah	45	48
Wyoming	145	130
All others	60	74
Total	**5,194**	**5,186**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	7-13-07
Alaska-North Slope 27°	57.84
South Louisiana Sweet	77.75
California-Kern River 13°	64.40
Lost Hills 30°	72.45
Southwest Wyoming Sweet	69.43
East Texas Sweet	70.00
West Texas Sour 34°	63.65
West Texas Intermediate	70.50
Oklahoma Sweet	70.50
Texas Upper Gulf Coast	67.25
Michigan Sour	63.50
Kansas Common	69.50
North Dakota Sweet	66.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	7-6-07
United Kingdom-Brent 38°	72.75
Russia-Urals 32°	69.85
Saudi Light 34°	68.73
Dubai Fateh 32°	67.52
Algeria Saharan 44°	74.96
Nigeria-Bonny Light 37°	75.63
Indonesia-Minas 34°	72.15
Venezuela-Tia Juana Light 31°	69.05
Mexico-Isthmus 33°	68.94
OPEC basket	71.00
Total OPEC[2]	70.15
Total non-OPEC[2]	69.62
Total world[2]	69.91
US imports[3]	67.65

[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]

	7-6-07	6-29-07	Change
		bcf	
Producing region	896	867	29
Consuming region east	1,348	1,278	70
Consuming region west	383	376	7
Total US	**2,627**	**2,521**	**106**
	Apr. 07	**Apr. 06**	**Change, %**
Total US[2]	**1,720**	**1,945**	**–11.6**

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

World oil balance

	-2007- 1st qtr.	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	-2005- 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.07	21.00	21.13	20.86	20.73	21.14
Canada	2.36	2.26	2.27	2.14	2.21	2.33
Mexico	2.08	2.03	1.99	2.02	2.08	2.10
Japan	5.45	5.35	4.81	4.78	5.96	5.46
South Korea	2.34	2.30	2.02	2.03	2.28	2.23
France	1.98	1.96	1.95	1.89	2.10	1.96
Italy	1.67	1.69	1.66	1.63	1.86	1.78
United Kingdom	1.79	1.80	1.76	1.81	1.90	1.84
Germany	2.41	2.70	2.74	2.58	2.59	2.63
Other OECD Europe	7.30	7.42	7.39	7.17	7.36	7.49
Australia & New Zealand	1.09	1.11	1.07	1.06	1.06	1.10
Total OECD	**49.54**	**49.62**	**48.79**	**47.97**	**50.13**	**50.06**
NON-OECD						
China	7.47	7.33	7.25	7.34	6.97	7.07
FSU	4.66	4.57	4.34	4.39	4.57	4.66
Non-OECD Europe	0.74	0.70	0.65	0.69	0.74	0.69
Other Asia	8.52	8.73	8.42	8.51	8.43	8.89
Other non-OECD	14.58	14.48	14.69	14.42	14.20	15.02
Total non-OECD	**35.97**	**35.81**	**35.35**	**35.35**	**34.91**	**36.33**
TOTAL DEMAND	**85.51**	**85.43**	**84.14**	**83.32**	**85.04**	**86.39**
SUPPLY						
OECD						
US	8.43	8.46	8.48	8.35	8.18	7.74
Canada	3.40	3.40	3.32	3.16	3.29	3.28
Mexico	3.59	3.52	3.71	3.79	3.80	3.75
North Sea	4.80	4.76	4.51	4.71	5.11	5.05
Other OECD	1.49	1.52	1.52	1.41	1.41	1.51
Total OECD	**21.71**	**21.66**	**21.54**	**21.42**	**21.79**	**21.33**
NON-OECD						
FSU	12.58	12.45	12.23	12.03	11.78	11.97
China	3.84	3.83	3.83	3.85	3.83	3.75
Other non-OECD	11.44	11.67	11.87	11.67	11.49	11.75
Total non-OECD, non-OPEC	**27.86**	**27.95**	**27.93**	**27.55**	**27.10**	**27.47**
OPEC*	**34.52**	**35.94**	**36.62**	**36.16**	**36.33**	**36.70**
TOTAL SUPPLY	**84.09**	**85.55**	**86.09**	**85.13**	**85.22**	**85.50**
Stock change	**–1.42**	**0.12**	**1.95**	**1.81**	**0.18**	**–0.89**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD total net oil imports

	Mar. 2007	Feb. 2007	Jan. 2007	Mar. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,241	–1,333	–1,340	–1,304	63	–4.8
US	12,634	10,795	12,145	11,711	923	7.9
Mexico	–1,673	–1,726	–1,601	–1,938	265	–13.7
France	1,311	1,960	1,694	2,086	–775	–37.2
Germany	2,139	2,358	2,166	2,356	–217	–9.2
Italy	1,650	1,714	1,638	1,634	16	1.0
Netherlands	815	1,009	1,151	851	–36	–4.2
Spain	1,488	1,670	1,509	1,646	–158	–9.6
Other importers	3,720	4,056	3,973	3,844	–124	–3.2
Norway	–2,476	–2,395	–2,673	–2,654	178	–6.7
United Kingdom	171	–165	104	55	116	210.9
Total OECD Europe	**8,818**	**10,207**	**9,562**	**9,818**	**–1,000**	**–10.2**
Japan	5,013	5,382	5,573	6,396	–1,383	21.6
South Korea	2,615	2,087	2,349	2,006	609	30.4
Other OECD	1,020	792	760	1,077	–57	–5.3
Total OECD	**27,186**	**26,204**	**27,448**	**27,766**	**–580**	**–2.1**

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

OECD* total gross imports from OPEC

	Mar. 2007	Feb. 2007	Jan. 2007	Mar. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	380	304	549	407	–27	–6.6
US	6,296	5,342	6,093	5,659	637	11.3
Mexico	28	23	17	16	12	75.0
France	534	821	792	757	–223	–29.5
Germany	330	351	434	415	–85	–20.5
Italy	1,230	1,316	1,312	1,153	77	6.7
Netherlands	576	638	88	710	–134	–18.9
Spain	627	797	700	851	–224	–26.3
Other importers	953	1,465	1,256	1,147	–194	–16.9
United Kingdom	248	251	166	110	138	125.5
Total OECD Europe	**4,498**	**5,639**	**4,748**	**5,143**	**–645**	**–12.5**
Japan	4,788	4,382	4,433	5,254	–466	–8.9
South Korea	2,485	2,080	2,294	2,054	431	21.0
Other OECD	706	700	754	614	92	15.0
Total OECD	**19,181**	**18,470**	**18,888**	**19,147**	**34**	**0.2**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Mar. 2007	Feb. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	727	555	691	523	168	32.1
Angola	708	464	586	477	109	22.9
Kuwait	305	168	217	115	102	88.7
Nigeria	1,346	1,102	1,198	1,249	–51	–4.1
Saudi Arabia	1,244	1,207	1,342	1,393	–51	–3.7
Venezuela	1,285	1,359	1,277	1,516	–239	–15.8
Other OPEC	681	487	618	93	525	564.5
Total OPEC	**6,296**	**5,342**	**5,929**	**5,366**	**563**	**10.5**
Canada	2,305	2,448	2,407	2,276	131	5.8
Mexico	1,749	1,507	1,611	1,823	–212	–11.6
Norway	164	131	133	205	–72	–35.1
United Kingdom	292	268	251	231	20	8.7
Virgin Islands	349	312	363	297	66	22.2
Other non-OPEC	2,740	2,159	2,570	3,061	–461	–16.0
Total non-OPEC	**7,599**	**6,825**	**7,335**	**7,893**	**–558**	**–7.1**
TOTAL IMPORTS	**13,895**	**12,167**	**13,264**	**13,259**	**5**	**—**

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

Oil stocks in OECD countries*

	Mar. 2007	Feb. 2007	Jan. 2007	Mar. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	179	188	186	196	–17	–8.7
Germany	291	292	285	280	11	3.9
Italy	134	135	128	132	2	1.5
United Kingdom	106	105	105	97	9	9.3
Other OECD Europe	657	674	675	651	6	0.9
Total OECD Europe	**1,367**	**1,394**	**1,379**	**1,356**	**11**	**0.8**
Canada	177	176	183	170	7	4.1
US	1,677	1,666	1,723	1,692	–15	–0.9
Japan	615	631	638	620	–5	–0.8
South Korea	156	147	153	137	19	13.9
Other OECD	101	103	105	103	–2	–1.9
Total OECD	**4,093**	**4,117**	**4,181**	**4,078**	**15**	**0.4**

*End of period.
Source: DOE International Petroleum Monthly Report
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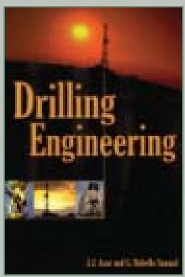

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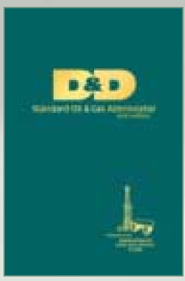

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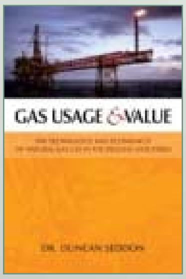

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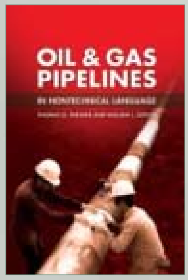

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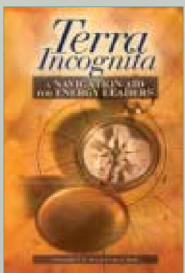

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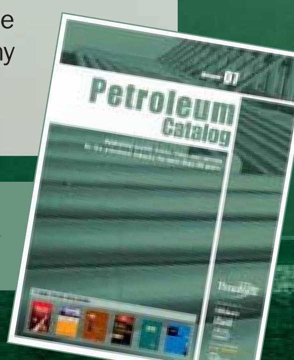

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Beer price hikes will underscore US energy folly

The Editor's Perspective

by Bob Tippee, Editor

Because Americans are awakening to folly, House Republicans should be careful how they criticize their Democratic colleagues about energy.

Republicans complained to reporters on July 11 that Democrats have been too slow to act on the subject.

"They failed to produce a comprehensive plan in the first 6 months of the year," growled House Republican Chairman Adam Putnam of Florida (OGJ Online, July 12, 2007).

Marsha Blackburn of Tennessee went on to assert that "the public expects us to address our rising energy costs, but this [the Democratic] bill does none of that."

Whoa. Comprehensive plan? Congressional solutions to rising energy costs?

Such meddling by government creates problems. Republicans should be calling for less of it.

The Energy Policy Act of 2005, passed while Republicans controlled Congress, is an example.

While opening little of the vast federal acreage that the US ludicrously excludes from oil and gas development, the comprehensive law addressed rising energy costs by mandating the use of subsidized ethanol and creating generous incentives for other costly forms of energy.

One of the predicted consequences of the ethanol mandate is becoming painfully evident: rising food prices.

The ethanol industry insists that energy, not corn, costs are lifting food prices.

While energy surely affects food prices, ethanol's contribution can't be so easily dismissed. Unlike the demand growth pushing up energy prices, the new demand for corn is an act of Congress. So are the price effects. There's no way to deny this (OGJ, July 9, 2007, p. 76).

Furthermore, ethanol aggravates the energy-price rise that its supporters cite, in part through the incremental rail and truck transport needed to move the material from scattered plants to blending locations.

Public grumbling has begun about the food-price jumps that accompany ethanol's growth. It soon will turn serious.

USA Today reported July 2 that the price of beer is set to leap because farmers are planting corn in fields once dedicated to barley. Prices of the beer ingredient are rising.

If the prospect of jumping beer prices doesn't focus American attention to the harm Congress does with politically motivated energy mistakes, nothing will.

(Online July 13, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

US crude tops $73/bbl, may head higher

After testing price barriers during intraday trading for five consecutive sessions, the near-month benchmark US crude contract closed above $73/bbl in New York on July 13, and analysts said it could be headed higher this summer.

The August contract for benchmark US light, sweet crudes touched an 11-month intraday high of $74.01/bbl July 13 before closing at $73.93/bbl, up $1.43 for the day on the New York Mercantile Exchange. That same day in London, speculators pushed North Sea Brent crude to an 11-month high of $77.70 in intraday trading via the IntercontinentalExchange Inc.—less than $1 short of the all-time high of $78.65/bbl last August—on reports of production problems in the North Sea and forecasts of rising demand.

As the August crude contract surged past $74/bbl in early trading July 16 before NYMEX opened, analysts at the Société Générale Group said US oil prices were "shifting to the left, now centered beyond $74/bbl."

Having punched through the $73/bbl level, the front-month crude contract may possibly climb to $75/bbl on New York commodity market, said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. He noted that benchmark US crude prices continued to rise "for a fifth week in a row with a maintained momentum bringing $75/bbl within reach and searching for the highs of last year." He said market dynamics remained "in a very strong technical momentum but still in overbought territory."

Earlier, Jakob said the "impressive" speculative assault for higher crude prices "will need to have the support of the products" market to be sustained. He said, "European simple refinery margins are already in the red and if the trend of rising Brent and falling gasoline [prices] was to continue, then the European complex refining margins will start to also be under serious pressure."

Adam Sieminski, chief energy economist, Deutsche Bank AG, New York, said his bank raised its price forecast for West Texas Intermediate and Brent crude to an average $60/bbl in 2010. "This compares with our prior $45/bbl estimate for both benchmarks and an average of $20/bbl in the 1990s," he said. "US natural gas prices are forecast to average $8/MMbtu in 2010, up from a prior $7/MMbtu."

Sieminski said, "A key justification for this move is that finding and development costs are rising rapidly and these are expected to rise further over the next few years. Moreover, geopolitical challenges to supply are also deteriorating, at least for now. Demand has not been as responsive to higher energy prices due to the growth in real incomes. Plausible substitutes for oil and gas are expensive. The timeframe for inducing the changes that could bring oil and natural gas prices down is getting longer."

IEA sees more demand

In its weekly report issued July 13, the International Energy Agency in Paris said Brent futures prices surged past $77/bbl in mid-July because of tight market fundamentals, increased geopolitical tension in some major oil producing countries, and indications of strong buying of petroleum futures by investment funds. "Falling refining margins suggest that market tightness is shifting from product to crude markets," IEA officials said.

IEA expects global demand for petroleum products to rise by a robust 2.5% to 88.2 million b/d in 2008, due to a weather-related rebound in the Organization for Economic Cooperation and Development member countries and strong demand in non-OECD countries. "This represents an increase of 2.2 million b/d, from the slightly revised 2007 level of 86 million b/d," the agency said.

IEA sees production capacity of the Organization of Petroleum Exporting Countries increasing by 2 million b/d to an average 35.4 million b/d next year, with non-OPEC production increasing by 1 million b/d to 51 million b/d. "Key growth drivers include the former Soviet Union, Latin America, and global biofuels. OECD Europe and North America [will] continue to see production decline, despite strong growth from the US Gulf of Mexico and Canadian oil sands," IEA predicted.

Jakob said, however, "After over-estimating non-OPEC supply for many years, IEA is now over-estimating oil demand." He said, "The IEA has started to make downward revisions to 2007 oil demand but [is] still forecasting a 400,000 b/d demand growth in North America for the third quarter while the US Department of Energy is showing zero growth in the 4-week average; [it is] still forecasting demand growth for Europe in the third quarter when data released July 12 for Germany still shows demand down in June by 9.7%, Italy down by 2.9%, etc."

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