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Production Report

Task force: US can shrink oil gap with unconventional fuels

Recovery factors leave vast target for EOR technologies

Low C_3 inventory build fuels supply concerns for heating

Uncertainty-based assessment subs for internal inspection

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Nov. 5, 2007
Volume 105.41

Production Report

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More companies are evaluating or have started enhanced oil recovery projects for obtaining additional oil from mature fields. The cover shows part of Amal West field in Oman in which Petroleum Development Oman recently started steam injection in a pilot project. As described in the first two articles in the special report, starting on p. 49, PDO has numerous EOR projects either under construction or in the planning stage. Dubai Petroleum is another company in the Middle East that may begin EOR (p. 66). Photo by Guntis Moritis.

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General Interest — Quick Takes

Senate members question further SPR oil purchases

Noting that crude oil prices have reached the $90/bbl range, seven US Senate Democrats asked Energy Secretary Samuel W. Bodman on Oct. 18 to suspend further purchases for the Strategic Petroleum Reserve.

The US Department of Energy deposited 2.6 million bbl in the SPR during September and plans to buy another 6 million bbl in the next few months, said Energy and Natural Resources Committee Chairman Jeff Bingaman (NM) and six other Senate Democrats.

"This action sends a message to the marketplace that the administration is comfortable with current price levels, and can only add to US crude oil prices and the prices of related commodities," they said in a letter to Bodman.

The seven Senate Democrats also criticized DOE's issuing a solicitation Oct. 10 for 13 million bbl of crude from federal leases in the Gulf of Mexico under the royalty-in-kind program (OGJ Oct. 22, 2007, Newsletter). DOE said the action was in accordance with the 2005 Energy Policy Act, which directs that the SPR be filled to its authorized 1 billion bbl capacity. It added that there are no immediate plans to replace 11 million bbl of SPR crude which were sold in response to Hurricane Katrina.

DOE's policy of continuing to fill the reserve is bad for taxpayers as well as consumers, the lawmakers said. "Based on the department's own forecasting of crude oil prices and on current futures prices, a deferral of SPR deliveries for 12 months would allow the department to acquire the oil at a discount of more than $10/bbl compared to today's prices," they said.

In addition to Bingaman, Sens. Byron L. Dorgan (ND), John F. Kerry (Mass.), Carl M. Levin (Mich.), Claire McCaskill (Mo.), Jack Reed (RI), and Ron Wyden (Ore.) signed the letter.

NEB: Canadian oil, gas stocks adequate' for winter

Supplies of heating oil and natural gas will be adequate for this winter, Canada's National Energy Board reported.

Even with a winter that is colder-than-usual, high storage levels of gas will be more than adequate to meet heating demand, NEB said in its winter outlook for Canada's energy markets.

The price for heating oil should track similarly to the price of crude, which will likely remain in the $75-80/bbl range throughout the winter, NEB said. Also, tightening supply inventories will continue to raise prices, it said.

North American gas futures prices are expected to hold steady between $6-8/MMbtu, NEB expects. Stronger gas production in the US as well as imported LNG will offset any decline in production from Canada.

In mid-October, oil prices crested to new record-highs, NEB said, driven by a combination of market speculation, Middle East political tensions, the low US dollar, and persistent refinery bottlenecks. The Organization of the Petroleum Exporting Countries agreed in September to raise its supply output by 500,000 b/d, starting in November. NEB said this supply increase should help to moderate recent high oil prices.

It added that despite high crude prices, Canadian consumers are not likely to see high prices at gasoline pumps until spring, as the high driving season, Apr. 1 to Labor Day, increases demand for gas.

MMS sells more than 91 bcf of RIK gas

The US Minerals Management Service sold more than 91 bcf of natural gas it received from Gulf of Mexico offshore producers as royalties in kind to nine high bidders, the Department of Interior agency said Oct. 23.

The gas will be delivered in 13 sales packages over 5-12 months beginning Nov. 1 to 13 offshore pipeline systems originating in the gulf, MMS said. Bear Energy LP, BG Energy Merchants, ConocoPhillips Inc., Louis Dreyfus Energy Services, National Energy and Trade LP, PPM Energy Inc., Sequent Energy Management LP, United Energy Trading LLC, and Williams Trading Co. submitted the winning bids.

Bidding was strong for the sale as 21 companies tendered 175 offers for the gas, MMS Director Randall Luthi said. Revenues would total $641 million at current prices, although actual revenues will vary based on prices over the life of the contracts, he added.

The gas in the sale was taken as royalties in kind instead of cash payments from federal Gulf of Mexico leases. MMS then sells such gas competitively on the open market. It has said that the program is more efficient, reduces regulatory and reporting costs, provides early certainty to royalty values, and ensures a fair return on public royalty assets.

House Natural Resources Committee Chairman Nick J. Rahall (D-W.Va.) has criticized the program and attempted to impose limits on its use in legislation which the committee passed last spring.

Luthi said MMS will continue to use royalty-in-kind sales in tandem with royalty-in-value, or cash, payments depending on the particular business case to ensure a fair return on public royalty assets.

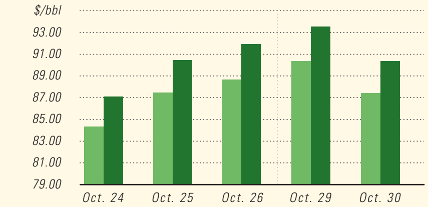
China's oil production, imports rise during 2007

This year China has imported 18.1% more oil during January-August than it did in the comparable period last year, according to figures published by the country's General Administration of Customs (GAC).

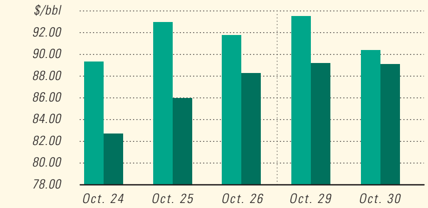
GAC said China's total oil imports were 110.4 million tonnes in

Industry Scoreboard

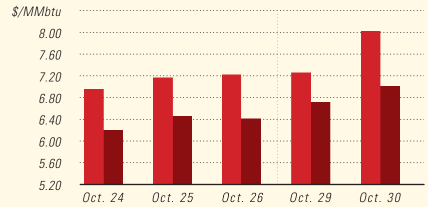
IPE BRENT / NYMEX LIGHT SWEET CRUDE



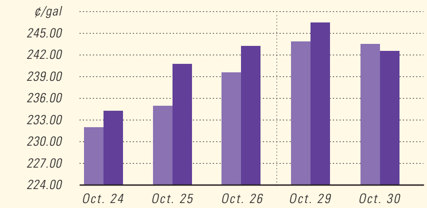
WTI CUSHING / BRENT SPOT



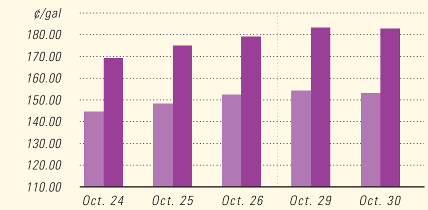
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



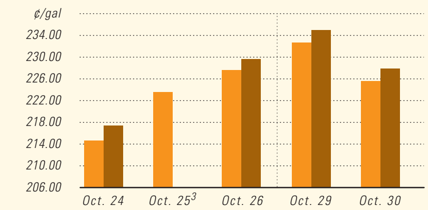
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



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

US INDUSTRY SCOREBOARD — 11/5

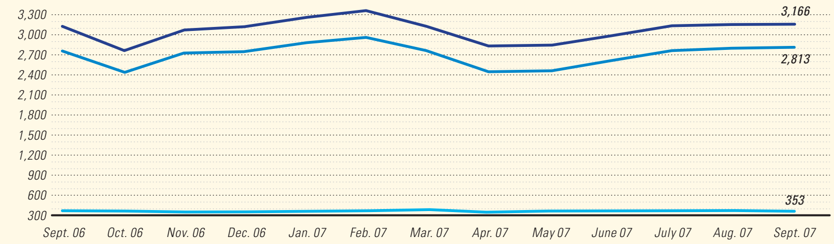
Latest week 10/19	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,237	9,256	–0.2	9,306	9,244	0.7
Distillate	4,295	4,253	1.0	4,215	4,151	1.5
Jet fuel	1,553	1,606	–3.3	1,619	1,636	–1.0
Residual	812	586	38.6	761	705	7.9
Other products	4,882	4,993	–2.2	4,820	4,872	–1.1
TOTAL DEMAND	20,779	20,694	0.4	20,721	20,674	0.2
Supply, 1,000 b/d						
Crude production	5,087	5,081	0.1	5,155	5,095	1.2
NGL production[2]	2,447	2,369	3.3	2,380	1,192	8.6
Crude imports	9,908	10,322	–4.0	10,006	10,192	–1.8
Product imports	3,498	3,415	2.4	3,517	3,700	–4.9
Other supply[3]	932	964	–3.3	997	1,084	–8.0
TOTAL SUPPLY	21,872	22,151	–1.3	22,055	22,263	–0.9
Refining, 1,000 b/d						
Crude runs to stills	15,082	15,413	–2.1	15,253	15,250	—
Input to crude stills	15,259	15,590	–2.1	15,496	15,610	–0.7
% utilization	87.5	89.6	—	88.9	89.8	—

Latest week 10/19	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	316,577	321,865	–5,288	332,345	–15,768	–4.7
Motor gasoline	193,837	195,768	–1,931	207,416	–13,579	–6.5
Distillate	134,471	136,318	–1,847	143,981	–9,510	–6.6
Jet fuel-kerosine	41,928	41,654	274	41,580	348	0.8
Residual	36,739	36,425	314	41,815	–5,076	–12.1
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	21.0	21.3	–1.4	22.1	–5.0	
Motor gasoline	21.0	21.3	–1.4	22.3	–5.8	
Distillate	31.3	32.1	–2.5	33.2	–5.7	
Propane	54.9	55.0	–0.2	65.5	–16.2	
Futures prices[5] **10/26**			**Change**		**Change**	**%**
Light sweet crude, $/bbl	88.67	88.27	0.40	60.47	28.20	46.6
Natural gas, $/MMbtu	7.01	7.34	–0.33	7.26	–0.26	–3.5

[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.

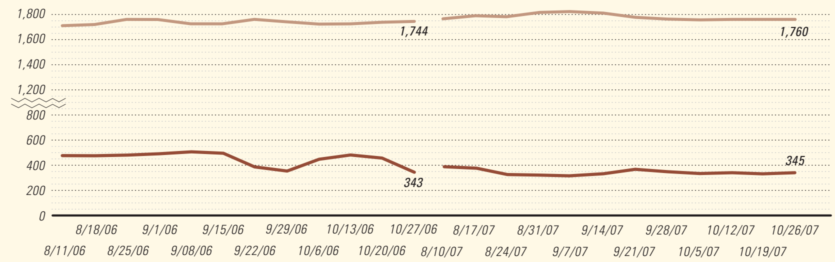
Sources: Energy Information Administration, Wall Street Journal

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

the first 8 months of this year; however, it exported 2.18 million tonnes, resulting in net imports of 108.22 million tonnes. Over the same period last year it imported 91.65 million tonnes of oil.

GAC also said domestic production of crude oil reached 124.7 million tonnes in the 8-month period, up 1.3% over last year.

China imported 24.28 million tonnes of oil products during the same period this year, GAC said. It produced domestically 129.08 million tonnes: 39.9 million tonnes of gasoline, up 8.8%; 7.68 million tonnes of kerosene, up 17.5%; and 81.5 million tonnes of diesel oil, up 6.3%. ✦

Exploration & Development — *Quick Takes*

MMS raises royalty for OCS Sales 206 and 224

The US government has raised the royalty rate on new offshore leases for the second time this year.

In proposals for Outer Continental Lease Sales 206, covering the Central Gulf of Mexico, and 224, covering the Eastern Gulf, the Minerals Management Service stipulates a royalty rate of 18.75%. The standard royalty has been 16.7%. The sales are scheduled Mar. 19, 2008.

Last January, MMS raised the royalty on new deepwater leases to 16.7% from 12.5% (OGJ, Jan. 15, 2007, p. 37).

MMS proposes to offer 5,000 blocks covering more than 28.5 million acres in the Central Gulf. Water depths of some blocks exceed 11,200 ft. Sale 206 covers the same area that Central Gulf Sale 205 did Oct. 3.

Sale 205 drew apparent high bids totaling more than $2.9 billion—the second highest total in US leasing history—for 723 tracts (OGJ, Oct. 15, 2007, Newsletter).

In Sale 224, MMS proposes to offer 118 whole or partial unleased blocks covering 547,230 acres in the Eastern Gulf. Water depths are 2,675-10,213 ft.

It would be the first offering of these Eastern Gulf blocks since 1988.

Apache tests more gas in Egypt's Western Desert

Houston independent Apache Corp. reported that its Jade-2x well in Egypt's Western Desert flowed on test 26.7 MMcfd of natural gas and 1,325 b/d of condensate from the Jurassic Alam El Bueib-6 (AEB) formation.

The well was the first test of the AEB reservoirs in the Jade structure along the Matruh Ridge, confirming AEB resource potential identified in the Jade-1x discovery in March. The Jade-1x discovery well logged 217 ft of AEB pay and 66 ft net pay in the Jurassic Upper Safa formation. The discovery was completed as a gas producer from the Upper Safa after a test of 25.6 MMcfd of gas (OGJ, Apr. 9, 2007, Newsletter).

The Jade-2x well, which is 1 mile northeast of Jade-1x, logged 148 ft of AEB pay.

Also at Jade field, the Jade-4 well has reached 12,670 ft TD and logged 234 ft of net pay in the AEB formation. The Jade-4, a twin to the Jade-1x and drilled to access the AEB sands identified in the discovery well, will be tested and completed following the Jade-2x test.

Apache recently recompleted the Imhotep-2 well to the AEB-6 zone which tested at a rate of 4,082 b/d of condensate and 3.3 MMcfd of gas. Imhotep field is 17 miles east southeast of Jade field. It was established in February 2004 as a Jurassic Upper Safa gas field, with cumulative production to date of 33 bcf of gas and 1.78 million bbl of associated condensate.

The AEB formation is one of the most prolific oil-producing reservoirs in the greater Khalda concession, accounting for almost 40% of the more than 250 million bbl total crude oil produced from the concession to date.

Apache holds a 100% contractor interest in the 250,000-acre Matruh concession. ✦

Drilling & Production — *Quick Takes*

ExxonMobil starts up Angola's Marimba North field

Esso Exploration Angola (Block 15) Ltd. has begun production from the Marimba North project in 3,900 ft of water 90 miles off Angola.

The Marimba North project, designed to develop 80 million bbl of oil, is a tie-back to the Kizomba A development and has come on stream ahead of schedule and within budget, and without any production impact to the Kizomba A operations.

The project includes subsea wells, a single drill center, 30 km of flowlines, and a unique riser system which ties the production flowline into the existing Kizomba A tension-leg platform. The Marimba North production and control facilities have been integrated with the existing Kizomba A development to effectively and cost efficiently use the existing field facilities.

Marimba North, one of seven major start-ups for ExxonMobil this year, will add about 40,000 b/d of peak production capacity to the existing Block 15 production, which includes the Xikomba, Kizomba A, and Kizomba B developments. With the addition of Marimba North, Block 15 will produce about 540,000 b/d of oil with combined estimated recoverable resources of 2 billion bbl of oil. A fourth Block 15 development, the Kizomba C project, is planned to develop an additional 600 million bbl in Mondo, Saxi, and Batuque fields.

Block 15 participants are Esso (operator) 40%, BP Exploration (Angola) Ltd. 26.67%, Eni Angola Exploration BV 20%, and Statoil Angola 13.33%.

SPD raises oil output in Siberia's Salym field

Salym Petroleum Development NV (SPD), a joint venture of Royal Dutch Shell PLC and Sibir Energy PLC, reported a record-high oil production rate at Salym field in the Khati-Mansi autonomous region of western Siberia.

Salym said the rate of production at Salym fields, which include West Salym, Upper Salym, and Vadelyp, exceeded 100,000 b/d one month ahead of schedule. An SPD spokesman said the production increase was due primarily to exploration of West Salym field.

SPD CEO Harry Brekelmans said SPD, which had doubled production in 16 months to 100,000 b/d from 50,000 b/d, has produced more than 22 million bbl of crude this year.

In 2004, SPD began oil production from wells in West Salym, the largest of the Salym group of oil fields in the region (OGJ Online, Dec. 23, 2004).

BPZ gets tankers, fast tracks Corvina production

BPZ Energy has signed two short-term contracts with the Peruvian Navy for two 6,000-bbl tankers to transport oil earlier than scheduled from Corvina oil and gas field on Block Z1 off northwestern Peru.

The field is expected to begin production of about 2,500 b/d of oil in early November. Last month it tested 8,300 b/d of oil and 184 MMcfd of gas, mostly from the Lower Miocene Upper Zorritos formation (OGJ Online, Oct. 10, 2007).

BPZ plans to ramp up production from 2,500 bo/d to 4,000 bo/d using two barges when they become available at yearend or early next year.

BPZ previously announced that two barges, the Nomoku and the Nu'uanu, each with a capacity of about 40,000 bbl, had been leased and would be used as floating production, storage, and offloading facility and transport barges in the company's oil production operations. These barges are currently being outfitted with equipment in the port of Paita, but have encountered some delays due to scheduling.

The Nomoku will be used as an FPSO, moored at the CX11 platform, while the Nu'uanu will be used to transport oil between offshore Corvina field and Petroperu SA's 62,000 b/cd Talara refinery, 70 miles south of the BPZ's operations.

PDVSA charters Neptune Discoverer drillship

Venezuela state firm Petroleos de Venezuela SA (PDVSA) signed a 4-year contract with Neptune Marine, Nicosia, to charter the Neptune Discoverer drillship.

The vessel will drill natural gas wells as part of the development of the Mariscal Sucre gas project under a contract lasting 1,460 days and valued at some $700 million.

Neptune Marine also will participate in a social welfare program together with PDVSA in Venezuela for a total of 8% of the day rate in the contract.

The drillship will deploy to Venezuela upon completion of its drilling commitment for Con Son in Vietnam, estimated at the end of November. The drillship is expected to reach Venezuelan waters toward the end of February 2008.

In September Venezuelan President Hugo Chavez said he wanted his country—which became a gas importer this month with the opening of a pipeline from Columbia—to increase gas production by 3 bcfd to 11 bcfd by 2011.

At the time, Chavez said his government is "launching the socialist gas revolution," claiming that Venezuela possesses "80% of South America's gas reserves" and "30% of the gas reserves in the Americas (OGJ Online, Sept. 19, 2007)." ✦

Processing — *Quick Takes*

CCRL plans to expand Saskatchewan refinery

Consumers' Cooperative Refineries Ltd. (CCRL) has retained International Alliance Group (IAG) as program manager for the grassroots portion of a proposed expansion of its 100,000 b/cd refinery in Regina, Sask.

The project would increase output of Saskatchewan's only oil refinery by 30%. It involves building a fluid catalytic cracking complex to support the additional crude oil processing.

IAG is expected to make a final decision in early 2008 to move forward with detailed design and construction of the project, which, if implemented, would increase capacity of the refinery to 130,000 b/cd.

Meanwhile, Mustang Engineering, a subsidiary of John Wood Group PLC, is providing front-end engineering design services to IAG for the CCRL refinery expansion.

Galp to expand Porto refinery in Portugal

Galp Energia SA has let a contract to Fluor Corp. for front-end engineering and design and early procurement services of main equipment for a conversion project at its 91,000 b/cd refinery in Porto, Portugal. The contract's value was not disclosed.

The conversion project will add a grassroots vacuum flash and distillation unit, a visbreaker, a diesel hydrodesulfurization unit, and associated utilities and infrastructure. The project is part of Galp's investment program to increase production of diesel by 50,000 b/d as well as the utilization rate of its existing refineries. The revamp also will enable Galp to process heavier crudes.

Fluor offices in Madrid and in Camberley, UK, will carry out the refinery conversion work along with local Portuguese companies.

Fluor previously constructed an HDS unit for Galp's 213,000 b/cd refinery at Sines in 2002.

Pertamina seeks oil supplies for planned refinery

Indonesia's state-owned PT Pertamina is seeking crude supplies from oil-producing countries to feed its refinery project in Bojonegara, Banten, after Iran reduced its supply commitment to 100,000 b/d from 300,000 b/d.

"The commitment with Iran is a fragile one, so we are looking for other sources to supply the crude," said Pertamina's director of refining Suroso Atmomartoyo. "We have to ensure we get the supplies before the refinery is completed."

Atmomartoyo said Pertamina is in talks with several countries for the crude supply, but he would not identify them, saying negotiations were still at the early stages.

Pertamina and Iran had signed a memorandum of understanding in March 2005 to jointly build the 300,000 b/d Banten refinery with the understanding that Iran would invest in the $5.6 billion refinery and supply the heavy crude.

In July, they agreed to build the refinery and said construction would start in 2008, with completion scheduled for 2012. Officials from the two countries planned an August meeting in Tehran to discuss project details, including equity distribution, project structure, and crude supply agreements.

However, in September Iran expressed disappointment with Indonesia's handling of the plan to build the refinery jointly, including the substitution of Pertamina for its 51.38%-owned subsidiary PT Elnusa to be partner with Iran's National Iranian Oil Refining & Distribution Co. in the project.

"The heads of state of the two countries made a commitment to support the development of the project, but after 3 years there is no progress toward its implementation," said Mahmoud R. Radboy, head of the economic section at the Iranian embassy in Jakarta.

At the same time, Pertamina Pres. Ari Hernanto Soemarno said implementation of the project would be postponed because of rising costs. ✦

Transportation — *Quick Takes*

Enbridge plans North Dakota pipeline expansion

Enbridge Energy Partners LP, Houston, said it will proceed with yet another expansion of the Enbridge North Dakota Pipeline System.

Costing an estimated $150 million, the expansion will add 40,000 b/d of capacity from the western end of the system to Minot, ND, and 51,000 b/d of capacity from there to Clearbrook, Minn.

It will increase total system capacity to 161,000 b/d from 110,000 b/d, with an in-service date of late 2009.

Enbridge said it will file with the US Federal Energy Regulatory Commission a cost-of-service-based expansion surcharge that will be added to existing tariff rates to fund the proposed expansion. No long-term volume commitments will be required for existing or new capacity.

This expansion is in addition to the existing 30,000 b/d expansion project that is under way and slated for completion by yearend.

The North Dakota Pipeline system gathers oil from production areas in western North Dakota and eastern Montana and transports it to Clearbrook, where the system interconnects with the Minnesota Pipeline and the Partnership's Lakehead System. From Lakehead, shippers can access most of the major refinery markets along the Great Lakes and in the Midwest.

Hammerfest LNG exports first cargo

The LNG carrier Arctic Princess and its cargo of 145,000 cu m of LNG has left the Norwegian Hammerfest liquefaction plant and is on its way to southern Europe. The launch marks Europe's first LNG export.

The gas came from Snohvit field in the Norwegian Barents Sea, with the first gas volumes produced in August and first LNG, in September. "The LNG production from Snohvit is still undergoing a run-in phase," said project partner RWE Dea AG. Stable production is expected to begin by yearend.

Carbon dioxide, accounting for 5% of the Snohvit well stream, is separated and injected into a different underground formation. The project has cost a total of €6.5 billion. At full production, carriers will leave port at Melkoya every 5-6 days. Each ship will transport nearly 150,000 cu m of gas as LNG to customers worldwide.

Snohvit has been developed by a consortium consisting of operator StatoilHydro 33.53%, Petoro 30%, Total E&P Norge 18.4%, Gaz de France 12%, Hess Norge 3.26%, and RWE Dea 2.81%.

Tangguh LNG partners ponder additional trains

BP PLC subsidiary BP Berau Ltd., operator of the Tangguh LNG project, is considering construction of as many as eight additional LNG trains at the company's existing site in Papua.

The company has set up a special team to study the possibility of new trains at the existing plant. Two other LNG trains are nearing completion.

"We are concentrating on getting these [two trains] finished. We are also looking at further development and opportunities for building more trains," said David Clarkson, the project's executive vice-president.

BP began construction of the two trains in March 2005, with the first due to go online in January 2009 and the second in May 2009. The project is said to be 82% complete as of September.

Tangguh will sell LNG to four overseas buyers—China's Fujian (2.6 million tonnes/year), South Korean K-Power and Posco (1.11 million tpy each), and Sempra Energy (3.6 million tpy).

Energy and Mineral Resources Minister Purnomo Yusgiantoro said he would like BP to sell LNG from the trains under consideration as several domestic firms, including state-owned Perusahaan Listrik Negara and Perusahaan Gas Negara, have shown interest in buying gas from Tangguh.

Fos Cavaou LNG terminal in France delayed

Societe du Terminal Methanier de Fos Cavaou (STMFC) has informed France's Energy Regulatory Commission (CRE) of a major delay in work being carried out to bring its Fos Cavaou LNG terminal in southeastern France on stream in April 2008. STMFC will operate the terminal on behalf of owners, Gaz de France 69.7% and Total SA 30.3% (OGJ, June 11, 2007, Newsletter).

CRE, in turn, announced it would postpone new tariff propositions for LNG terminal users, which originally had been scheduled for the end of October.

As matters now stand, CRE is unable to propose new tariffs because the current ones for the existing Fos Tonkin and Montoir-de-Bretagne terminals had been designed to apply only until Fos Cavaou came on stream.

Gaz de France told OGJ that, at this stage, it is unable to indicate when Fos Cavaou will become operational. ✦

Letters

Ethanol no palliative

The editorial, "Biofuels meet doubt," (O&GJ September 24, 2007) tells us that the Organization for Economic Cooperation and Development's Round Table on Sustainable Development views the rush to biofuels as environmentally and economically unsustainable (OGJ, Sept. 24, 2007, p. 17). This becomes increasingly clear as the domestic production of ethanol rises, and there is a corresponding increase in the price of corn-based products. The diversion of foodstuffs into automotive fuels is, in effect, a regressive tax and a simple misallocation of national agricultural resources.

Moreover, government should stop subsidizing the production of ethanol. Energy prices have increased to the point where the 51¢/gal subsidy, which may have appeared justified at one time, is no longer tenable. Subsidies should never be viewed as largess in perpetuity, and Congress should discontinue its unwarranted subsidy of ethanol production. Can you imagine the public furor that would arise if government were to extend the same $21.42/bbl subsidy to domestic oil producers? Would that the oil industry had the same clout in Washington that agricultural lobbyists have!

In August 2005, Congress passed legislation calling for ethanol production to be increased by 2012 to 7.5 billion gal/year, up from 4 billion gal/year at that time. With increasing gasoline prices and governmental incentives, it appears that this objective will be attained well before 2012. This level of ethanol production will cost taxpayers nearly $4 billion/year in subsidies, and the cost of corn-based food products will rise accordingly. It is generally agreed among those who have studied the issue that ethanol will not make economic or environmental sense until it is possible to produce it from cellulose and not corn.

Proponents of increasing ethanol production speak glowingly of moving toward energy independence. This is unrealistic when it is recognized that even at the 7.5-billion gal/year production level, ethanol will amount to less than 4% of current US petroleum imports. More to the point, this does not factor in the energy required to produce a gallon of ethanol, which is nearly equal to (if not more than) the energy that can be derived from that gallon of ethanol.

Increasing ethanol production is no palliative to the developing energy crisis; rather, it is a growing burden on the nation's economy. It would be far wiser to accelerate the application of higher corporate average fuel efficiency standards and increase vehicular mileage, thereby making a meaningful start in reducing our reliance on petroleum imports.

Thomas S. Wyman
Palo Alto, Calif.

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

NOVEMBER

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

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

Regional Mangystau Oil & Gas Exhibition & Conference, Aktau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-9.

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

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

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.

Turkemenistan International Oil & Gas Conference, Ashgabat, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 14-15.

Annual Unconventional Gas Conference, Calgary, Alta., (866) 851-3517, e-mail: conference@emc2events.com, website: www.csugconference.ca. 14-16.

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.

DryTree & Riser Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.drytreeforum.com. 28.

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.

DECEMBER

International Oil and Gas Industry Exhibition & Conference, Suntec, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 2-5.

Middle East Nondestructive Testing Conference & Exhibition, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 2-5.

International Petroleum Technology Conference, Dubai, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 4-6.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 5-6.

Oil & Gas Maintenance & Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

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

2008

JANUARY

Middle East Petrotech Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com/oil. 14-16.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), website: www.wfes08.com. 21-23.

API Exploration & Production Winter Standards Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 21-25.

API/AGA Oil & Gas Pipeline Welding Practices Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-25.

International Forum Process Analytical Technology (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 27-30.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 29-31.

Petroleum Exploration Society of Great Britain Geophysical Seminar, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: pesgb@pesgb.org.co.uk, website: www.pesgb.org.uk. 30-31.

SIHGAZ International Hydrocarbon and Gas Fair, Hassi Messaoud, Algeria, website: www.sihgaz2008.com. Jan. 30-Feb. 3.

Mixing oil, wikis, and blogs

Uchenna Izundu
International Editor

New media—like wikis, blogs, social networking, and tagging tools—raise interesting questions about how businesses should utilize them. Can new media improve communication, decision-making, and innovation within companies? How do they affect relationships between a business and its customers?

These issues are particularly pertinent for the petroleum industry, which is misunderstood as greedy and selfish. An unfavorable image has made it difficult to attract talented workers, especially in technical and engineering roles, and hold rational public debates about energy policy.

Nevertheless, oil companies are using new media tools for training employees and building relationships with the public.

BP PLC, for example, will become part of the online gaming community, SimCity Societies, in a new partnership with Electronic Arts. BP will offer a game in which players "build" power plants and can choose options such as wind, gas, and hydrogen instead of conventional energy sources, affecting emission levels within their virtual societies. The game encourages people to learn about causes and consequences of global warming in an educational and meaningful way.

Social networking

Chevron Corp. supports debate about a variety of energy topics on its social networking site, willyoujoinus.com, which was launched 18 months ago. It also sends bloggers information about the company and its issues.

A Chevron spokesman said: "Dealing with new media and, in the case of willyoujoinus.com, actually creating a new media vehicle, lets us engage with a much wider and nontraditional group of stakeholders. We think this is critical as part of our objective to create more 'energy literacy' among people who create and/or influence energy policy."

BP has also launched training for staff members via Second Life, the virtual community where individuals can create alternative lives depending on their level of membership. Presently it claims to have over 8 million registered residents. BP is using simulation environments to train tank-truck drivers in maneuvering around a forecourt. It also holds meetings in Second Life rooms that replicate BP's offices in the real world to foster creative problem-solving and link employees who would otherwise feel disconnected in a teleconference.

Despite these examples, Ralph Kappler, director and founder of Halo Energy, an energy and marketing communications firm, told OGJ that the energy industry is not doing enough to engage with a wider range of audiences. "Sometimes the industry gets proactive when in fact there is still very little to show (or proof for that matter), e.g. with so-called 'clean coal' or 'clean nuclear'."

The difficulty for energy companies is striking the right balance: They cannot be seen as Goliaths hijacking new technologies on networking sites, which have been personally designed for social interaction. Consequently, many networking forums are unlikely to welcome forays by the corporate world into their spheres.

Consistent message

A company must have a clear and consistent message before it uses these innovative tools. The scale of new media and targeting communications in a relevant way is a major challenge. Kappler cautions that "message and user reactions are based on instant, 'split-of-a second' decisions and feedback." Without a robust communications strategy, he adds, a company can find it risky to rush into new media to try solving communications problems it didn't address effectively in standard media like print, advertising, and TV.

Research by professional services firm KPMG shows that many companies are using new technologies. The main barriers are security concerns, confidentiality, and in some countries cultural and legal issues. Indeed, even organizational culture can hinder progress if senior managers struggle to understand how to reap the benefits of modern technologies. "Companies need to be alert to the dangers that free comment made in wikis and blogs may be libelous or infringe employee rights laws," said Crispin O'Brien, head of technology at KPMG.

Energy companies are cautiously monitoring how online media are evolving and how they can best use them to communicate with wider audiences. But their confidence needs to increase quickly as public debates intensify about climate change, high energy prices, and energy efficiency. Using new media to create and maintain existing relationships with various target groups requires many participants and regular postings. Investing in these demand commitment: The work of communicating has, ironically, become harder. ✦

Editorial

Energy bills in context

The worst US energy legislation in years should be viewed in context. The House and Senate have passed destructive energy bills while losing control of federal spending and threatening to raise taxes. Although the energy bills certainly slap the oil and gas business, the broader context makes clear that Congress has no intention of confining pain to a single, unpopular industry.

If enacted along with many of the spending and taxation measures under consideration, costly energy law would be just one blow in an official pummeling of the US economy. Individually, some proposals can seem affordable. Taken together, they promise a system of twisted incentives and punishing costs. And they emerge from a dreadful ascendance of goodie-bag politics abetted by a tax system needing reform.

Spending spree

According to the politically conservative Heritage Foundation, the 110th Congress has passed legislation in its first 10 months that would increase federal spending by $454 billion and taxes and fees by $98 billion over 10 years. Even larger tax hikes are in prospect. In an Oct. 30 report, Brian M. Riedl, a fellow of the foundation's Thomas A. Roe Institute for Economic Policy, says the congressional budget resolution would bring the projected tax increase to $2.7 trillion.

Lawmakers, of course, always try to camouflage their gropes for the money, which is partly why the oil and gas business finds itself under attack. House legislation would raise taxes on oil and gas production and spend proceeds on politically favored, uncompetitive energy forms. For consumers, replacing oil and gas with costlier alternatives is expensive. In fact, a governmentally induced jump in energy costs sounds more like a tax hike than the market-driven increases in oil and gas prices popularly fitted to the analogy.

Now lawmakers want to hike individual income tax rates. With energy, they coat mistakes with false virtues like energy independence. With taxes, they're disguising mischief with a semblance of reform.

Rep. Charles B. Rangel (D-NY), chairman of the House Ways and Means Committee, on Oct. 24 proposed a bill that he said would cut tax rates for 90 million working families but that Republicans on his committee called the largest individual income tax hike in history. The legislation would repeal the alternative minimum tax (AMT), which was designed to keep the wealthiest Americans from escaping income taxation but has come to threaten millions of middle-class taxpayers. Repeal is in order. But Rangel's measure would offset the revenue effects with, among other things, a 4% surcharge on upper-bracket taxpayers. Republicans say it would raise marginal tax rates—the key to economic effects—to 44% from 35%, well above the average of industrial countries.

Rep. Jim McCrery, the ranking Republican member of the committee, called Rangel's claim about tax cuts "hokum" because of changes beyond AMT repeal. And he said insisting that AMT relief be offset by tax increases elsewhere would "lock Congress into a system where we are guaranteed to raise taxes by $3.5 trillion over 10 years."

The threat of a huge, direct tax hike thus joins energy costs set to be lifted by government mistakes. The economy hasn't been in this much peril since before the presidency of Ronald Reagan.

What's needed

Neither energy nor tax policy should be this complicated—or this dangerous.

In tax policy, Congress should first repeal the AMT. That's all: Repeal an economic mouse that became a monster without compensating for supposedly lost revenue Congress never intended to collect. Then it should reform the tax code to lower marginal rates and eliminate complexity. Lower rates would help the economy. Simplification would deactivate a potent tool of political misbehavior. Energy goals should be even simpler: maximum domestic production of commercial energy in a market free of political influence.

On too many fronts, Congress is yielding to political impulses at the expense of real virtues like fiscal responsibility, honest taxation, and economic energy. Its actions threaten long-term prosperity. Both political parties deserve blame. The one that reverses course deserves to win control of Congress and the White House a year from now. ✦

Task force: US can shrink oil gap with unconventional fuels

Judy R. Clark
Senior Associate Editor

The US government and oil industry must jointly take aggressive action to slow the growth in oil demand and to increase oil supply with help from unconventional sources, reported the Federal Task Force on Strategic Unconventional Fuels in September.

The higher cost and volume of US crude and product imports, the task force charged, have exacerbated the nation's trade deficit, weakened the dollar against other currencies, and put national security and economic stability at risk.

At the same time, international competition for oil supply is intensifying, and "increasingly unstable sources pose strategic risks that the nation can ill afford to ignore," it said. Global oil demand is expected to increase to more than 110 million b/d by 2025 from 84 million b/d in 2005. US accounts for one fourth of that total (Table 1). During 1985-2004, US demand for oil increased by 25% to 20 million b/d, and imports more than doubled to over 12 million b/d. The Energy Information Administration (EIA) projects that US oil and products imports will increase to 18 million b/d (65% of demand) by 2030.

World oil demand

Table 1

	2005	2025
	Million b/d	
US	20.7 (25%)	26.1 (24%)
China	6.9 (8%)	13.2 (12%)
India	2.6 (3%)	4.1 (4%)
Rest of world	53.8 (64%)	67.3 (60%)
Total world	**84**	**110.7**

Sources: US Department of Energy, US Energy Information Administration, International Petroleum Monthly, November 2006, International Energy Outlook 2006

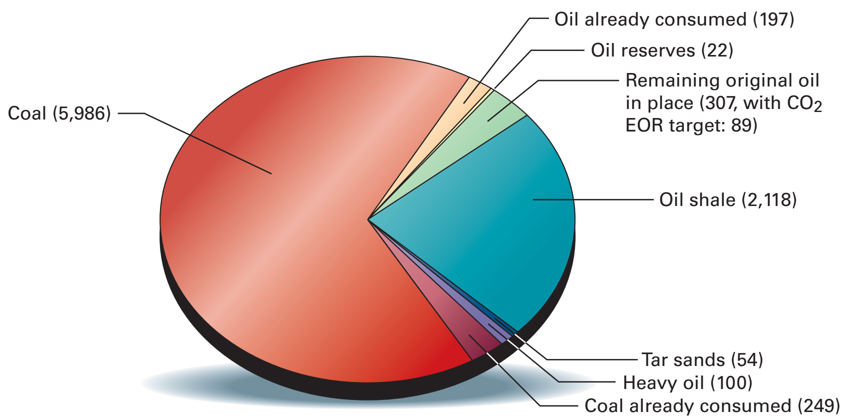
In response, the task force—established by the Secretary of Energy under Section 369 of the Energy Policy Act of 2005 (EPACT)—completed in February an integrated strategy to accelerate commercial development of unconventional fuels such as oil shale, tar sands, heavy oil, and liquids-from-coal and to implement methods of enhancing US oil recovery (OGJ Online, Aug. 20, 2007).

The task force evaluated the global and US oil supply outlook and assessed domestic unconventional fuels resources that could augment supply (Fig. 1).

It then described a plan for developing an unconventional-fuels industry that it said could supply all of the Department of Defense's domestic fuels demand by 2016 and add as much as 7 million boe/d of liquid fuels to US markets by 2035 (Fig. 2).

US solid and liquid fuels resources*

Fig. 1



*Resources are given in billion boe. Total=9.033 trillion boe. (Does not include energy losses in transformation to liquid fuel.)
Sources: US Department of Energy, US Energy Information Administration, National Energy Technology Laboratory, US Geological Survey, www.calforum.org/usa.

Aggressive implementation could displace imports worth $16-33 billion/year in 2015 and $32-133 billion/year in 2035 (Table 2).

According to the task force, reducing the annual cost of imported oil and products could increase the US gross domestic product (GDP) by $133 billion and contribute $29 billion to net annual direct public industry revenues from rents, royalties, and corporate and individual taxes. "Expected direct program outlays are estimated to be on the order of $3 billion," the task force said.

Incremental production goals for 2035 include 2.5 million b/d from oil shale, 530,000 b/d from tar sands, 2.6 million b/d from coal liquids, 750,000 b/d from heavy oil, and 1.3 million b/d from enhanced oil recovery via carbon dioxide injection.

Although the task force expects industry to develop most of the unconventional fuels, it identified options that federal, state, and local policy-makers can employ as incentives to encourage public investment and speed development (Table 3).

The task force also examined environmental considerations, markets, carbon management, and the socioeconomic ramifications of each plan.

Constraints on investment

Saying that development of an industry able to produce large amounts of unconventional fuel might require 20 years, the task force identified these constraints on investment:

• Access to resources on public lands, particularly for oil shale, tar sands, and coal resources.

• Economics, high capital and operating costs, unfavorable tax and fiscal regimes, oil price volatility, and long lead times before payback.

• Technology readiness, performance, and efficiency. Technologies that require further advancement or demonstration at commercially representative scale.

• Environmental requirements, permitting processes and timelines, water supply, air quality, and carbon management.

Uncertain regulation, other permitting processes, and timelines that impact planning and increase costs.

• Socioeconomic risks on affected states and communities that must be mitigated before development can begin.

• Oil price and market risks. Assured markets and long-term offtake commitments that provide a minimum rate of return to secure project financing.

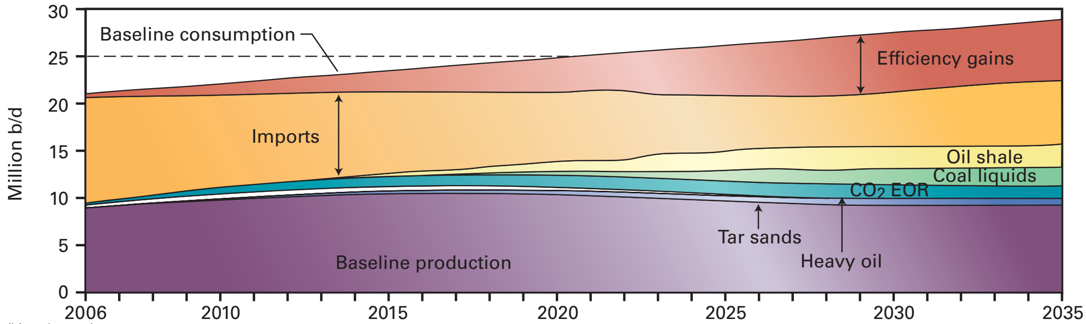
• Requirements and availability of basic support structures such as railroads and pipelines and water to support industry development, operations, and population and economic growth.

All of the constraints require public attention, the task force said (Table 4).

It recommended action, in many cases by government and industry working jointly, in resource access, technology, development

POTENTIAL US OIL PRODUCTION, CONSUMPTION*

Fig. 2



*Accelerated program case.
Source: US Department of Energy, NPOSR, NSURM Model, 2006

ANNUAL VALUE OF AVOIDED IMPORTS

Table 2

Case	2015	2025	2035
	Billion $/year		
Base	16.2	26.0	31.9
Measured	27.1	53.6	82.2
Accelerated	32.5	80.4	132.7

PROGRAM ELEMENTS PROPOSED

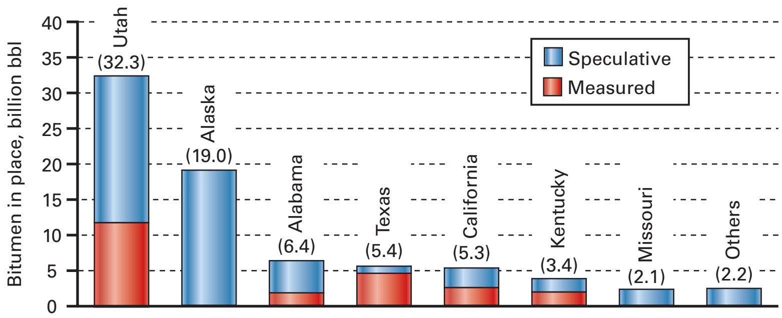
Table 3

Resource	Measured case	Accelerated case
Oil shale	Price guarantee, low $40s/bbl $5/bbl production tax credit[1]	Cost-shared demonstration projects
Tar sands	Price guarantee, low $40s/bbl $5/bbl production tax credit[1]	Cost-shared demonstration projects
Coal-to-liquids	Price guarantee, $41-61/bbl 20% investment tax credit[1]	Additional $5/bbl production tax credit[1]
Heavy oil	Extension of FY 1991 EOR tax credit[2]	R&D, wider application of state-of-the-art technologies
CO_2 EOR	Extension of FY 1991 EOR tax credit[2]	R&D, carbon capture and wider application Incentives to promote CO_2 capture and marketing from industrial sources

[1]All incentives limited to project payback. [2]Includes tax credit equal to 15% of full investment and injectant purchase costs.

US TAR SANDS RESOURCES

Fig. 3



Source: International Centre for Heavy Hydrocarbons, 1993 US bitumen database

economics, environmental protection, water-resource stewardship, socioeconomic effects, regulations and permitting, transportation, markets, government organization, and assessments of benefits and outlays.

Oil shale

The US has a shale oil resource estimated at 2 trillion bbl, primarily in Colorado, Utah, and Wyoming (see map, OGJ Aug. 9, 2004, p. 16). The task force targets production of 2.5 million b/d of shale oil by 2035, which requires a major commitment by the industry and the local, state, and federal governments.

Assuming a long-term oil price of $35/bbl, a $5/bbl production tax, and development of high-risk, cost-shared demonstration projects, the task force says production could begin in 2010 with about 40,000 b/d as the new technology is tested. Later improvements would boost production to 250,000 b/d by 2014, 2 million b/d by 2025, and 2.4 million b/d by 2030.

Technology used to develop shale oil is similar to that of Canada's oil sands: mining and ore preparation, extraction, coking and retorting, and upgrading, along with environmental mitigation.

All analyses are based on the National Strategic Unconventional Resource Model (NSURM) developed for the task force by the Department of Energy's Office of Petroleum Reserves.

Oil shale deposits also underlie much of the eastern US from Mississippi to New York, with near-surface mineable resources estimated at 423 billion bbl. Of that total, 98% is in Kentucky, Ohio, Tennessee, and Indiana. With processing technology advances such as the addition of hydrogen to retorting, potential oil yields could approach those of the western shale. Eastern shales are close to major demand centers, which would reduce transportation costs.

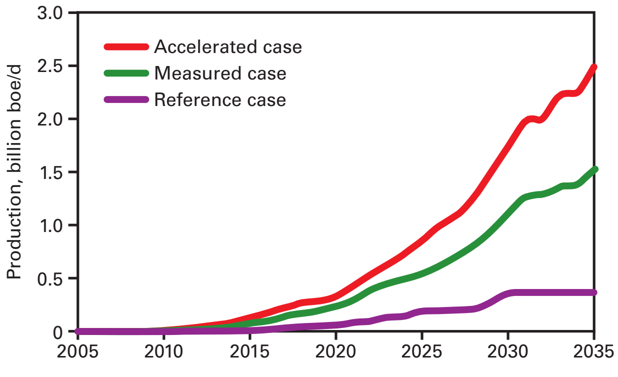
Nearly 80% of the western oil shale resource is on public lands managed by the Bureau of Land Management.

Other actions needed for oil shale development:

- Undertake a comprehensive study of the eastern oil shale potential.
- Assure access to oil shale resources on public lands sufficient to meet industry needs and national goals.
- Develop a leasing strategy to determine optimal lease block configurations, as lease holdings currently are too fragmented.
- Resolve conflicts with natural gas production and other surface uses that may conflict with oil shale development.
- Craft a fast-track technology program to attract capital investment.
- Support demonstration of efficient first-generation technologies while carrying out parallel efforts to develop and demonstrate the next generation technology.
- Prepare a plan to assure markets for initial production.
- Meet or exceed public standards and requirements for environmental protection.
- Provide an inclusive regulatory system and review process that allows expeditious development and a predictable schedule for permitting.
- Assess requirements for regional upgrading facilities to bring the oil to pipeline quality, and determine the need for additional pipelines and refining facilities as production increases.

US COAL-TO-LIQUIDS GOALS

Fig. 4



Tar sands

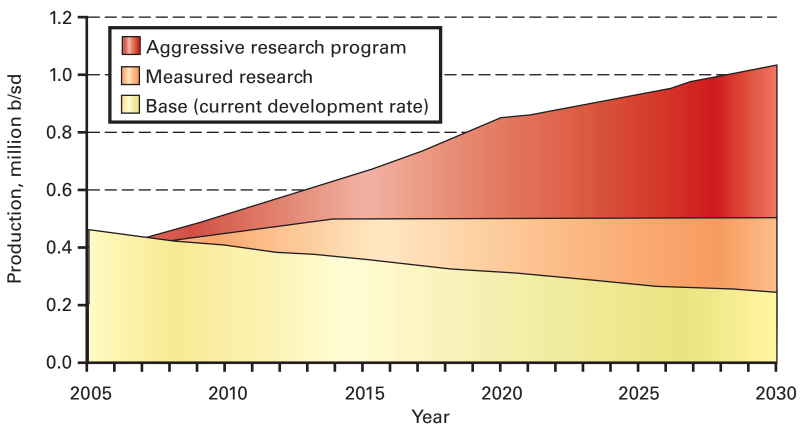
With the exception of about 2,700 b/d produced in situ from four California fields, oil is not currently produced from tar sands in commercial quantity in the US. However, interest in US tar sands is high, and the program goal is to produce 350,000 b/d by 2035.

The first planned milestones will be two or three small, economically viable ventures producing bitumen or asphalt followed by several larger integrated plants manufacturing synthetic crude.

Of the estimated 60-80 billion bbl of tar sands oil in the US, about 11 billion bbl may be recoverable. Utah has 19-32 billion bbl of measured tar sands, about one third of the domestic resource, with the balance in

US HEAVY OIL DEVELOPMENT SCHEDULE*

Fig. 5



*Includes Alaska resource, not explicitly modeled in National Strategic Unconventional Resource Model
Source: Heavy Oil Work Group, 2007

Alabama, Texas, California, Kentucky, and other states. Alaska is thought to have 19 billion bbl of tar sands resources (Fig 3).

New extraction technology approaches may be required for US tar sands, which differ in quality and grade from tar sands in Canada, where established methodologies have been in place for 35 years and where technology has greatly improved. Canadian production is about 1 million b/d, including both mining-based and thermal production (OGJ, Aug. 9, 2003, p. 16).

US tar sands are oil-wet and consolidated, with variable and unpredictable grades, and achieving production goals will require activity in technological, fiscal, and institutional areas, said the task force.

The viscosity of the bitumen, which distinguishes tar sands from extra heavy oil, may require some tar sands deposits to be mined.

A constraining factor, then, is the location of Utah tar sands on state and federally owned lands, some of which overlie oil and gas deposits and others that are in or adjacent to national or state parks, wilderness areas, or pristine environments where mining would be precluded or constrained.

Vapor extraction, which can be used with vertical or horizontal wells, is being explored but has not been field-tested. Cold production technology may apply where sand content is high. It requires much drilling but is more economic than thermal processes. To assure an adequate technology base, several technology approaches must be pursued, with use depending on the site.

University research is planned for basic and bench-scale studies. Two 66% federal cost-shared pilot plants are planned in the first year with two additional plants in the second year. In addition, 33% federal cost-shared semiworks and demonstration plants are envisioned.

Tar sands development is constrained as well by market risks, including the ability of existing refiners in target markets to absorb additional quantities of synthetic crude.

Coal-to-liquids

Coal is the most abundant fossil fuel in the US, with recoverable reserves estimated at 267 short tons, broadly distributed (see map). Based on current production of nearly 1.1 billion short tons/year, the US has a 250-year supply. That likely will increase as coal mining technology improves and additional geological data become available.

EIA's 2006 Annual Energy Outlook for the first time projects a developing market for coal liquids. By 2030, it said, coal liquids will provide 760,000 b/d (reference price case) or 1.69 million b/d (accelerated case; Fig. 4).

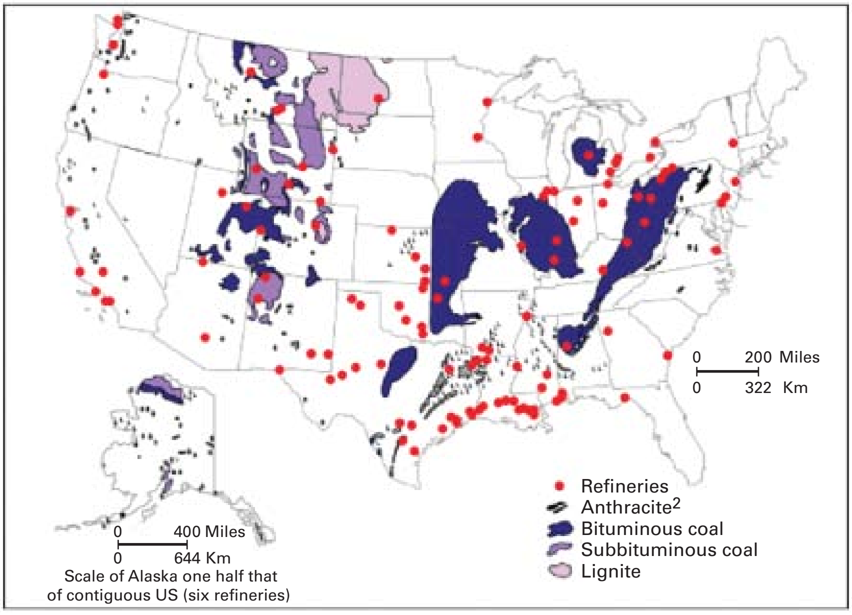
The goal is for federal, state, and local governments—cooperating with NGOs in a "Manhattan project" type crash program—to stimulate and assist

POSSIBLE LIMITATIONS TO UNCONVENTIONAL FUELS DEVELOPMENT

Table 4

	Site Access	Utilities	Product Movement	Community Infrastructure
Shale oil	Roads and railroads	Substantial use of electricity, natural gas for in situ operations. Water availability as the industry grows.	Major new crude pipeline to connect with existing pipeline system.	Substantial need for temporary-permanent housing. Substantial increase in demand for community services.
Tar sands	Roads and railroads	—	New pipelines may have synergies with shale oil pipelines.	Temporary-permanent housing. Increased demand for community services.
Coal liquids	Roads, railroads, and barge capacity	Water availability could be a factor depending on location.	Major truck, rail or barge expansion capacity.	Temporary housing needed for construction workers.
Heavy oil	Alaska could have special location considerations.	Expanded natural gas used for steam generation.	—	—
CO_2 EOR	New pipelines to deliver CO_2 from source to field.	—	—	—

US COAL DEPOSITS AND PROXIMITY OF REFINERIES



Sources: DOE, EIA "US Coal Reserves," 2004

private industry development of a coal-to-liquids (CTL) industry. The governments would set an oil floor price to minimize the risk of a prolonged oil price collapse; provide economic incentives such as tax credits, and loan and purchase guarantees to accelerate development; and participate in early design feasibility studies, engineering design, and permitting for first-of-kind projects.

Large quantities of coal would have to be mined and transported. Congress would be urged to fund the needed transportation system expansion.

Coal can be converted into liquid fuels via direct liquefaction or by indirect liquefaction after gasification. Already, 14 proposals for commercial CTL projects have been announced in the US, although none has been built.

Although Sasol Ltd. has four pilot plants in South Africa that have successfully been using coal liquefaction technology since the 1950s, no commercial plant has been built that combines and integrates advanced coal gasification with advanced Fischer-Tropsch synthesis technologies. A 50,000 b/d plant is estimated to cost $3.5-4.5 billion to build. A strategic CTL industry might produce 2.6 million b/d of liquid fuels from coal by 2035.

A National Coal Council survey has shown that the mining industry and US transportation facilities can be expanded to accommodate growth in coal production by more than 2.3 billion tons/year by 2025. However, the US lacks facilities to build CTL plant components.

Heavy oil

The goal for a heavy oil research and development program is to stimulate private industry development of heavy oil resources—much of it in California, Alaska, and Wyoming—to increase domestic production to as much as 1 million b/d by 2025 (Fig. 5). The cumulative contribution to GDP would total $108 billion through 2030.

Considerable expansion of production technologies will be required. Use of steam injection, in situ combustion, cyclic steam injection, and more-advanced technologies involving horizontal wells, nonthermal recovery technologies, immiscible CO_2, and advanced thermal EOR could increase recovery of heavy oil, the task force said, particularly from Alaska's North Slope, which holds 25-40 billion bbl.

Given declining conventional North Slope oil production, heavy oil production would have to be accompanied by upgrading or the addition of diluent to allow the oil to be transported through the Trans-Alaska Pipeline System.

Program activities would include "basin-specific" public-private partnerships in key heavy oil basins and initiation of a collaborative effort with Canada, such as technology-sharing and jointly funded field research and development.

Enhanced oil recovery

Producing "stranded oil" from maturing fields with CO_2 for EOR could add more than 2 million b/d of production by 2035, according to task force projections. It would be accomplished with a basin-oriented approach toward 10 basin studies conducted by the DOE Office of Oil and Natural Gas.

A major element would be to expand the supply of CO_2, mostly from industrial sources, in a two-pronged benefit that would also reduce the amount of CO_2 released to the atmosphere. An improved, cost-effective technology would be developed to capture and supply "EOR-ready" CO_2.

Demand reduction

No single fuel source, however, is likely to substantially reduce the country's dependence on imported oil, the task force said. Despite adding the incremental supply from unconventional fuels development, the volume of net imports in 2035 would be only slightly reduced because of increases in demand (Fig. 2). Consequently, reducing demand must also be part of a strategy for lowering US oil imports.

The most likely place for efficiency gains relative to liquid fuels is in individual transportation. Increased vehicle mileage and reduced driving, the task force said, could lower net miles driven by 20% in 30 years in a moderate case and 30% in an accelerated case.

The full report is at www.unconventionalfuels.org. ✦

Gas industry, Senate members voice energy bill concerns

Nick Snow
Washington Editor

The American Petroleum Institute, Independent Petroleum Association of America, and seven other trade associations representing natural gas producers, pipelines and consumers jointly expressed strong concern Oct. 19 about US House energy legislation that they believe would reduce instead of increase domestic gas supplies.

In a letter to House Speaker Nancy Pelosi (D-Calif.) and US Senate Majority Leader Harry M. Reid (D-Nev.), the organizations said that HR 3221 "professes to focus on energy independence, yet if enacted would adversely affect natural gas production and infrastructure development, thereby making the supply of this important energy resource even less secure"

The Natural Gas Supply Association, Interstate Natural Gas Association of America, National Ocean Industries Association, American Exploration and Production Council, Industrial Energy Consumers of America, Process Gas Consumers Group, and US Oil and Gas Association also signed the letter.

It came as the ranking minority members of three Senate committees urged Reid and Minority Leader Mitch McConnell (R-Ken.) to convene a formal House-Senate conference to reconcile differences between HR 6, which the Senate passed June 21, and HR 3221, which the House approved Aug. 4 (OGJ, Aug. 20, 2007, p. 84).

Bypassing conference

"Last Wednesday, Speaker Pelosi announced her intention to bypass the appointment of a conference committee to reconcile the differences between these two bills," said Pete V. Domenici (R-NM) of the Energy and Natural Resources Committee, James M. Inhofe (R-Okla.) of the Environment and Public Works Committee, and Ted Stevens (R-Alas.) of the Science and Transportation Committee.

"We regret the speaker's decision to do this and we are deeply concerned about the integrity of long-standing procedures in the Congress if the speaker's decision is allowed to stand," they added in a letter to the Senate's leaders.

A House source told OGJ that Pelosi on Oct. 11 instructed House committee chairmen who have jurisdiction in energy matters to initiate less formal talks with their Senate counterparts after becoming frustrated with what House Democrats considered delays by Senate Republicans in convening a conference.

Pelosi said in an Oct. 12 press conference that the bill, HR 6, which the Senate passed, dealt only with "repealing subsidies to 'Big Oil' and creating a renewable energy fund" and that HR 3221 includes provisions to increase energy security and reverse global warming. "There is nothing I would like better than to have a conference, to have a full and open discussion of the issues that are in the House and Senate bills and come to resolution in a bipartisan, bicameral way," she maintained.

She also said she hoped the resulting bill would be legislation that President George W. Bush could sign. Alan B. Hubbard, assistant to the president for economic policy and director of the National Economic Council, told her in an Oct. 15 letter that Bush would veto any energy bill that reduced instead of increased domestic production, raised taxes or used the tax code to single out specific industries, or imposed price controls.

That led Rep. Edward J. Markey (D-Mass.), who chairs the House Select Committee on Energy Independence and Global Warming, to observe on Oct. 16: "The Bush administration just doesn't get it. Ever since the Cheney energy plan set America on a foolish course to try to drill our way to energy independence, we have been learning the hard way that no matter much money you heap on the oil industry, and no matter how much the oil cartel drives up prices, and no matter how many new oil wells get drilled, we are no closer to energy independence than when this administration took over."

Most immediate, reliable

In their letter to Pelosi and Reid, the nine trade associations called natural gas "the most immediate, most reliable option available to reduce power plant emissions as we await the development and deployment of other clean energy technologies." The 2005 Energy Policy Act contains several provisions to encourage production in frontier areas, including ultradeep water, ultradeep gas, and offshore Alaska, which HR 3221 seeks to repeal, they said.

They listed 20 provisions of Title VII and three provisions of Title XIII that they said would adversely affect domestic gas development. The provisions concern taxes, deepwater royalty relief and price thresholds, water management, federal audits, drilling permit application processing, and other issues.

"We are puzzled that so far this Congress has focused so little on natural gas," the letter said. "Despite the numerous hearings on climate change and on energy policy this year, not a single natural gas industry witness has been invited to testify at a hearing, House or Senate, on future natural gas demand and supply dynamics in a carbon-constrained environment. Given that natural gas accounts for 25% of US energy consumption, this is a stunning oversight."

Specifically, it said, Congress has not examined the impact of increased ethanol production on gas demand. "Even more significantly, recent modeling of the McCain-Lieberman climate change legislation, S 280, sponsored by the Natural Gas Council, suggests that a

20% increase in natural gas demand by 2030 is quite possible given the need to meet the emissions reduction targets that would be mandated by that legislation," it continued.

The letter urged the House and Senate "to consider carefully how these and other policies will affect natural gas demand so that the nation can develop adequate supplies and infrastructure now and thus avoid future adverse consequences." ✦

US Supreme Court to hear Exxon Valdez appeal

Nick Snow
Washington Editor

The US Supreme Court agreed Oct. 29 to hear an appeal of the $2.5 billion punitive damages award stemming from the 1989 grounding of the tanker Exxon Valdez and subsequent crude oil spill in Alaska's Prince William Sound.

The court did not set a date for arguments in the case, Exxon Shipping Co. vs. Baker, but appears likely to hear the case next spring.

The spill of more than 261,900 bbl of crude into the sound led to a jury's record $5 billion punitive damages award, which the federal ninth circuit appeals court cut in half. ExxonMobil Corp. appealed that decision to the Supreme Court on Aug. 20.

An Oct. 29 update on the website of the Faegre & Benson law firm, which represents more than 30,000 plaintiffs in the case, said that the high court's review will be limited to maritime law issues. The court declined a claim the verdict was excessive under the US Constitution's due process clause, and refused to hear a cross-appeal seeking to reinstate the $5 billion damages award, the law firm said.

ExxonMobil welcomed the Supreme Court's announcement. "This case has never been about compensating people for actual damages. Rather it is about whether further punishment is warranted in a case where a company voluntarily compensated most plaintiffs within a year of the spill, and has spent over $3.5 billion, including compensatory payments, cleanup payments, settlements and fines. We do not believe any punitive damages are warranted in this case," it said in a statement on Oct. 29.

Alaska Gov. Sarah Palin called the high court's decision to hear the appeal "a kick in Alaskans' collective gut." The fishing industry and coastal communities of Prince William Sound still have not recovered, she continued in a statement issued in Juneau on Oct. 29. "It seems to be a case of justice delayed is justice denied. I believe this has gone on too long," Palin said.

ExxonMobil said a large number of trade associations filed briefs in support of its appeal, an indication of the business community's concern about the case. The maritime industry also is watching it closely, the company said.

"It is important that the Supreme Court hear this case to provide guidance to the lower courts on the application of punitive damages. It is also important for the Supreme Court to uphold long-standing maritime law that provides that ship-owners are not liable for punitive damages based upon conduct by the ship-master who disregarded the owner's rules and policies," ExxonMobil said. ✦

BP unit agrees to record settlement with CFTC

Nick Snow
Washington Editor

BP Products North America Inc. has agreed to pay $303 million in fines to settle charges that it manipulated propane markets in February 2004 and April 2003, the US Commodity Futures Trading Commission announced.

It is the largest manipulation settlement in the agency's history, according to Walt Lukken, CFTC's acting chairman. "BP engaged in a massive manipulation. The magnitude of this settlement reflects that the commission will not tolerate trading abuses in our open and competitive markets," he said on Oct. 25.

The settlement represents most of the more than $370 million that BP agreed to pay to settle a series of federal charges, the US Department of Justice said in a separate announcement. Other US subsidiaries of the multinational company will pay a record $50 million in criminal fines to settle Clean Air Act charges stemming from the Mar. 23, 2005, fire and explosion at its Texas City, Tex., refinery, and $20 million in criminal fines and restitution for violation of the Clean Water Act relating to oil pipeline leaks in Alaska.

"These agreements are an admission that, in these instances, our operations failed to meet our own standards and the requirements of the law. For that, we apologize," said Robert A. Malone, BP America chairman and president.

"They represent an absolute commitment to work with the government as we continue our efforts to prevent another tragedy like Texas City, to make our Prudhoe Bay pipeline corrosion program more responsive to changing operating conditions, and to ensure that

Oil's changing relationships

Memo to US, Canadian, and other Western nations' oil and gas producers: Russia and Caspian Basin nations are renegotiating agreements with stricter terms. Production-sharing agreements with incentives to attract outside investment in exchange for assuming certain initial risks are rapidly becoming history. But the deals are still better than in the Middle East.

"Russia is phasing out PSAs, and in Kazakhstan a PSA for Kashagan, one of its biggest fields, has been reopened for negotiation," said Ariel Cohen, an energy security analyst, last month at the Center for Strategic and International Studies. "Some Western companies may not like what is happening. But with oil prices close to $90/bbl, we cannot afford to ignore any major producing basin."

With about 80% of the world's remaining reserves held by government-owned companies, the relationship between resource-rich nations and outside exploration and development partners has changed.

Clearer agreements

Future agreements will have to be clearer than they have been, said Cohen, a senior research fellow at the Heritage Foundation.

"Parties will have to be more specific about costs and recovery mechanisms, about tax regimes, and about relationships between government leaders and energy projects. Leaders now are becoming involved at the highest level," he said.

Kazakhstan, he said, apparently grew unhappy with Eni's performance as Kashagan operator as cost estimates rose two-and-a-half times and initial production was delayed until 2010. The government is seeking a bigger share and, possibly, a new operator.

Russia has taken a harder line with its outside partners because it apparently believes it has enough resources and financing, Cohen said. Central Asian governments are likelier to seek technology agreements, "but it's a shifting landscape."

He said he hopes those countries' leaders "don't put all their geopolitical eggs in one basket," although it appears inevitable they'll be pressured by their larger neighbors to do just that.

Multinational oil companies and large service and supply firms still have marketing, financial, and technical advantages. But Cohen warned that without coordinated national policies they'll continue "to try to beat each other to the next barrel.

'Don't over-promise'

"To these companies, I say: Please don't over-promise. If a project will take 7 years to develop, please don't say it will take 5 and hope you can talk your way out of it. This will simply hasten tighter control by government-owned companies of the world's remaining resources," he said.

Western companies also should recognize that government representatives might be more than they appear, Cohen said. "The Russian sitting across the table might be a venture capitalist, internal security agent, and crime syndicate member simultaneously. The Russians apparently are comfortable with this," he said.

"Companies need to recognize that their employees have to understand government relations. There have been instances where blue-chip companies placed production engineers in charge and wound up with egg on their faces." ✦

our participation in the nation's energy markets is already appropriate," Malone said Oct. 25 in Houston.

Order's components

The Oct. 25 consent order with the CFTC requires BP to pay a $125 million civil penalty, establish a compliance program, and install a monitor to oversee its commodities trading activities. It also requires BP to pay $53 million into a restitution fund for victims, CFTC said.

Simultaneously, DOJ's criminal division fraud section filed a deferred prosecution agreement under which BP will pay a $125 million criminal fine and $25 million into a consumer fraud fund, CFTC said.

It explained that the TET propane market refers to propane deliverable at the Teppco storage facility at Mont Belvieu, Tex., or anywhere within the Teppco pipeline that runs from Mont Belvieu into Ohio, Illinois, and Pennsylvania. The system is the only one that transports propane from Mont Belvieu to the US Northeast.

CFTC investigators found that BP employees used the company's financial resources to buy more than the available TET propane supply in February 2004. By the end of the month, they controlled enough of the supply to dictate prices to other market participants and obtain a significant trading profit. They also found that BP employees attempted to corner the TET propane market in April 2003 by engaging in similar conduct.

"Although this case was difficult, our professional staff used strategic techniques during thousands of hours of investigation to uncover BP's misconduct. They effectively rooted out evidence of the defendant's intentions. This settlement shows that BP has decided to take positive steps to rectify the situation and provide relief to those citizens who were impacted by BP's misdeeds," said CFTC enforcement director Gregory Mocek.

In addition, a federal grand jury in Chicago returned a 20-count indict-

ment charging four former BP Products employees with conspiring to corner and manipulate the TET propane market in February 2004, and to sell TET propane at an artificially inflated index price in violation of federal mail and wire fraud statutes, along with substantive Commodity Exchange Act (CEA) violations and wire fraud, DOJ said.

The federal grand jury charged Mark David Radley, James Warren Summers, Cody Dean Claborn, and Carrie Kienenberger with violating the CEA and federal mail and wire fraud statutes. Another former BP Products trader, Dennis N. Abbott, pleaded guilty on June 28 to one count of conspiracy to manipulate and corner the propane market.

"Our view of the legality of these trades changed as our knowledge of the facts surrounding them became more complete," said Malone. "This settlement acknowledges our failure to adequately oversee our trading operation. The agreement provides compensation for victims and establishes a foundation for working with the government to ensure our participation in the nation's energy markets is always appropriate. We are determined to restore the trust of regulators in our trading operations."

Bhopal provision

The $50 million fine stemming from the Texas City refinery explosion and fire also was the first prosecution under a CAA requirement for refineries and chemical plants to take steps to prevent accidental releases which Congress passed in 1990 following the explosion at Union Carbide's chemical plant in Bhopal, India, according to the US Environmental Protection Agency.

BP Products North America also agreed to plead guilty to a felony violation of the CAA and will serve 3 years' probation for failing to have adequate written procedures for maintaining the mechanical integrity of process equipment at the refinery and for failing to inform contractors of the hazards related to their occupying temporary trailers near the plant's isomerization unit. It also will complete a facility-wide study of its safety valves and renovated its flare system at the refinery to prevent excess emissions at an estimated cost of $265 million, EPA said.

"If our approach to process safety and risk management had been more disciplined and comprehensive, this tragedy could have been prevented," said Malone. "We did not provide our people with systems and processes that would have enabled them to appreciate the risk of a catastrophic release from the F20 blowdown stack and understand the danger of placing occupied trailers so close to it. We deeply regret the loss of life, the injuries, and the community disruption caused by the explosion."

A former EPA official applauded the penalties. "Let's hope these criminal fines wake up BP's management and force the company to clean up its refineries. BP spends a lot of money advertising itself as a 'green' corporation. Some of that money would be better spent protecting BP's workers and neighbors from the company's own pollution," said Eric Schaeffer, director of the Environmental Integrity Project.

Schaeffer also said that EPA and DOJ "deserve the public's thanks for this outstanding result."

For the Alaska oil spills from its North Slope gathering systems in March and August 2006, British Petroleum (Alaska) Inc. pleaded guilty to one misdemeanor of the CWA, EPA said. The BP America subsidiary will serve 3 years probation, pay $4 million to the National Fish and Wildlife Foundation to support North Slope research and activities, and pay $4 million in restitution to the state of Alaska. It also will be required to replace 16 miles of pipeline at an estimated cost of $150 million.

"This leak, and the spill that resulted from it, revealed a significant gap in our corrosion management program, a gap that existed because our approach to assessing and managing corrosion risk in these lines was not robust or systematic enough," Malone said. The company will work with state and federal regulators to assure that the Prudhoe Bay gathering system operate safely and reliably, he said. ✦

Alberta raises royalty rates but rejects oil sands tax

Alberta will raise royalty rates on production of oil, gas, and oil sands—but not by as much as a provincial advisory panel recently recommended.

A key departure from the controversial recommendations in what Premier Ed Stelmach labeled "the New Royalty Framework" is elimination of an oil sands severance tax (OSTT).

According to the government, the new framework will increase royalty receipts by $1.4 billion in 2010, 20% above the level projected for current regime but $500 million less than the increase estimated for the recommendations of the Royalty Review Panel (OGJ, Oct. 1, 2007, p. 25).

Those recommendations triggered a flurry of objections from oil and gas producers, who warned they would suppress already slumping gas drilling and discourage oil sands investment (OGJ, Oct. 8, 2007, p. 32).

The framework

The new royalty framework takes effect at the start of 2009.

In place of the OSST, it will raise the royalty rate on oil sands production both before and after operators recover initial costs (payout).

At present, the prepayout oil sands royalty is 1%. The new rate will be 1% until the crude price reaches $55/bbl and increase in steps to a maximum of 9% when the oil price is $120/bbl or more.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Eric Watkins, Senior Correspondent

Rebels target Sudan's oil

If you were counting on increased supplies of Sudanese crude to reduce the worldwide price of oil, you may need to think once again, especially given plans made by rebels in the country.

To be sure, the Sudanese government has dismissed threats to attack oil fields made by rebels of the Justice and Equality Movement, who claim one assault already, kidnapping two oil workers in the process.

"The JEM say that they will attack oil fields but these are dreams that will not come true," said Sudan's Defense Minister Abdel Rahman Mohammed Hussein, who did not confirm or deny rebel claims.

JEM field commander Abdulaziz al-Nur Ashr Oct. 23 said his forces had kidnapped two workers in an attack on the Defra oil field, run by the Greater Nile Petroleum Operating Co.

Talks boycotted

Talks on the Sudanese conflict were scheduled to start in Libya on Oct. 27, but JEM and the other main rebel group, SLA-Unity, boycotted them.

United Nations Sec. Gen. Ban Ki-moon announced the talks in September, hoping to achieve a political settlement before the planned deployment to Darfur of a 26,000-strong joint peacekeeping force of the African Union and the UN.

Sudanese President Omar Hassan Ahmed Al-Bashir said his government would initiate a ceasefire at the start of the Tripoli talks, but that he expected the rebel and opposition groups attending the talks to do the same.

Not surprisingly, the two main rebel groups—JEM and SLA-Unity—declined to attend the talks, saying the occasion would be a sham due to ringers introduced by the government.

"The mediation has fallen in the trap prepared by the government by making the negotiations an arena for every Jack, Tom, and Harry," said Mohammed Bahr Hamdeen, a senior JEM leader.

Even a day ahead of the planned meeting, peace mediators insisted they would press on with the negotiations despite the decision by the two rebel groups to boycott the talks, saying time was running out for the war-torn region.

Trump card

The absence of the rebels did not seem to bother the mediators very much, certainly not enough to recognize the invalidity of the proceedings.

"Anytime a significant movement figure is not present," said Salim Ahmed Salim, the African Unity representative who is helping mediate the talks, "it's not a plus for the negotiations." Not a plus? Goodness, it would seem to render them impossible.

One meditator, Jan Eliasson, the UN's special envoy to Darfur, even criticized the rebel groups for not working to settle the conflict. "I don't see this as a failure for the negotiations, but as a failure for those who have not seized the opportunity to move toward peace," said Eliasson.

But the rebels held the trump card: "Whatever happens in Sirte without JEM and SLA-Nur does not represent Darfur's people," said JEM's Abdulaziz.

More to the point, though, where will that leave Sudan's oil? ✦

The postpayout royalty, now 25%, will begin at that level and increase as the oil price rises above \$55/bbl to a maximum of 40% at \$120/bbl.

The government is in discussing participation in the new system with Syncrude and Suncor, whose oil sands mining projects are subject to royalty agreements expiring in 2016.

By June 30, 2008, it plans to have adopted a permanent, generic method for setting bitumen values for projects with low third-party sales.

The government rejected a recommended 5% upgrader credit envisioned as an inducement to build bitumen upgraders in Alberta, saying it would consider "other options."

For conventional oil and gas, the government will replace multitier systems with unified, elevated rates that vary with price and production rates, eliminating most special programs and vintages.

Oil royalty rates will rise to a maximum of 50% at an oil price of \$120/bbl. The current oil maximum rates are 30% for the old tier and 35% for the new tier under lower price thresholds.

The maximum gas royalty will rise to 50% from the current 35%, and tiers will be eliminated.

The government retained and will revamp its deep-gas drilling program and will apply lower royalty rates over a wide price ranges for wells with limited productivity.

It also retained a program that eliminates royalty on gas that would be flared without the incentive.

Balanced response

One early response to the framework was balanced.

"Overall, the impact of the government's proposals will have a significantly less serious impact on oil sands economics than the panel's recommendations, although the industry is likely to remain concerned about the increase in prepayback take that the increase in base royalty implies," said Derek Butter, head of corporate analysis for Wood

Mackenzie Ltd., Edinburgh.

The consultancy estimates the new system will reduce the net present value of current and planned oil sands projects by $10 billion (US) at a long-term, inflation-adjusted Brent crude price of $50/bbl. It estimated the value decline under the Royalty Review Panel's recommendations at $26 billion.

"From the point of view of new project development economics, the new royalty framework clearly recognizes the high break-even costs that the industry faces in the current operating environment," Butter said.

"We believe that there is a much reduced chance of the cancellation of proposed oil sands projects under the new framework than under the panel's proposals." ✦

Gas Summit: Changes could imperil gas supply, demand

Doris Leblond
OGJ Correspondent

The accelerating pace of change that has turned the gas market from relatively simple to increasingly complex and risky, has brought a new dimension to supply and demand security, said participants at the 12th International Gas Summit in Paris Oct. 17-18. The conference was sponsored by Institut Francais du Petrole, publisher-consultant Petrostrategie, and SPTEC Conseil.

Nordine Ait-Laoussine, president of Geneva-based consultant Nalcosa, set the tone in his introductory address. He blamed the European Commission for putting both demand and supply security at risk through proposed measures to restrict foreign ownership of downstream assets in the European Union and to extend the unbundling of production and transport to all investors, European and non-European alike.

If adopted, Laoussine warned, these measures "would raise the twin issues of supply security for the consumers and demand security for the producers." The Commission's proposed measures, he said, could "provide an added justification for exporting countries to pursue more vigorously the creation of the so-called 'Gas OPEC,'" as producers "want to access the downstream gas sector to achieve demand security."

Gaz de France Chairman and CEO Jean-François Cirelli also noted that applying the Commission's unbundling of production and transport-marketing to companies investing in the proposed Nabucco pipeline to Europe from the Caspian Sea area, for example, would cause those companies to have second thoughts about investing, and a derogation [partial repeal of the unbundling measure] would be required for it to go ahead. "Derogation means that there is a problem: If there is no derogation, there will be no investment," he said.

In the circumstances, the proposed EU measures could only increase already grave concerns about gas supply and demand.

Camillo Gloria, senior vice-president of Eni SPA's gas and power division, echoed other speakers' concern, saying gas purchasers and sellers are "caught in the middle of various forces that are currently reshaping the market." Supply security, he pointed out, is a constant challenge in an EU market permanently perceived as short: 200 billion cu m of gas will be needed to fill the supply-demand gap by 2020 at a cost of $800 billion in supply contracts.

Contingent issues on the demand side, such as the growing convergence of gas and electric power, also will likely impact gas supply security, Gloria said. Such a convergence is leading to the international electricity trade's affecting local [national] gas demand. In addition, mergers and acquisitions in the electric power industry are limiting or altering demand-side diversity, he said.

He added that these market changes are also bringing uncertainties to gas suppliers as "new, nontraditional" supply schemes flourish and negatively impact revenues from long-term gas sales, "which are often a relevant slice of suppliers' [gross domestic product]." These market changes also alter the traditional risk allocation between long-term buyers and sellers.

These views were shared by most speakers at the summit, including Sonatrach Executive Vice-Pres. Chawki Mohammed Rahal, who spoke of "an increasingly risky environment" that is "changing the nature, the goals, and the strategies of the operators."

The fast developing LNG trade has shifted the security of supply and demand balance across regional gas markets, noted many speakers. Jochen Weise, a board member of E.On Ruhrgas AG's gas supply and trading division, saw pipeline gas and LNG increasingly competing to 2020 as an additional source of supply for the EU. But in the long run, he warned, LNG will have to be cost-efficient and profitable compared with pipeline supplies, with oil-indexed long-term contracts and short-term gas trading continuing to inter react.

IFP's Jean-Pierre Favennec said LNG international trade volumes are projected to more than double by 2015—with a growing share from Middle East and Atlantic exporters—and they would be enough to supply a 2.5%/year demand growth. However, Patrick-G. Walliez, gas adviser to the CEO of Suez-Tractebel, cautioned that recent LNG supply projections continue to slide. Supply will be tight if some projects are postponed in Nigeria, Australia, and Iran, he ventured.

Total SA's Middle-East Pres. Ladislas Paskiewicz cautioned about Middle East gas supplies. Qatar and Iran aside, he said, "Little production (in the Middle East) remains in excess of local demand," and gas imbalances in some countries will result in new production

being redirected towards local markets.

High gas prices that render alternate fuels for electricity competitive could lead to gas demand destruction, impacting demand security, pointed out a number of speakers. Rahal said Sonatrach's approach to such uncertainties involve maintaining flexibility and portfolio diversification, capacity investment in LNG regasification terminals and export pipelines, and the holding of downstream positions through dedicated affiliates—a strategy that broadly echoes what both gas consumers and suppliers were advocating to counter fluctuating capacity risks.

Adding to the concerns expressed at the conference, Stuart Bradford, Shell's general manager of LNG commercial advice, introduced what he called "the wider challenge for LNG trade"—shipping. A rash of decisions about the number, type, and size of ships required as well as decisions about port and terminal locations underlie the strategic question: "Should my country develop an LNG shipping industry?" ✦

IFP: Oil equipment, services demand growth slows

Doris Leblond
OGJ Correspondent

Globally, oil field equipment and services have been in tight supply since 2005, but the demand growth rate is beginning to slow and may plateau in 2008, said officials at the Institut Francais du Petrole (IFP).

Investment growth in exploration and production jumped by 25% to $214 billion in 2005 and by 29% to $275 billion in 2006. However, this growth rate slowed to 13% in 2007, reaching $312 billion, because of soaring costs of both equipment and services.

In 2008, investment growth should plateau at 10-15%, reaching $340-$350 billion, IFP reported. The slowdown is masked by higher costs and is primarily due to postponement of a number of projects pushed back on average 6-7 months because of high costs.

"These costs account for 80% of the expenditure growth rate, leaving only 20% for volume growth," explained Nathalie Alazard, IFP's head of economic studies.

IFP noted investments in drilling onshore in North America, mainly in Canada, and in US shallow waters are on the wane. But the slack should be taken up 22% by China and 24% by Russia, officials said.

Geophysics companies posted a 19% growth rate in the first half of this year, pulled along by onshore seismic projects. The offshore sector is slowed by lack of equipment, as the seismic marine fleet is slow in renewing its units, and their availability remain tight.

Construction of new vessels will start this year and extend into 2008. Turnover this year is expected to hover around $11 billion, rising to $13 billion next year.

Drilling growth rates

The number of wells drilled rose 9% to 103,000 in 2006 and should reach 105,000 this year, only a 2% growth due to stagnating North American activity, which is up 12% in the US but down 27% in Canada. Drilling activity is growing worldwide, where 96% of the wells drilled are onshore.

The Middle East, especially Saudi Arabia, with its target of producing 12.5 million b/d by 2009, posted the highest drilling growth at 13%. In Africa the rate was 10%, pulled along by Egypt and Libya.

Compared with last year's offshore drilling growth rate of 7%, this year's offshore drilling growth should slow to 3%, with the steepest drop in the US as mature shallow fields are abandoned for deep offshore prospects.

Offshore drilling is highest in Latin America, especially Brazil and Mexico, up 15%. Asia accounts for a third of the wells drilled, some 1,500, and it has posted regular growth of 7-8%/year since 2005, mainly pulled along by Australia, India, and Malaysia.

The utilization rate of drilling rigs is stabilizing at a high level. In the North Sea, full utilization is pushing up already high daily rental rates to $240,000 for jack ups and $425,000 for semisubmersibles. In the Gulf of Mexico, jack ups are renting at $86,000/day as new units reach the market, down from $124,000 last year. But semisubmersibles are beating record rates at $515,000/day. In Southeast Asia, rig rental rates have risen by as much as 110% to $410 000/day on average.

Driven by both volumes and costs, the drilling market rose 42% in 2005-06 to about $43 billion. But in 2007 a stagnating onshore market likely will not exceed $17 billion. Rising costs should pull the offshore market up 45%, however, to $38 billion. Costs should slow in 2008 as newbuild offshore rigs reach the market, slowing the growth rate to 15-20% to $40 billion.

This year the offshore construction market was up 30% to $42 billion and should grow to $49 billion in 2008. A recent IFP study indicates the rate of new deep offshore fields coming on stream should increase threefold during 2007-12 in water exceeding 1,000 m deep, with operators preferring floating production, storage, and off-loading vessels. This presages a flourishing market over the next few years.

In the refining industry, IFP said investments increased 9% in 2007 to $57 billion, up from 4.8% last year. That will provide new capacity in 2010-11. But that will only account for 4.3 million b/d by 2012. IFP said the expansions would be "insufficient" to meet the 1 million b/d crude demand increase every year, even though they should "relieve tensions on the market in the medium term." ✦

UK supply-security study confident about gas imports

Uchenna Izundu
International Editor

The UK will have sufficient capacity in LNG terminals and natural gas pipelines to receive gas imports in the medium term, but price will determine if gas is sent to the country, a new government report concluded.

The report, developed with UK energy regulator Office of Gas & Electricity Markets (Ofgem), said LNG will play a crucial role in meeting the UK's gas needs along with pipeline gas as the country's indigenous supplies fall. "Further investment will be needed to avoid market tightness around the middle of the next decade and in subsequent years," the Department for Business, Enterprise, and Regulatory Reform said.

Use of coal, oil, and nuclear power is unlikely to be limited by resource availability, the report added, stressing that the UK could produce additional indigenous coal. Energy efficiency will be important to managing energy demand, particularly during peak periods.

However, planning delays could threaten the development of major energy projects along with the skills shortage in engineering and construction sectors to build new facilities.

Oil imports are likely to rise as domestic production wanes but present risks such as increased complexity of international routes as oil crosses more borders and resource nationalism. Transportation is expected to be the biggest consumer of oil products, while oil use by industrial and domestic consumers is expected to fall.

UK refiners face growth in demand for diesel and jet fuel and falling demand for gasoline. They must control quality of oil products and biofuels while either looking further abroad than they do now for high-quality crude or increasing investment in units enabling them to run lower-quality feedstock.

The government is confident it can access global oil supplies as UK imports increase because it has the relationships in place and an established refining industry.

Low-carbon generation

According to the report, carbon prices in the long term will attract investment in new, low-carbon power-generation capacity. "In the short term, however, uncertainty about the future of the carbon market may cause delays in investment in new generating capacity. This underlines the importance of an early and successful conclusion to discussions on Phase III of the European Union Emissions Trading Scheme, which is due to start in 2013," the report said.

Energy Minister Malcolm Wicks said it was crucial that the government not be complacent about delivering energy security. Around 14 Gw of new power-generation capacity is under consideration, and gas import capacity has quadrupled over the last few years. The report's publication coincides with news that nearly half of the country's nuclear power plants have not been working because of breakdowns and maintenance.

Jonathan Stern, director of gas research, Oxford Institute for Energy Studies, welcomed the report, stressing that it "covers a broader set of sectors and looks at security of supply from more dimensions." Stern said the consultative aspect ensured that a broad range of information was gathered to evaluate future scenarios in energy markets.

Renewable sources are expected to play an important role in meeting the power shortfall, though by how much is unclear.

Separately, Wicks indicated on Oct. 23 that the government would scale down its aspiration to source 20% of Britain's energy supply from renewables by 2020. Leaked documents reported in the national press said there were great practical difficulties in implementing the goal. The target is likely to be up to 15% instead, and Wicks said it did not mean that the UK was rejecting the EU-wide target of 20% by the same date. ✦

GAO report: CFTC's regulatory reach should expand

Nick Snow
Washington Editor

US Congress should consider expanding the Commodity Futures Trading Commission's authority over energy derivatives trading, particularly in exempt commercial markets, the General Accounting Office said in an Oct. 19 report.

The report was released days before the hearing on the CFTC's reauthorization, which is scheduled for Oct. 24 by the US House Agriculture Committee's General Farm Commodities and Risk Management Subcommittee. CFTC Acting Chairman Walt Lukken and GAO Financial Markets and Community Investment Director Orice Williams, the report's author, are scheduled to testify.

CFTC also held a day-long hearing Sept. 18 to examine regulated exchanges and exempt commercial markets. Its staff is developing recommendations, but it is not clear if they will be presented at the House subcommittee hearing.

GAO's report noted that under the Commodities Exchange Act, CFTC's authority to protect market users from fraudulent, manipulative, and abusive energy derivatives-trading practices focused on traditional exchanges such as the New York Mercantile Exchange.

It said the commission facilitates market transparency by publishing aggregate trading information for oil producers, refiners, and other large commercial traders, and for hedge funds and other noncommercial traders by compiling Commitment of Traders (COT) reports. These reports include the number of traders, changes since the last report, and open positions, i.e., obligations to take or make delivery of a commodity in the future without a matching obligation in the opposite direction.

"However, because of changes and innovation in the market, methods to categorize these data can distort the accuracy and relevance of the information to the public," GAO's report said.

Exempt markets emerge

The energy derivatives market has changed in other ways, it noted. Specifically, trading has grown on other markets, namely [over-the-counter] markets and exempt commercial markets, i.e., electronic trading facilities that trade exempt commodities, more than half of which trade in energy products, it said.

CFTC currently receives from such markets limited derivatives-trading information such as allegations of fraud or suspected manipulation and price, quantity, or other data on contracts that average five or more trades a day, according to GAO. It said the commission also might receive from OTC participants limited information such as trading records to help CFTC enforce CEA's antifraud or antimanipulation provisions.

"The scope of CFTC's oversight authority with respect to these markets has raised concerns by some members of Congress and others that activities on these markets are largely unregulated, and that additional CFTC oversight is needed," the report said. It noted that CFTC held the September hearing, where assessments included whether markets besides NYMEX serve a price-discovery function—the process of determining a commodity's price on the basis of supply and demand.

To detect fraudulent or abusive energy futures trading practices, CFTC monitors trading on NYMEX and other regulated exchanges and examines daily electronic futures trading data and other information sources, such as commercial energy commodity sources and tips from individuals on possible violations, GAO said.

"CFTC staff said they routinely investigated traders with large open positions. However, the staff added that they do not routinely maintain information about such inquiries; instead they documented their actions only when further action was warranted. This lack of information makes it difficult to determine the usefulness and extent of these activities," it said.

$305 million of fines

The report said CFTC has noted that it coordinates its enforcement actions with NYMEX as well as with the Federal Energy Regulatory Commission, US Department of Justice, and others. The commission also has taken enforcement actions in cases of attempted manipulation and other abusive energy derivative-trading practices, which resulted in $305 million in fines during 2001-05.

"While these cases have been successfully pursued, it is difficult to determine whether they have helped deter market manipulation or the other abusive practices these pursuits addressed, because the effectiveness of enforcement activities is not easily measured," said GAO. It said the White House Office of Management and Budget has concluded that the CFTC's enforcement program lacks performance measures that illustrate whether it is meeting its overall objective.

The GAO report recommended that Congress consider whether CFTC has enough enforcement authority to assure that energy commodity markets, particularly those that are exempt and provide adequately for fair trading and accurate pricing, and it made three recommendations to Lukken and CFTC itself:

It suggested that the commission examine classifications in the COT reports to determine if the categories need to be refined to improve the relevance, transparency, and accuracy of public information on trading activities.

It suggested that the CFTC explore ways to routinely maintain records of inquiries into alleged improper trading activity to more fully determine the usefulness of its surveillance, antifraud, and antimanipulation authorities.

It recommended that the CFTC more fully demonstrate the effectiveness of its enforcement activities by developing additional outcome-related performance measures that better reflect progress on meeting the program's overall goals.

In an Oct. 5 response, Lukken said that, of alternatives to regulated energy and metals trading, exchanges exist where many swap dealers trade both with commercial firms hedging price risk and with speculators taking on price risk. The overall futures positions of such traders in regulated markets do not necessarily correspond to their OTC commodity transactions, he indicated. ✦

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GLOBAL OIL RESERVES—1

Recovery factors leave vast target for EOR technologies

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Since 2003 prompt and long-term oil prices have been constantly climbing to levels ($70-90/bbl) that have caught many people by surprise. The erosion of large spare capacity in the oil chain and the perception that surging demand[1,2] will eventually outpace supplies are the two key commonly cited fundamental reasons for the escalation in prices.

At the heart of the argument is that global oil resources are scarce and stretched, hence the industry will struggle to deliver incremental supplies. This consensus view is underpinned by several themes: limited access to some hydrocarbon rich regions, two decades of a sluggish worldwide exploration record, poor expectation of finding new oil provinces, increasing number of mature basins that are on production, among others.

Resources and supplies are obviously finite, but to conclude that global oil resources are stretched or that the industry is or will be unable to replace production is a myth. Consider the fact that we have consumed less than 8% (1 trillion bbl) of the vast volumes of oil that have been discovered so far—a resource base of 9.6 trillion bbl of conventional and 3 trillion bbl of nonconventional crude oil.

Resource base is here defined as the original oil in place (OOIP) associated with proved reserves. Assuming a conservative average overall recovery factor of 22% for the conventional proved reserves of crude oil discovered to date of 2,158 billion bbl would establish a global resource base of 9.8 trillion bbl (Table 1).

Regarding the nonconventional resources, the combined OOIP for the Canadian and Venezuelan oil sands, the two largest accumulations of their kind in the world, has been reliably established at 3 trillion bbl; proved reserves of 300 billion bbl correspond to a 10% recovery factor obtained from current and future known field projects.

More resources of this type and oil shales have been quantified elsewhere. At best they are considered contingent resources—they have not yet been proven economically recoverable.

It is physically impossible to recover and produce all of the oil in the ground, but the industry is leaving behind as much as 78% of the oil discovered in fields that have been abandoned for whatever reason or in the late stages of depletion.

Looking at the future, a tenable, long-term goal would be to produce 70% of the resource base of conventional oils and 30% of the nonconventional extraheavy oils. And for this, enhanced oil recovery (EOR) techniques are the only alternative.

What is at stake is that each percentage point improvement would unlock vast amounts of oil reserves (and production) from known reservoirs and thus reduce the need to rely so heavily on new discoveries.

From a supply point of view, it is

REGIONAL DISTRIBUTION OF GLOBAL OIL RESERVES

Table 1

	Remaining reserves (1P), 2006			
	Conventional		Nonconventional	
	Billion bbl of oil	%	Billion bbl of oil	%
Middle East	734	64		
FSU	78	7		
South America	62	5	[1]128	44
North Africa	60	5		
West Africa	46	4		
North America	41	4	[2]165	56
North Sea	14	1		
Others	112	10		
World's remaining reserves	**1,147**	**100**	**293**	**100**
Cum. production	**1,011**		**7**	
World's ultimately recoverable reserves	**2,158**		**300**	
Est. original oil in place[3]	**9,800**		**3,000**	

[1]Orinoco oil belt. [2]Canadian oil sands. [3]Est. original oil in place = ultimately recoverable reserves/RF (RF is recovery factor assumed 22% for conventional and 10% for nonconventional oil).
Sources: Oil & Gas Journal, Eni, OPEC

a fact that many of the known basins are mature (either stable or declining) while fewer are growing, immature, or remain to be explored. There is no doubt that the incremental sources of supply will depend on the continued development of known resources, onshore Middle East and North Africa, unconventional oils, new offshore fields,[3] and oil from new difficult basins.

EOR production accounts for only 3% of world oil production, but in the near term its potential could be significant in extending the current plateau of world onshore and mature offshore production.[4]

The objective of this two-part article is to estimate global oil resources based on a heuristic analysis of the recovery efficiency of the existing proved reserves, with a view to determine how much these reserves can be expanded by boosting their recovery factor through technology proven EOR.

The reserves are sorted by oil gravity and depth, which are key parameters used in the screening of oil reservoirs to establish the most viable EOR techniques. The impact of EOR on future supplies is also discussed.

EOR's competitiveness

It is a simple fact that the economics of finding new oil in most regions of the world has been much more attractive than squeezing the oil from aging fields.

Global F&D[5] costs were $14.42/bbl in 2006, up a whopping 29% from the previous year. Development capex for high-end deepwater fields[6] with built-in pressure maintenance (gas and water injection) projects run between $4 and $6/bbl of added reserves, with production costs in the $3-4/bbl range.

For nonconventional oils, development costs for recent projects in the Canadian and Venezuelan oil sands range from $4.30 to $6.25/bbl of added reserves. Production costs are $6 for cold production or $17 with steam generation.

In contrast, capex for development of EOR projects is nearly $2 per added barrel, varying somewhat with field location, well depth, number of existing wells that can be converted for injection, source of carbon dioxide, etc.

EOR production costs—those above conventional operating costs—however, can be high depending on the cost of chemicals, of steam generation that uses natural gas ($10 per added barrel), and the cost of CO_2, roughly $10 per added barrel in the US. Incentives for CO_2 capture/sequestration could further lower the infrastructure costs associated with CO_2 delivery to the oil field, particularly those offshore.

The bottom line is that EOR capex is now very competitive with F&D costs and also with reserves acquisitions,[7] which averaged $12.86/bbl worldwide in 2006.

Global oil recovery factor

Oil recovery factor is the percentage of the in-place discovered oil that is technically recoverable.

The primary phase of oil production from a reservoir depends on its existing natural energy source which may be one of several (Table 2).

Solution gas drive is the most widespread natural drive mechanism in the majority of the world's reservoirs and can provide a recovery of up to 20% of OOIP. This primary process is normally supplemented early in the life of the reservoir by secondary recovery or improved oil recovery (IOR) processes consisting of stranded gas reinjection and waterflooding. Roughly one-third of the world's reservoirs have natural water drives.

When secondary recovery processes are implemented from the start of production—as is now standard practice with new oil fields—or later on during the primary phase, the process is referred to as "pressure maintenance." Although recovery rates of up to 70% are theoretically possible, values above 60% are very rare; they are more in the range of 45-50%.

Tertiary or EOR methods are applied at the end of the secondary phase. They can be thermal, miscible, or chemical processes that attempt to sweep out as much as possible of the remaining oil. The most ubiquitous of these techniques is CO_2 flooding for medium and light oils.

The 30-year history of this technology in the US and other countries indicates that it is possible to recover an additional 7-15% after waterflooding. Lake et al.[8] has an excellent review of the three major EOR processes and their limits in regard to oil viscosity, permeability, and depth of the reservoirs.

Large scale injection of standard fluids like natural gas and water to supplement the natural energy of the reservoir was not the norm in the international arena until the 1960s. Even today, the large reservoirs are the ones generally selected.

Moreover, not all IOR/EOR techniques are applicable to all reservoirs and oil types. As a result considerable numbers of reservoirs, especially in medium and small fields that account for 50% of world production, have been left without the application of secondary recovery processes.

Expected oil recovery efficiencies

Table 2

	Original oil in place, %
Primary methods	
Liquid and rock expansion	Up to 5
Solution gas drive	20
Gas cap expansion	30
Gravity drainage	40
Water influx	60
Secondary methods	Up to 70
Gas reinjection	
Waterflooding	
Tertiary methods	Up to 80
Thermal (steam, combustion, hot water)	
Miscible (CO_2, HC gases, N_2, flue gas)	
Chemical (polymers, surfactants)	

As a general rule, a recovery factor of 15-20%, corresponding to the solution gas drive mechanism, is usually the first estimate for a new discovery until other production mechanisms have been observed in the field. Case in point is the recent certification of the China Nanpu[9] offshore oil find; PetroChina had originally assigned a recovery factor of 40% and subsequently downgraded it to 20%.

Recovery estimates for heavy oils (<22.3°) range at 10-15% for primary, 20-25% with secondary, and an additional 2-6% with EOR, for a total of 30%. Extraheavy oils (≤10°) are unique. The very viscous ones may be unproducible by primary means and are subjected to steam injection from the onset as is the case of the Canadian oil sands. Their recovery factor is 10%. For Venezuela's Orinoco, primary recovery by solution gas drive (referred to as cold production) is also 10%; an additional 10-15% is estimated with EOR processes still to be tested.

How can we get an estimate of the overall recovery factor associated with the existing world reserves of more than 40,000 oil fields each with multiple reservoirs? A baseline estimate is necessary so as to determine how much room there is for IOR and EOR growth.

Several statistical estimates ranging from 27% to 35% have been mentioned in the literature. In a recent study of 11,242 fields, Laherrere obtained a worldwide average of 27%. Harper studied 9,000 fields and came up with a mean of 30%. The US Geological Survey[10] estimated a worldwide recovery factor of 40%.

An overall recovery factor for the US was reported at 22% in 1979. It had increased to 35% by 1999 and would be about 39% today if the trend continued.

The overall recovery efficiency for the North Sea province is 46%, the highest in the world thanks to sound IOR management applied throughout the life of the fields. Examples of top oil fields include Statfjord field with a record 66% recovery efficiency without EOR. Prudhoe Bay is expected to reach 47% due to early gas and water injection, followed later by miscible hydrocarbon gas flooding.

A heuristic approach to estimating an overall worldwide recovery factor based on proved reserves might be useful. Proved reserves by definition encompass everything geologic and engineering that has been applied to every oil field ever discovered.

Let's examine two cases, the US and Saudi Arabia. The US has a resource base[11] of 582 billion bbl, and Saudi Arabia[12] has 700 billion bbl. Decline curve analysis,[13] which is based on production from proved reserves, establishes URRs of 225 billion bbl and 165 billion bbl for the US and Saudi Arabia, respectively. The corresponding recovery factors are 39% and 23%.

It is worth noting that Saudi Arabia's recovery efficiency of 23% is at the level of the US average in 1979. Most Saudi reservoirs have been produced by primary and secondary methods; other IOR technologies are also being applied to reservoirs that are among the largest in the world.

Most Saudi pressure maintenance programs, however, went into effect after substantial volumes of oil had been produced from the reservoirs. In the case of supergiant Ghawar field, gas and water injection began more than 10 years after production start-up (1951).

Experience in the North Sea indicates that reservoirs with delayed pressure maintenance programs have recoveries of up to 10 percentage points less than their counterparts that start from day one.

Of the OPEC countries that together hold almost two thirds of the world's reserves, Saudi Arabia's average recovery factor of 23% is in the upper echelon. Venezuela, the OPEC member with the most experience (since the 1950s) with both secondary and tertiary recovery projects, also has an overall recovery factor of 23%. Consequently, by analogy the overall recovery factor for the bulk of the world's conventional oil reserves would at best be about 20%.

A simple weighted average among the major oil provinces gives an average recovery factor of 22%. This is well within the range of solution gas drive reservoirs (15-25%) with some added IOR technology effects, which are the most widespread in the world.

This is the recovery value used in this article to estimate the world's conventional oil resource base of 9.8 trillion bbl. The total global oil resource base would be 12.8 trillion bbl, including the 3 trillion bbl of nonconventional oil. Schlumberger's estimate[14] of global oil resources is 9-13 trillion bbl, while the American Association of Petroleum Geologists[15] estimate is 9-11 trillion bbl.

Next: Classifying the resource base and EOR's production potential. ✦

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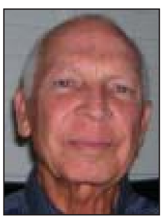

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Argentina

Two undrilled 5-km-long structural traps may contain a resource of 8.1 bcf of gas and 6.4 million bbl of oil on the 20 sq km Mina El Carmen block in the northern Golfo San Jorge basin 30 km north of Comodoro Rivadavia, a consulting geologist reported.

Marifil Mines Ltd., Spokane, Wash., holds the block, adjacent to the Restinga Ali block held by others, on which 3D seismic and geologic models led to several oil discoveries in 2004-05.

It plans to either sell the property or find an experienced oil and gas company as a joint-venture partner to develop the hydrocarbons. Drilling to test the main oil exploration targets will require holes of about 800 m depth at an estimated $400,000/well.

Oil properties just west and southwest of Mina el Carmen also produce oil, and the Golfo San Jorge basin produces about one third of Argentina's annual oil output.

Marifil owns the hydrocarbon rights under its mining claims but has continued its primary focus on precious and base metals projects.

Australia

Avery Resources Inc., Calgary, signed a formal pact with Santos Ltd. to jointly explore and develop the 631,000-acre Barta Block and the 220,000-acre Wompi Block in the Cooper basin in Queensland.

The capital program is as much as $16.3 million to shoot 300 sq km of 3D seismic surveys and drill as many as seven wells in 18 months. Avery will provide $3.9 million to earn a 30% interest in Wompi and 25% in Barta. Santos will earn 40% and 45%, respectively.

Avery's partners, Bow Energy Ltd. and Victoria Petroleum Ltd., will be entitled to the remaining interests.

The blocks are adjacent to Santos-held lands in the accelerated Cooper Oil Project.

Russia

Centric Energy Corp., London, has drilled to 3,170 m en route to the first objective horizon at 3,250 m at the South Temryuk-1 exploration well in the Azov-Kuban basin in southwestern Russia near the Azov Sea.

The first objective is to be cored, and a second objective is expected at 3,760 m in December.

On the Protoka license 120 km northeast, Centric will soon spud the Protoka-1 exploration well on a fault-bound structural closure identified on seismic.

The objectives in both wells are in the Miocene Chokrak formation, with oil expected to have been sourced by the Miocene-Oligocene Maykop series.

Northwest Territories

MGM Energy Corp., Calgary, plans to drill three wells in Canada west of Tuktoyaktuk, NWT, this winter in the western Mackenzie Delta to earn interests under a farmout agreement with Chevron Canada Ltd. and BP Canada Energy Co.

Atik P-19 is to spud by the end of December 2007, and Shavilig D-42 is to spud in late January 2008. Both wells are on EL 427B and are projected to 2,000 m or the Taglu and Aklak formations.

Langley E-07 is to spud in February or March on EL 394 to 1,400 m to test multiple stacked zones in the Upper Taglu.

MGM also plans a 150 sq km 3D seismic program in the North Ellice area of the western delta, a 160 line-km 2D program in the Ogruknang area north of Inuvik, and a 170 line-km 2D program in the Kelly Lake area of the Sahtu region northeast of Norman Wells.

Arkansas

Kerogen Resources Inc., private Houston independent, and Triangle Petroleum Corp., Calgary, plan to build on the 34,000 gross acres (20,000 net) they hold 50-50 in Conway, Pope, and Faulkner counties, Ark., in the Arkoma basin Fayetteville shale gas play.

The companies formed a new 3-year joint venture that includes a 52-township area of mutual interest in the three counties and Van Buren County that covers a large part of the core producing area of the Fayetteville. Both companies plan to drill.

One vertical Fayetteville well has been drilled in Conway County on a drill site covered by a recently acquired 12 sq mile proprietary 3D seismic survey. A second 12 sq mile 3D survey has been shot and is being merged with the first survey.

The companies plan to work with other operators to facilitate drilling by pooling, acreage purchases, and farmouts.

Texas

Gulf Coast

Tekoil & Gas Corp., Woodlands, Tex., said it arranged $8.5 million in financing it will draw immediately to begin a two-rig workover program in Galveston Bay.

Tekoil acquired 75% interest in Trinity Bay, Redfish Reef, Fishers Reef, and North Point Bolivar fields in Galveston and Chambers counties earlier this year from Masters Resources LLC and Masters Oil & Gas LLC. Production is 1,100 b/d of oil equivalent.

The properties have 34 producing wells, 33 proved nonproducing, and more than 64 proved undeveloped opportunities on 24,261 gross acres plus deep potential to 20,000 ft.

A workover in May 2007 in Point Bolivar field flowed at test rates as high as 888 b/d of oil and 164 Mcfd of gas on a 20⁄64-in. choke with 450 psi FTP.

Tekoil let a contract to Fusion Petroleum Technologies Inc., Houston, to conduct a field study using 70 sq miles of 3D seismic data.

POINT OF VIEW

PDO undertakes more complex production, development projects

Guntis Moritis
Production Editor

During his 5 years as managing director of Petroleum Development Oman, John Malcolm has seen an increase in the complexity of operations for sustaining oil production from the company's large Block 6 in Oman.

PDO produces oil and gas from about 3,750 wells in 120 fields and operates about 16,000 km of pipelines and flowlines, numerous oil production facilities, and three gas processing plants. In 2006, it used 36 drilling rigs to drill 249 oil wells in the complex geology of Oman that includes light and heavy oil accumulations in carbon-

ates and sandstones, at shallow and deep depths. Its 2007 program calls for drilling about 400 wells.

In 2006, PDO produced an average 589,000 bo/d, which was about 7% less than in the year before. Its natural gas and condensate production during 2006 was 430,000 boe/d. The company expects to produce 560,000-570,000 bo/d in 2007.

Owners of PDO include the Omani government 60%; Royal Dutch Shell PLC 34%; Total SA 4%, and Partex Oil & Gas Group 2%. In December 2004, PDO signed a 40-year extension of its concession and shareholder agreement for Block 6, which was to expire in 2012.

The shareholders of PDO have an equity stake in the oil but not the nonassociated gas resources in Block 6. The company, however, produces and explores for nonassociated gas on behalf of the Omani government under a separate agreement.

The company's first commercial oil discoveries were in the early 1960s, with first oil exported from Oman starting 40 years ago in

"If we had sweet reservoirs, we wouldn't be doing what we're doing."
—John Malcolm, Managing director of Petroleum Development Oman

PDO's timeline

1937—Concession covering the territories of Oman and Dhofar awarded to Iraq Petroleum Co. (IPC), later transferred to Petroleum Development (Oman and Dhofar) Ltd.

1951—Dhofar relinquished from concession portfolio; thereafter, company name Petroleum Development (Oman) Ltd. adopted.

1954—PDO establishes base at Duqm and makes first geological survey at Fahud.

1956-60—Exploration wells drilled at Fahud, Ghaba, Haima, and Afar without finding oil in commercial quantities.

1960—Most IPC partners in PDO withdraw from venture, leaving Oman concession to Royal Dutch/Shell Group and Partex.

1962—Oil discovered at Yibal and Natih.

1964—Oil discovered at Fahud. Decision made to develop and export oil from Yibal, Natih, and Fahud.

1967—Oil exports start on July 27. Cie. Française des Pétroles takes over two thirds of Partex's equity share in PDO, resulting in the following shareholding: Shell 85%, Cie. Française des Pétroles 10%, and Partex 5%.

1969—Dhofar regained as part of PDO concession area. Discovery at al-Huwaisah.

1972-73—Discoveries in central Oman—Qarn Alam, Ghaba North, Saih Nihayda, Habur, and Saih Rawl.

1974—Government acquires 25% stake in concession in January, increased retroactively in July of that year to 60%. Private shareholders now consist of Shell 34%, Cie. Française des Pétroles 4%, and Partex 2%.

1975-76—Central Oman oil fields brought on stream.

1977—The government and private shareholders sign a new long-term agreement providing for the development of the south Oman oil fields. Discovery at Rahab.

1978—Discoveries at Birba, Qaharir, Mahjour, Rima, Jalmud, Runib, Qata, Dhahaban South, Nimr, Jazal, Zauliyah North East, Sayyala, Suwaihat, Karim West, Nimr West, Wafra, Fayyadh, Amin, Dhulaima, Kaukab, Bahja, Jawdah, Hasirah, Anzauz, Burhaan, Ihsan, and Jameel.

1979—Discovery at Rima. NGL plant commissioned at Yibal.

1980—Company locally registered as limited liability company by royal decree under the name Petroleum Development Oman. Southern oil fields brought on stream. Discovery at Nimr.

1981—Marmul and Qaharir fields brought on stream.

1982—Discoveries at Sayyala and Suwaihat. Rima brought on stream.

1983—Discoveries at Wafra and Fayyadh. Gas found to the south of Jabel Salakh at Habiba and Rasafah. The Saih Nahayda gas treatment plant came on stream.

1984—Major new agreement signed between the government and PDO for 10-year exploration program to search for new reserves of natural gas.

1985—Marmul pilot steam plant started. Discoveries at al-Dhabi, Dhiab, Maqhoul South (gas), Yibal deep, Zareef, Hasirah, Mawhoob, Mukhaizna, Simsim, Taf Dahm (gas), Thuleilat, and Warad.

1986—Nimr production center opened. Discoveries at Yibal Deep, Lekhwair Deep, Lekhwair East, Hadh, Saih Rawl South, Sadad, Reihan, Salwa, and Zahra. Seven new fields brought on stream: Barik, Fayyadh, Zareef, Jalmud, Jalmud North, Jawdah, and Runib.

1987—Significant discoveries in Khuff reservoirs of Yibal, al-Huwaisah, Alam, Sadad, Thamoud and al-Burj. Eleven new fields brought on stream: Hasirah, Warad, Simsim, Zahra, Ihsan, Jameel, Mawhoob, Dhiab, Thuleilat, Yibal Khuff, and Al-Burj.

1988—The 50th oil field brought into production. Bahja permanent production station commissioned and a new gathering station commissioned in Yibal field. Four new fields brought on stream: Rajaa, Zumurrud, Reihan, and Ramlat Rawl.

1989—Six new fields brought on stream: Thayfut, Alam, Qarat al-Milh, Haima, Thamoud, and al-Dhabi. First reserves booking of nonassociated gas and condensate in Saih Nihayda field.

1990—Three new fields brought on stream: Amin, Sadad, and Wadi Haka.

1991—First offshore well drilled in Sawqrah Bay, 300 km from Salalah; however, no oil found, and the was well plugged and abandoned. Five new fields brought on stream: Basma, Jadeer, Yasmeen, Ghazar, and Arnab. Major gas discoveries at Saih Rawl and Barik in central Oman.

1992—Two new fields brought on stream: Al-Rodha and Hazar. The new Lekhwair production station began operations.

1993—Production reached record levels. Extensive seismic survey completed throughout Salalah. North Oman crude stabilization project started to improve recovery of natural gas. High-pressure gas injection production facility at Birba came on stream. Nonassociated gas reserves deemed sufficient to supply an LNG export scheme.

1994—Yibal butane project finished. Plans for supply of gas to LNG project completed. First carbonate-stringer oil reserves booked.

1995—Gas export facilities installed at Anzouz.

1996—PDO concluded an agreement with the government for the development of the central Oman gas fields. Construction began of Saih Rawl central gas treatment plant and the gas pipeline to the LNG plant at Qalhat.

1997—Major new oil credited to Al-Shomou and the Harweel Deep carbonate stringers near Birba.

1998—Cost reductions implemented as a consequence of historically low oil prices. Another carbonate stringer field—Sarmad—discovered. Maurid, Maurid NE, Wazar, Arnab, and Tuqaa fields brought on stream.

1999—Upstream LNG project completed. Ghafeer field discovered.

2000—Sakhiya field discovered. Al Noor, Mukhaizna, and Burhaan come on stream. Permanent accommodation centers opened at Fahud and Nimr, improving living conditions of PDO's contractor staff.

2001—PDO maintains record of supplying 100% of gas demanded by its customers. Kauther gas field is discovered. PDO opens a virtual reality center enabling 3D models of underground rock formations to be viewed from all angles.

2002—PDO reorganized and merged the hydrocarbon producing assets into two major operating units—North and South—each led by a director.

2003—PDO celebrated 25 years of providing an uninterrupted supply of gas to the nation. It established a study center to deepen the company's understanding of its reservoirs. Sixty Bedouin-owned local community contractors were awarded contracts.

2004—A new directorate was established specifically to plan and carry out enhanced oil recovery projects. First oil was produced from the Harweel cluster of fields, and approval was given to carry out enhanced oil recovery projects.

2005—Four oil fields discovered; two in the north at Ufuq and Dafiq and another two in the south at Sakhiya-Southwest and Mamour. The Saih Nihayda gas plant (SNGP) began supplying gas to the Oman LNG plant near Sur in March 2005, and gas from SNGP was delivered to the just-opened Qalhat LNG plant, also near Sur, through a new 48-in. pipeline that was designed and laid by PDO.

2006—First-of-its-kind service contract signed for the development of PDO's Karim small-field cluster, which gives the contractor company Medco Energi effective control of the field's operations while retaining the ownership of the fields and their reserves with PDO.

2007—Oman marks the 40th year of oil exports. First steam injected in Amal West pilot. Contracts let for constructing the Qarn Alam and Marmul EOR projects.

Source: PDO

1967 (see timeline in accompanying box). PDO's oil production peaked at an average 846,000 b/d in 1997.

Reservoir complexity

Malcolm said as fields in Oman have matured, PDO has started relying on a wider range of development options and operational strategies for ensuring long-term production capacity.

As a gross generalization illustrating the change, Malcolm said that during the 1970s to mid-1990s PDO was highly successful in finding and developing new accumulations. "Find them, drill them, and hook them up quickly." Also during this time various optimization technologies, secondary recovery, and the use of 3D seismic tremendously helped reach record oil producing rates, he said.

By the mid-1990s, Malcolm noted "PDO stopped finding fields that could be easily hooked up." For instance, in 1997 it found Harweel, the first in a cluster of high-pressure, sour-oil fields at depths ranging between 3 and 5 km. For such fields, the time between finding, appraisal, developing, and producing has increased because of their complexity, he said.

As discussed in more detail in the article, on p. 56, describing some of PDO's planned enhanced oil recovery projects, the company will be injecting miscible sour gas to produce the cluster

Career highlights

John Malcolm has been managing director of Petroleum Development Oman (PDO) since November 2002.

Employment

Malcolm in 1975 began his industrial career in the British heavy chemicals industry with positions in process control systems, project engineering, and operations-maintenance. In 1981, he moved to the Middle East and worked on engineering upgrades for a major refinery. After a 2-year break from industry to engage in teaching, research, and consultancy at Heriot-Watt University in Edinburgh, he joined Shell in January 1986.

His first position with Shell was in PDO, as the head of instrumentation and process control. Later, he became the head of central engineering at PDO. After 2 years in Oman, he was assigned to Shell's central office in the Hague, working on front-end prospect engineering, operational reviews, and a major standardization drive within Shell EP.

Next, he joined Shell Exploration & Production (UK) Ltd. in Aberdeen where he was a project manager for several engineering projects before returning to Shell's Hague office to work on redesign, transition, and management of Shell's Research and Technology center. He later held the position of vice-president.

This assignment was followed by an appointment as deputy director for the Far East and Australasia.

In 1999, Malcolm became general manager of Al Furat Petroleum Co.—a Damascus-based joint venture of Syria Petroleum Co., Shell, and Petro Canada. Later he was also appointed as the general manager of Syria Shell Petroleum Development.

In late 2002, he returned to Oman as managing director of PDO.

Education

Malcolm has a BSc in electrical and electronic engineering and a PhD in process control engineering, from Heriot-Watt University, Edinburgh.

Affiliation

Malcolm is a Fellow of the Institution of Engineering and Technology (FIET).

of fields near Harweel. To bring these fields on stream, PDO needed about 5 years of study, which included 3 years of development and production during Phase 1. Currently under construction is the $1 billion Phase 2AB of the project that will start producing the cluster of eight fields containing 10 intrasalt carbonate reservoirs.

PDO expects the Harweel cluster production to reach 60,000 b/d in 2010, with the potential to increase to 100,000 bo/d in the next decade.

Malcolm said that "if we had sweet reservoirs, we wouldn't be doing what we are doing."

Besides miscible sour-gas injection, PDO now is pursuing a host of other enhanced oil recovery projects that involve steam and chemicals for producing more of the company's estimated 50 billion bbl of oil initially in place, about 15% of which already has been recovered.

With the long-term in mind, Malcolm said, "We have been working closely with several parties that have proven EOR experience, including the Shell EOR center of excellence now established in Oman. Although EOR may still be regarded as being in the distant future by many oil companies in the region, it is inevitable. Oil fields—even prolific ones—are eventually going to need thermal, chemical, or gaseous means of extracting oil."

Field evaluations

In 2003, PDO established a study center for providing a better understanding of the company's reservoirs. Malcolm said that the center has completed studies on about 70% of the oil initially in place in PDO's 120 fields and is at a stage where it will start reassessing some field development plans.

The studies look at the future of a field for at least the next 5-10 years so that PDO can make decisions on proper technology for improving the field performance.

Staffed initially with mostly expatriates from Shell, the center's staff now is 30-40% Omani. The work is done by integrated teams of reservoir engineers, geologists, petrophysicists, well engineers, and petroleum engineers.

"Doing things in country is very important, from both the country's and company's point of view. Links between the study center and assets are so much better than if separated by 1,000s of miles, allowing knowledge to move easier between them," he said.

In the early 1990s, the production from the company's existing fields with existing hardware declined at an average year-on-year rate of 10%, but this decline rate grew to 17-18% in early 2002, Malcolm said. In the past those decline rates could be more than offset by the production of "new" oil from additional reservoirs and additional wells, but that is no longer the case.

Still, with the better understanding of reservoirs, better reservoir monitoring and management methods, and better operational practices, the decline rate has been reduced even as the production water has increased, from 2 bbl of water/1 bbl of oil produced in 1992 to about 7-8 bbl of water/1 bbl of oil today.

In the next 5 years, PDO's plans include expanding or initiating 15 waterflood projects; beginning in 2010, it will be completing one major field development project per year for the rest of that decade.

Contracting strategies

To gain efficiency, PDO has changed many of its contracting strategies. Malcolm said "Many things done 20 years ago in the way we contracted were appropriate for that time. But the last 20 years have seen massive changes and we have to look around for innovative contracting philosophy."

For instance, PDO now contracts Chinese rigs and seismic crews as well as Indian hoists and continues to look

all over the world for contractors that can work in an effective and safe manner, Malcolm said.

PDO also has started to do its own front-end engineering, to provide more flexibility in project construction, especially if the market changes, Malcolm said. One illustration of the effectiveness of doing work in-house is the company's Qarn Alam thermal project, for which the bids last year came in too high. Because of its in-house work, PDO could divide the project into segments that could be managed by smaller contracting firms, at much less cost, Malcolm said.

The company also has started awarding service contracts for operating smaller noncore fields, although keeping equity ownership in the oil. Its first contract was signed in 2006 with MedcoEnergi International, an Indonesian company.

The service contract lets Medco and its partners accelerate development of a cluster of 18 small fields in the Nimr-Karim area of south Oman, so that PDO can devote more attention to its portfolio of large fields, Malcolm said.

PDO is now going ahead with a second such service contract covering the Rima satellite cluster, which produces 2,100 bo/d from nine fields. The contract also includes another nine undeveloped fields. PDO estimates that these fields contain 650 million bbl of oil in place.

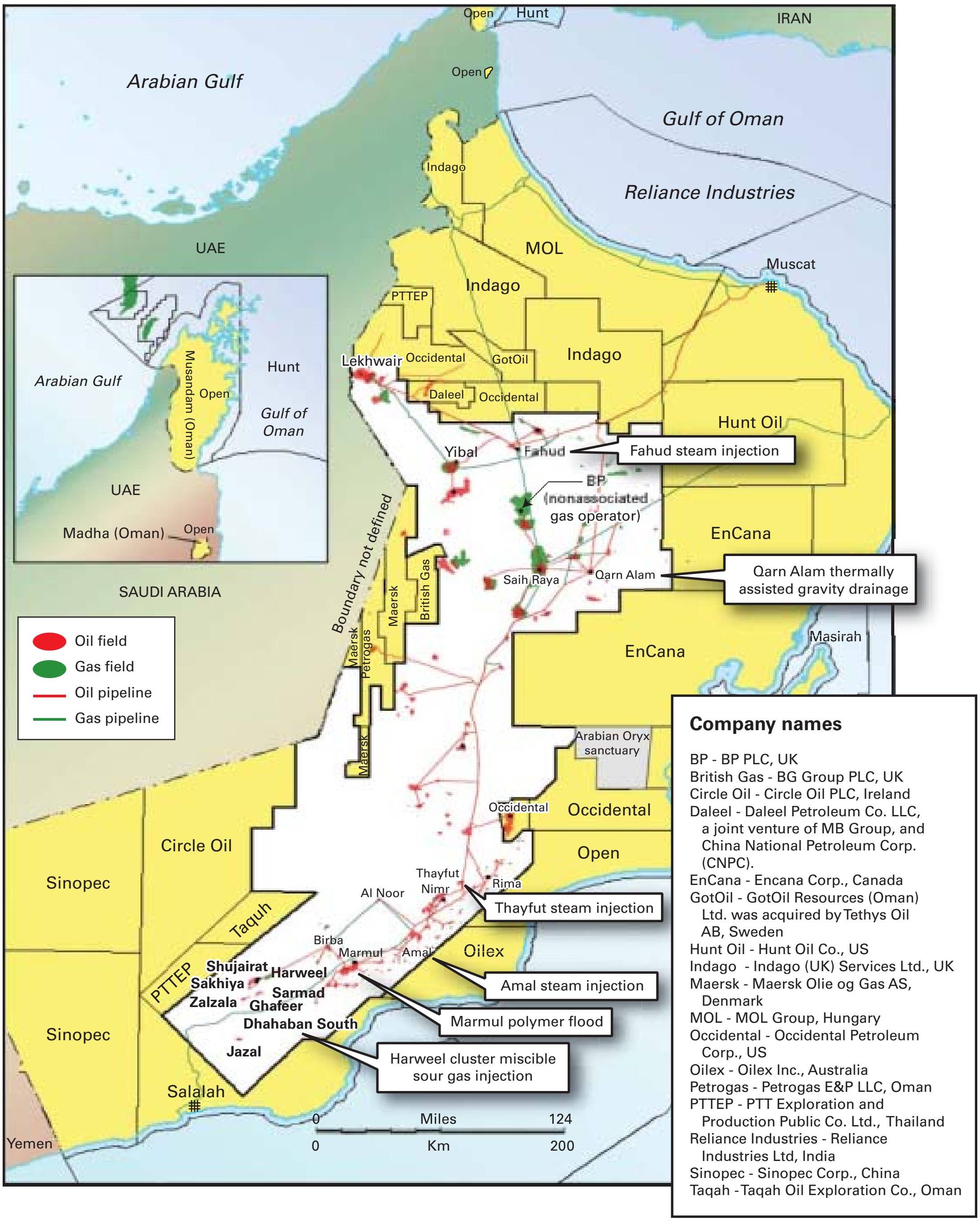
Malcolm said such contracts "pull in a broad range of people from both small companies and service companies with the hope that they will have new bright ideas."

PDO also has an active local community contracting program that gives local contractors a chance to bid on various projects. Malcolm noted that one local contractor that began building fences for PDO many years has now grown into an international company that recently had an initial public offering of its stock. ✦

PDO initiates various enhanced oil recovery approaches

OMAN ACTIVITY

Fig. 1



Guntis Moritis
Production Editor

To sustain long-term oil production from its contract area in Oman, Petroleum Development Oman has turned to diverse methods for enhancing oil recovery from its fields that contain many billions of barrels of oil in place.

Without these investments, PDO expects ultimate oil recoveries from these fields would range between 4 and 20%. But depending on the EOR method employed, ultimate recoveries could increase to as high as 50%.

The company's first EOR projects will be in fields near Nimr, around Harweel, in Qarn Alam, at Marmul, and at Fahud (Fig. 1).

Near Nimr, PDO started injecting steam on Sept. 10, 2007, in a pilot project in Amal West field and will

Production

also begin steam pilots in Amal East and Thayfut. Also it is studying the potential of in situ combustion in a shallow reservoir containing 300-700 cp oil in Nimr.

The company also has under way facility construction for injecting miscible sour gas into a cluster of fields near Harweel.

At Qarn Alam, PDO in early 2007 let contracts for constructing facilities for a thermally assisted gas-oil gravity drainage (TAGOGD) project in a heavy-oil fractured carbonate reservoir.

Another contract let in 2007 was for facilities for injecting polymer in a heavy oil reservoir at Marmul.

At Fahud, the EOR process, also TAGOGD, will involve injecting steam to accelerate recovery of light oil from a fractured carbonate.

PDO is owned by the Omani government, 60%; Royal Dutch Shell PLC, 34%; Total SA, 4%, and Partex Oil & Gas Group, 2%.

Nimr area

PDO is initiating three steam injection pilots in fields in the Nimr area (Fig. 1) that will assess the process for recovering heavy oil from thick sandstone reservoirs in Amal West, Amal East, and Thayfut fields. Steam injection in a well at Amal West started in September 2007 (Fig. 2).

PDO designed the pilots to calibrated simulation models for designing the projects, although a pilot in Amal East in the late 1980s and early 1990s provided it with enough information to feel confident that steam injection is feasible in the fields, Amour al Suqri, the head of engineering construction for the Nimr projects, told OGJ during a recent visit to the site.

The company plans to complete full field steam-injection facilities in 2010 and later in 2013 add a power plant for providing additional heat for steam generation.

The Amal fields produce a 20-22° gravity heavy oil from beam pumped wells with depths that vary from 500 to 1,000 m.

PDO constructed an 800 cu m/day water treatment plant for the Amal West and Amal East pilots. The plant includes a GE reverse-osmosis process that lowers total dissolved solids in the feed water to 50 ppm from 4,000 ppm (Fig. 3).

Steam injection in the Amal West pilot started during September 2007 (Fig. 2). Photo by Guntis Moritis.

Two skid-mounted 200 ton/day portable gas-fired steam generators provide the steam (Fig. 4).

The Amal West pilot was a fast track 18-month project from initial assessment to steam injection. PDO said it initiated the project in first-quarter 2006, with approval given in third-quarter 2006, and detail design started in first-quarter 2007.

The Amal West pilot has three wells on cyclic injection that will have steam injected in them for 1 month, followed by 1 week of soaking, and 3-5 months of production. PDO expects the full-sized project in Amal West to involve continuous steam injection with wells on seven-spot, 10-acre patterns.

For the Amal East pilot, PDO plans to move one of the 200 ton/day steam generators from Amal West. The pilot also will use three wells.

Al Suqri said the reservoir in Amal East is deeper, so that higher pressures will be needed to inject steam. The reservoir is about 200-m thick.

For the full-scale project, the company expects Amal East to remain on cyclic steam injection until the reservoir heats up sufficiently for continuous steam injection.

PDO also plans to inject steam at Thayfut. Its pilot involves 1 well on continuous steam injection and cyclic

A reverse-osmosis process lowers the total dissolved solids in feed water going to the steam generators at Amal West (Fig. 3). Photo by Guntis Moritis.

Two, 200 ton/day, skid-mounted steam generators produce the injected steam in the Amal West pilot (Fig. 4). Photo by Guntis Moritis.

steam injection in four other wells.

The wells are at 900-1,000 m depths. Steam injection will be 200 tons/day.

PDO also has under evaluation an in situ combustion project in a shallow reservoir containing 300-700 cp oil in Nimr. The reservoir contains heavy 20° gravity oil and has strong aquifer support.

Harweel

In the south of Oman, PDO has under construction the facilities for the Harwell Phase 2AB miscible sour-gas injection project (Figs. 5 and 6). PDO awarded the engineering, procurement, and construction (EPC) contract in December 2005 and expects to finish construction in 2010.

PDO discovered Harweel in 1997 and since has found seven similar fields containing intrasalt carbonate stringers in a large 1,000 sq km area. The company estimates that the cluster of fields contained an initial 1.8 billion bbl in place of light sour oil and retrograde condensate. The fields in the cluster include Shujirat, Sakhiya, Harweel Deep, Sarmad, Ghafeer, Dafiq, Dhahaban South, and Zalzala

The oil has a 38-50° gravity and a 300-400 cu m/cu m GOR. The associated gas contains about 5-10% CO_2 and 5% H_2S.

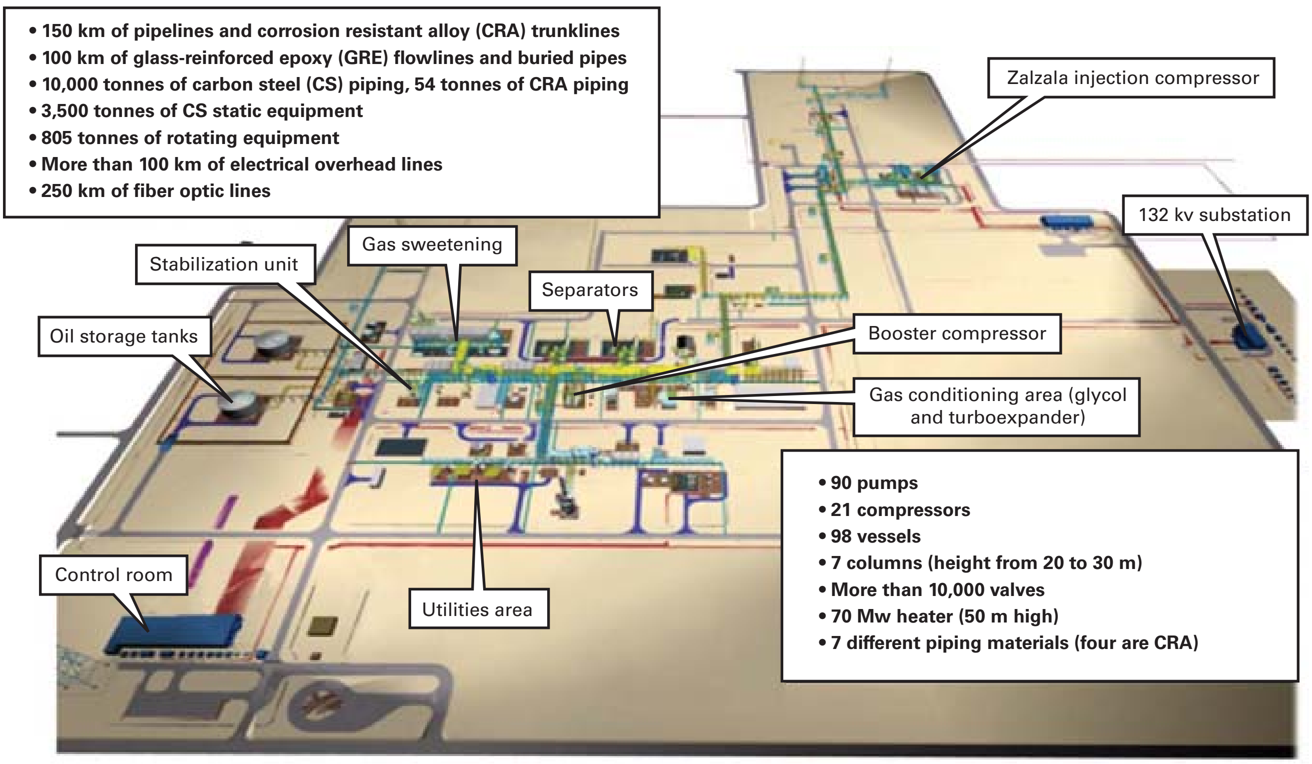
The reservoirs are at a 3-5 km depth and have a high 7,000-14,000 psi pressure. The stringers commonly have a low 0.1-10 md permeability.

PDO has drilled more than 60 wells in these fields and in Phase 1 has produced oil from four fields and injected gas in the Zalzala field to confirm the viability of miscible sour-gas injection.

During Phase 1, PDO produced about 18,000 bo/d from the Harweel cluster of fields. But production could increase to more than 100,000 bo/d

HARWEEL 2AB SCOPE

Fig. 5



Source: PDO


WIRZ
How can I unlock
more value from mature assets?

Miscible sour-gas injection facilities are under construction for the Harweel cluster (Fig. 6). Photo from PDO.

once the Phase 2AB project is finished.

"The crude oil found in the cluster is some of the oldest on earth," said Harweel Project Manager Ian R. Hill during an interview at PDO headquarters in Muscat.

Hill estimates a 10% ultimate oil recovery without miscible sour-gas injection that may increase to more than 30% with injection.

In 2005, PDO signed a $1 billion EPC contract with Petrofac for an oil and gas processing station as well as gas-injection facilities near Harweel for the full-scale EOR project. Petrofac is executing the work from its Sharjah base in conjunction with Galfar Engineering & Contracting, an Omani company.

The central processing facility will include one of the highest-rated, largest-capacity gas-injection compressors in the oil industry.

The Harweel facilities will process very corrosive fluids, so that much of the installed equipment and piping is made from corrosion-resistant alloys.

Zalzala field will be first to go on stream once the full-scale EOR project begins. The Sakhiya and Dafaq fields will be added later, although both will be on primary production before miscible sour-gas injection starts.

Qarn Alam

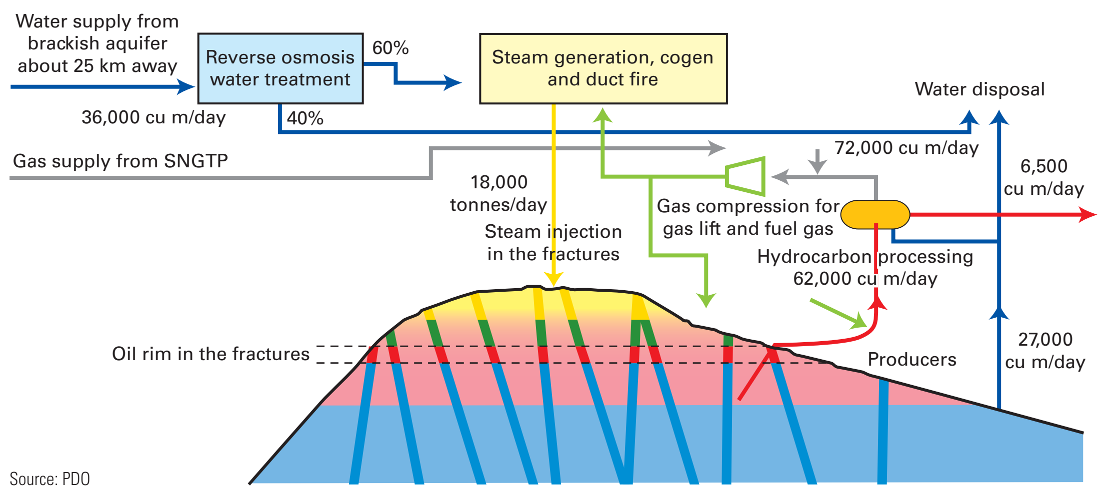
PDO discovered Qarn Alam in 1972 and estimates that initial oil in place in the field's fractured carbonate reservoir was 1 billion bbl. The field produces heavy 16° gravity, viscous 220-cp oil. Without the thermal project, PDO estimates only a 4% ultimate oil recovery from the field. But with its thermally assisted gas-oil gravity drainage (TAGOGD) project ultimate recoveries may exceed 32%, according to the company.

Qarn Alam Project Manager Rik Hofland told OGJ a steam pilot during 1998-2003 proved out the injection concept. The TAGOGD process involves injecting steam into the formation's fractures to heat the low-permeability oil-bearing rock (Fig. 7). The heat liberates gas that reduces the oil viscosity, allowing the oil to flow easier.

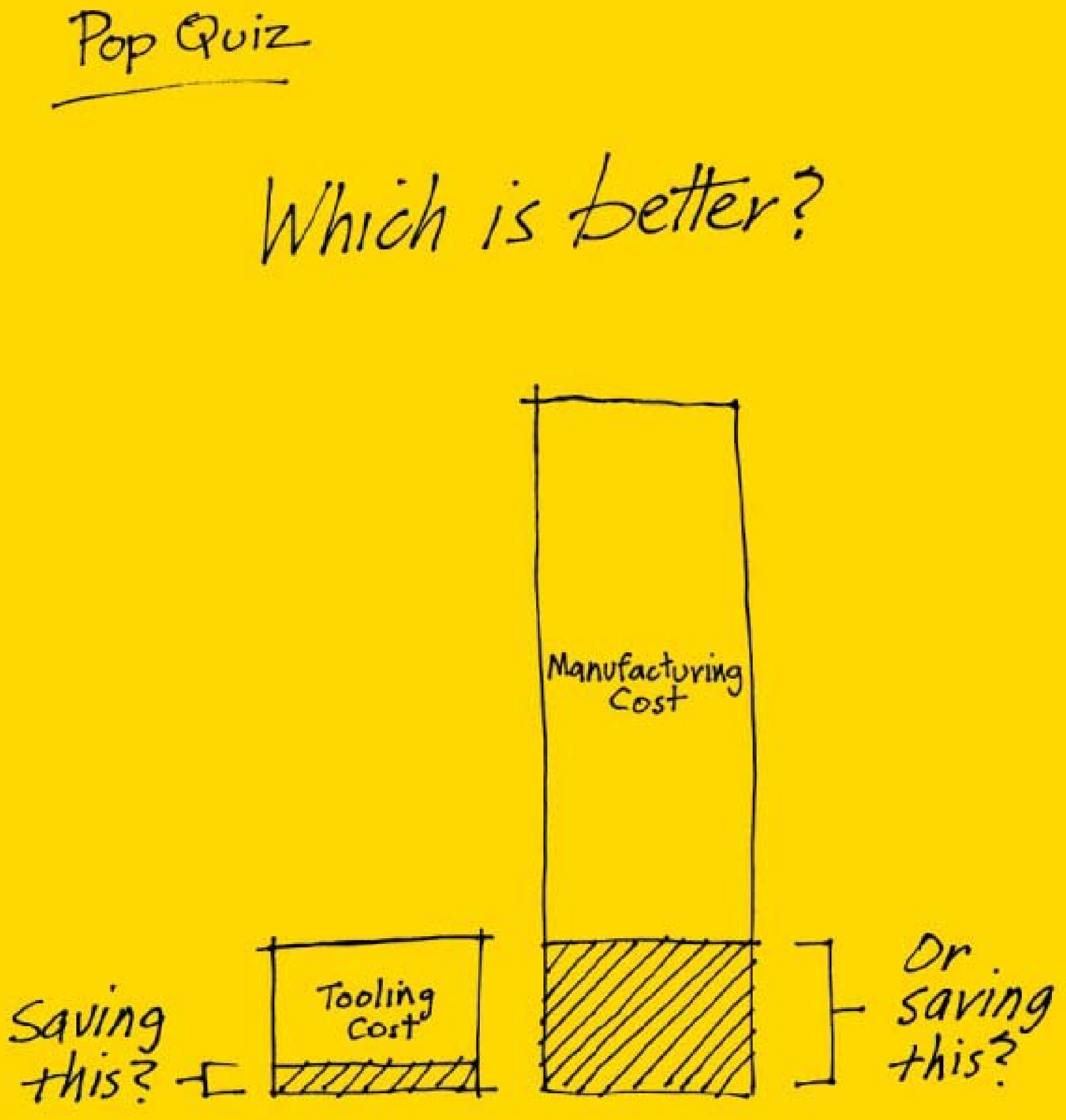
Hofland says the fractures serve as conduits for both the injected steam and the produced oil, but unlike a conventional

QARN ALAM STEAM PROJECT

Fig. 7

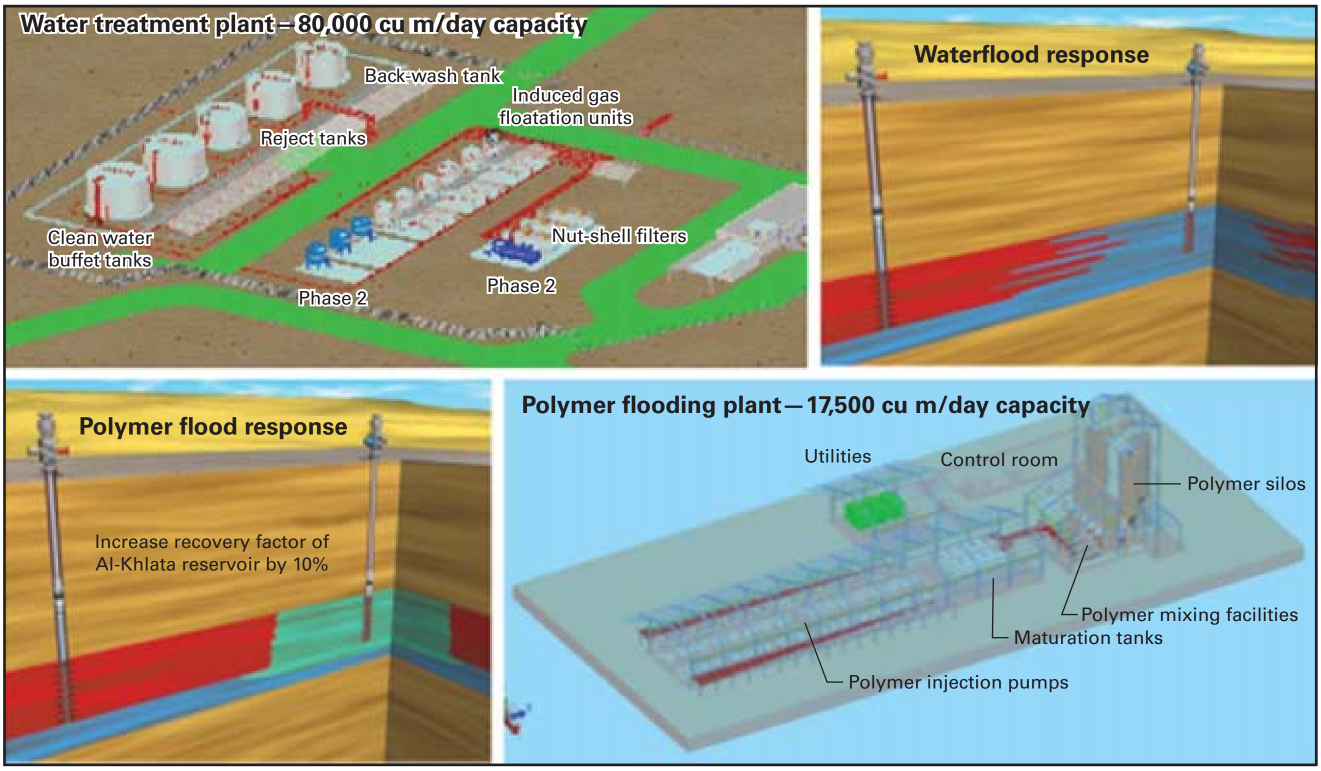


Source: PDO


Pop Quiz
Which is better?
Manufacturing Cost
Tooling Cost
Saving this?
Or saving this?

MARMUL POLYMER FLOOD

Fig. 8



Source: PDO

steam-injection project, in which the steam serves to drive oil to producing wells, the steam at Qarn Alam provides heat to enhance the existing gravity drainage mechanism. This feature allows the project to have only a few injection wells.

The company's plan is to inject during the next 30 years 18,000 tonnes/day of steam and have a plateau production during 10 years of about 30,000 bo/d.

The project involves drilling 149 new wells that include:

- 69 water supply, aquifer pump off, and water-disposal wells.
- 15 steam injection wells.
- 36 producing wells.
- 29 observation wells.

Earlier in 2007, PDO let two EPC contracts for building facilities for the project.

Facilities will include three heat-recovery steam generators, a 36,000 cu m/day reverse-osmosis plant, and equipment to handle 62,000 cu m/day of gross produced fluid and dispose of 72,000 cu m/day of water.

The project will have 220 km of pipelines and flowlines, along with a power plant.

The main oil-bearing reservoir is the Shuaiba-Kharaib formation that has a dome-shape and a 6 by 3 sq km areal extent. The maximum oil column thickness is 165 m, with the shallow crest of the Shuaiba at 350 m below ground level.

The reservoir has a high 29-34% matrix porosity. Matrix permeablity in the Shuaiba ranges from 5 to 20 md while in the Kharaib it is 1-10 md.

PDO awarded the EPC contract for the on-plot facilities, those erected at the field site, to Dodsal and the off-plot facilities, the oil and water flowlines and associated hardware outside of the field site, to Galfar Engineering & Contracting.

"Most of the steam will be generated by waste-heat recovery from the existing Qarn Alam power station, thereby reducing the project's CO_2 emissions and saving on gas consumption," said Subsurface Project Team Leader Khalid al Khabouri.

The start-up date of all facilities will be around 2010.

Marmul

Initial production from the Al Khlata sandstone reservoir in Marmul started in 1980, although the field was discovered in 1956. The reservoir was on primary production until a waterflooding started in 1986, with full field waterflooding starting in 1999. Marmul Polymer Project Manager Fakhri al Sukaiti said a polymer project in the 1980s indicated the feasibility of injecting polymer, although subsequent low oil prices led to deferring the project.

Although waterflooding improved recovery, al Sukaiti said that "because the oil is highly viscous (80-90 cp at the 45° C. reservoir temperature), the injected water tended to flow past and leave behind much oil."

With its planned polymer flood, al Sukaiti expects to obtain 10% more recovery from the field.

Polymer flooding uses polymer to make the injected water more viscous so that it can more effectively sweep the remaining oil from the reservoir. PDO plans to obtain the polymer from France in powder form and ship it to the field in bulk containers.

The injection mixture will have 15 cp viscosity.

PDO, in February 2007, awarded an EPC contract for the Marmul polymer flooding project to France's SNF with the UK's Mott MacDonald as design contractor and Oman's Bahwan Engineering Co. as construction contractor.

The contract involves building centralized water treatment and polymer preparation and injection facilities as well as the supplying chemicals for 5 years. Project completion is scheduled for 2008.

The centralized water-treatment facilities will include a primary produced-water treatment plant with capacity of 80,000 cu m/day and a secondary produced-water treatment plant with capacity of 30,000 cu m/day (Fig. 8).

The polymer preparation and injection facilities station will have a capacity of 17,500 cu m/day.

Fahud

PDO plans to start injecting steam into one reservoir in Fahud in 2008 as part of a pilot project that kicks off another TAGOGD development. Fahud produces 33° gravity oil from the Natih fractured carbonate and is PDO's oldest and largest field in northern Oman. Discovered in 1963, the company estimates the initial oil in place in the shallow field was 6.3 billion bbl.

The field has about 380 producing wells.

But, as John Malcolm, PDO's managing director, says, "just because a field has been producing for many years, it does not mean there is no more scope for gaining additional reserves from it. EOR techniques can be applied to it to give it a new lease of life."

Like the TAGOGD project at Qarn Alam, the one at Fahud will involve injecting steam into the fractures of a carbonate reservoir. But the Fahud project will be the first time ever that the recovery technique is applied to produce a light oil.

PDO made its investment decision on steam injection in September 2006 on the basis of the performance of earlier water-injection projects and a thorough review of the development options for the mature field. To minimize the business risk, the field will be developed according to a prudent phase-by-phase approach.

The company says the oil recovery factor from the field is about 17% and expects steam injection to add 10% to the ultimate oil recovery. ✦

World's largest CO_2 capture, EOR project planned off Dubai

Guntis Moritis
Production Editor

Among the projects Dubai Petroleum has under way is a feasibility study for injecting CO_2 to extract more oil from mature oil fields. The company expects the venture will become the world's largest CO_2 capture and EOR project.

Besides the EOR project, the company's other plans for increasing oil and gas production off Dubai include contracting additional drilling rigs, developing a gas discovery, debottlenecking producing facilities, and optimizing reservoir performance.

Dubai Petroleum operations

Dubai Petroleum Establishment is the new state oil company that on Apr. 2, 2007, took over operations for a concession area off Dubai that previously a ConocoPhillips consortium operated since signing a concession agreement on Aug. 3, 1961.

The consortium made its first oil discovery at Fateh field on June 23, 1966. Fateh lies about 160 km northwest of Dubai in the Arabian Gulf (Fig. 1).

The field is a 73 sq km folded structure, with a vertical relief of 250 m, and contains numerous carbonate reservoirs. The Cretaceous Mishrif formation carbonate reservoirs are the most prolific, having produced 60% of the oil lifted to date (Fig. 2). At Fateh, the Mishrif reservoirs are not present over the crest of the structure, due to erosion.

Other producing reservoirs include the Thamama and Ilam carbonates.

Mishrif reservoirs contain a light 33° gravity oil with 25 ppm H_2S. First oil lifted from Fateh was on Sept. 22, 1969. Other fields discovered in the concession are SW Fateh on Oct. 26, 1970, Falah on Aug. 10, 1972, and Rashid on Aug. 17, 1973.

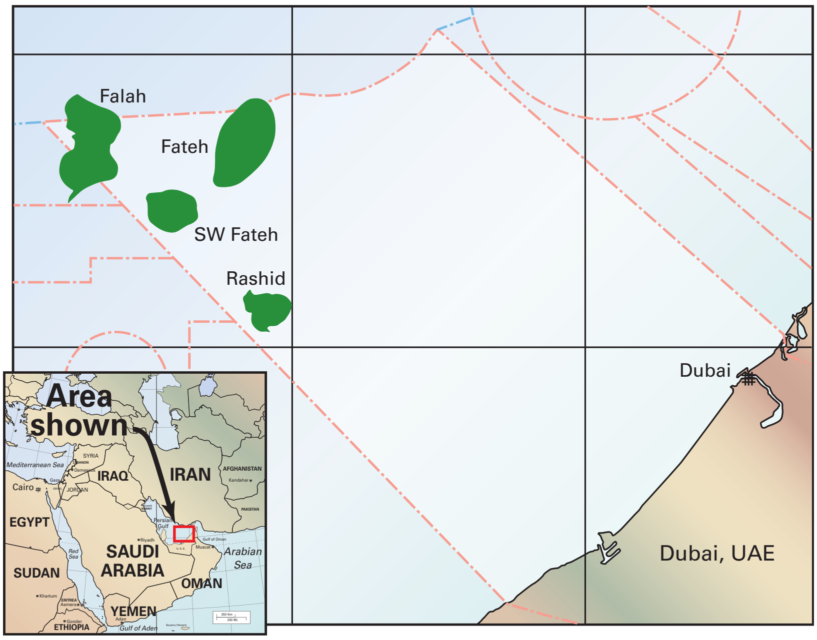
Secondary oil recovery using seawater injection commenced in the fields on June 8, 1974. Currently, the fields have about 240 active oil wells and 120 active injection wells. The oil wells produce on gas lift, with 17 compressor trains providing 1 bcfd of gas-lift capacity.

Field facilities (Fig. 3) include 71 processing, compression, water injection, and wellhead platforms, of which 4 are manned, and 317 miles of pipelines.

Final separation and storage occurs in three submerged steel vessels called

DUBAI FIELDS

Fig. 1



DUBAI STRATIGRAPHY

Fig. 2

System	Series	Formation	Lithology	Pay zone	Average thickness, ft	Description
Tertiary	Pliocene and Miocene	Upper and Middle Fars			1,100-1,600	Anhydrite, gypsum, shale, and limestone
Tertiary	Miocene	Lower Fars			2,000-3,600	Anhydrite, shale, and limestone, some salt
Tertiary	Oligocene	Asmari		☼	470-650	Limestone and dolomite
Tertiary	Eocene	Damman			1,600-2,200	As above
Tertiary	Eocene / Paleocene	Pabdeh		⌖	900-1,600	Argillaceous limestones and dolomites
Cretaceous	Upper	Aruma		⌖	650-3,200	Shales, marls, and limestones
Cretaceous	Upper	Ilam		●	230-275	Chalky packstones and wackestones, occasional grainstones
Cretaceous	Upper	Laffan			12-80	Shale
Cretaceous	Upper	Mushrif		●	Variable due to unconformity	Rudist grainstones
Cretaceous	Upper	Khattyah			18-435	Basinal limestones
Cretaceous	Lower	Mauddud			60-75 (up to 160)	As above with more with increase in shale
Cretaceous	Lower	Nahr Umr			200-400	Shale
Cretaceous	Lower	Thamama group: Shuaiba		●	150-240	Limestone (reefal) Rudist shelf limestones
Cretaceous	Lower	Thamama group: Zone II		●	150-170	2,250 ft as above
Cretaceous	Lower	Thamama group: Zone III (A-H)		●	700-800	
Cretaceous	Lower	Thamama group: Zone IV		●	260	
Cretaceous	Lower	Thamama group: Zone V			450	
Cretaceous	Lower	Thamama group: Basal oolite (VI)			Variable 0>400	Dolomite with pellet ghosts and oolites
Jurassic	Upper	Hith equivalent			200	Dolomite and some anhydrite
Jurassic	Upper	Arab D - Arab B			600	Limestone and dolomite
Jurassic	Upper	Divab			400	Limestone
Jurassic	Lower-Mid	Arab group: Upper Arab J			200	Limestone and dolomite
Jurassic	Lower-Mid	Arab group: Uwainat			175	Limestones
Jurassic	Lower-Mid	Arab group: Lower Arab J			265	
Jurassic	Lower-Mid	Izhaft J			800	
Jurassic	Lower-Mid	Hamlah			160	
Triassic		Gulajlah			860	Shale and salt
Triassic		Sudair			810	
Permian		Khuff		☼	2,700	Anhydrite and dolomite H_2S
Permian		Prekhuff clastics Wajib		☼	300	Well rounded quartz sand Sweet C_1

mature oil fields.

The company says experimental testing, in 1999, showed that WAG injection with associated gas on the western flank of Fateh field could improve oil recovery, but further investment stalled because of limited injection-gas availability.

Its new plan would capture up to 13,000 tons/day of CO_2 from some onshore power plants and then compress and transport the gas for injection into offshore producing reservoirs.

The company says the project would require much investment in new offshore wellhead platforms, processing and storage facilities, and pipelines capable of handling CO_2-contaminated fluids. It expects a large new revenue stream from the increased oil production with the additional benefit of storing captured CO_2 in underground reservoirs at the end of the project.

If the project gets the green light, the venture would become the largest capture and injection WAG scheme in the world, with the first phase of CO_2 injection commencing by yearend 2012, the company says.

"Khazzans," which sit on the seabed. Also the Al Wasel floating storage unit provides additional storage.

Lifting of export oil is handled offshore through two single-point mooring buoys.

Dubai Petroleum says the most oil lifted in a month occurred during December 1989, with 14 million bbl lifted.

CO_2 injection

Dubai Petroleum has under way a feasibility study for injecting CO_2 in a miscible water-alternating-gas (WAG) scheme to extract more oil from its

Fields off Dubai include (top left) Fateh, (top right) Falah, and (bottom photo) SW Fateh (Fig. 3). Photos from Dubai Petroleum.

Conventional drilling

Dubai Petroleum also plans to contract additional drilling rigs. Its strategy includes continuing to use the Nobel Roy Rhodes jack up drilling rig, which has been operating in the field for 19 years, to drill conventional sidetrack horizontal wells in pursuit of unexploited oil pools and has brought in a second jack up, the Mark Burns, for drilling additional wells.

It has also contracted for one hydraulic workover unit recently and expects to contract another hydraulic workover unit and jack up rig in early 2008.

By 2008, therefore, it will have five drilling units working off Dubai, something that has not been seen for many years, the company says.

Gas production

Increased energy demand in Dubai has led Dubai Petroleum to begin an aggressive program for exploiting potential gas accumulations. Its first well drilled after taking over concession operations appraised the potential gas resources in the Tertiary Asmari limestones.

The company says the well was a successful test and was hooked up for producing new lean gas in only 6 weeks after the company started operations.

First gas flowed to shore on May 23, 2007.

The company commenced in July 2007 further appraisal drilling of a potentially larger accumulation of Asmari gas at SW Fateh.

Debottlenecking

Increased production of water and lift-gas constraints limit production from some areas of the fields. Dubai Petroleum plans to eliminate these bottlenecks before drilling additional wells.

In the case of Falah field, which has a low recovery factor compared with other fields, the company has studies under way to determine the extent to which investment in electrical submersible pumps, multiphase pumps, new gas compression and export pumps, power generation, and additional separation can add production capacity.

It also has plans for extensive field tests for optimizing production in regards to high water-cut wells and gas lift.

Another project planned for 2007 and 2008 is a logging campaign targeting the under-performing Ilam reservoirs.

Company organization

Since being created, Dubai Petroleum has recruited a new staff with the skills and experience to replace the departing operating staff.

Besides staffing the general and development management sections of the organization, the company also has contracted Petrofac Management International Ltd. to handle facilities management including drilling and production operations.

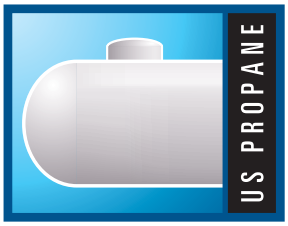
The total company workforce including Petrofac employees is now about 650.

The company says that the entire transfer process from the previous operator was completed within 6 months, including the introduction of new business information systems. ✦

SECOND-THIRD QUARTERS 2007

Low C_3 inventory build fuels supply concerns for heating

Dan Lippe
Petral Worldwide Inc.
Houston



A slump in waterborne propane imports into the US during second and third quarters 2007 caused an inventory deficit to widen. For the 2007-08 winter heating season, the deficit itself is the critical supply parameter that defines the supply outlook for US propane markets.

Propane supply for the US winter heating season depends on domestic production, imports, and inventory in primary storage.

Primary storage facilities are those that report their inventories to the Energy Information Administration (EIA) weekly and monthly. From the perspective of propane retailers, propane inventory statistics are the most widely reported of the three sources of supply and are viewed as the critical supply parameter.

At the end of March 2007, EIA's Petroleum Supply Monthly statistics showed that propane inventories in primary storage fell to a seasonal low of 27 million bbl. EIA inventory data report the combined volumes of both purity propane and refinery-grade propylene.

Propylene volumes contained in the reported inventory figure for the end of March totaled 2.7 million bbl. When propylene inventory is excluded, the true volume of propane in primary storage totaled only 24.3 million bbl.

On a net-adjusted basis, total US propane inventory at the end of March 2007 was 2.8 million bbl lower than year-earlier volumes. During second and third quarters 2007, accumulation of inventory in primary storage in the US totaled only 34-36 million bbl, or about 8 million bbl less than the average for 2003-06.

Feedstock demand

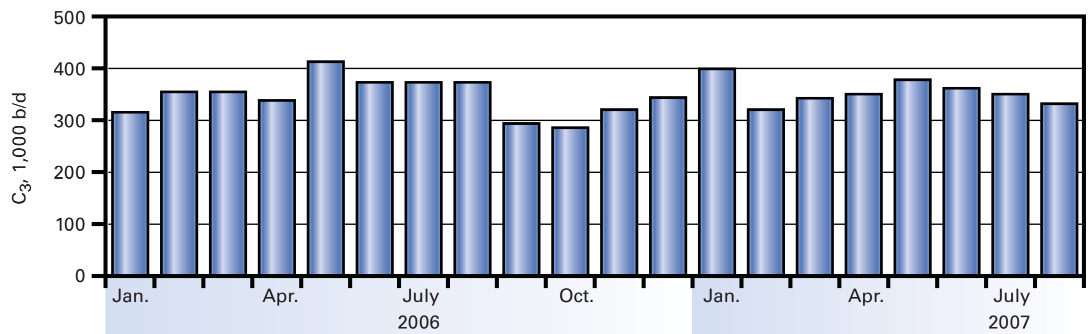
During first-quarter 2007, feedstock demand for propane rebounded to 357,000 b/d from 318,000 b/d in fourth-quarter 2006. Feedstock demand for propane continued to increase during second-quarter 2007 and averaged 366,000 b/d. Feedstock demand in second-quarter 2007 was only 10,000 b/d lower than in 2006 and did little to alleviate the growing inventory deficit.

As the inventory deficit widened during third-quarter 2007, propane prices in Mont Belvieu strengthened relative to other feedstocks, and feedstock demand declined to 352,000 b/d in July and 336,000 b/d in August. Feedstock demand in September hit an estimated 300,000-320,000 b/d and demand for third-quarter 2007 averaged 329,000-336,000 b/d.

In comparison, feedstock demand in third-quarter 2006 averaged 349,000 b/d, or 13,000-20,000 b/d more than in 2007. Again, as during second-quarter 2007, the year-to-year decline in feedstock demand was insignificant in comparison with the growing inventory deficit.

ETHYLENE FEEDSTOCK DEMAND FOR PROPANE

Fig. 1



Source: Petral Worldwide Inc.

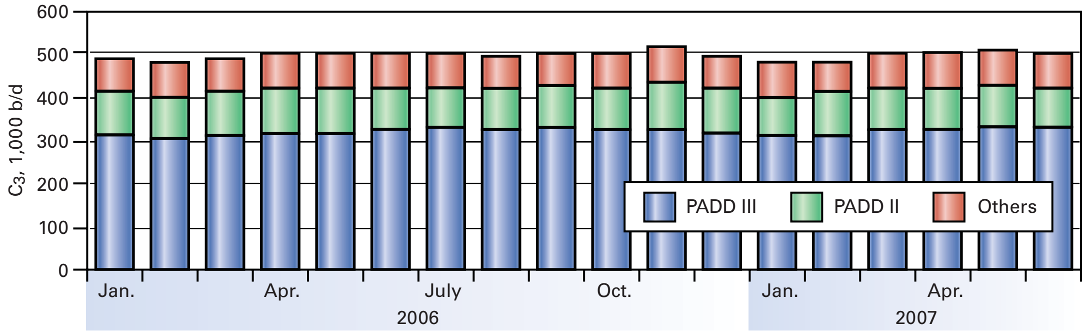
Ethylene plants operated at 91% of nameplate capacity during second-quarter 2007 and 93% of capacity during second-quarter 2007. Ethylene plants are forecast to operate at 90-92% of nameplate capacity during fourth-quarter 2007 and 92-93% during first-quarter 2008.

Total feedstock demand will likely average 1.70-1.725 million b/d during fourth-quarter 2007 and 1.75-1.78 million b/d during first-quarter 2008. Propane consumption in the ethylene feedstock market, however, will decline sharply in fourth-quarter 2007 and average 265,000-275,000 b/d, or about 50,000 b/d less than in 2006.

In first-quarter 2008, feedstock demand will average 280,000-310,000 b/d, or 55,000-60,000 b/d less than year-earlier volumes. The year-to-year decline in feedstock demand during fourth-quarter 2007 and first-quarter 2008 will offset the inventory deficit of 10 million bbl but only over the course of the winter heating season 2007-08. Fig. 1 shows historic trends in ethylene feedstock demand.

US GAS PLANT PROPANE PRODUCTION

Fig. 2



Source: US Energy Information Administration

> Propane feedstock demand has been one of the most important balancing elements of the overall propane market in North America. When colder weather has pushed sales and consumption in the retail markets steadily higher during November through February, ethylene producers in the Gulf Coast have used their substantial feedstock flexibility to reduce their consumption of propane.
>
> This predictable shift in feedstock demand for propane has offset some or all of the impact of a colder than normal winter, loss of production, or low inventory levels. Historically, most of the seasonal decline in ethylene feedstock demand has occurred during the fourth quarter.

Retail demand

Consistent with the seasonal in heating degree-days, retail demand fell to its seasonal low during second and third quarters 2007. April-May 2007, however, was about 20% cooler than April-May 2006 for the New England-Mid-Atlantic and upper Midwest regions.

Based on cooler weather during the transition to summer, we estimate that total retail propane sales averaged 425,000 b/d in second-quarter 2007, or about 60,000 b/d higher than in 2006. The year-to-year increase in retail sales equaled 5.5 million bbl and clearly affected the accumulation of inventory in primary storage during second-quarter 2007.

In third-quarter 2007, we estimate that retail propane sales averaged 200-210,000b/d vs. 195,000-205,000 b/d in third-quarter 2006. Retail sales were essentially equal to the average for 2001-06.

During a truly cold winter, retail propane sales will be significantly higher than during winter 2006-07. The record high for retail propane sales occurred during winter 2000-01 and totaled an estimated 210 million bbl. Propane supply-demand forecasts for winter 2007-08, however, are based on total retail sales of 180-190 million bbl. In comparison, retail sales totaled 171 million bbl during winters 2006-07 and 2005-06.

Retail propane markets in the US and Canada will face significant difficulties in meeting demand during a truly cold winter. Inventories in primary storage will almost certainly be fully depleted before the end of February 2008 in a winter with only an average number of heating degree-days.

Propane supply

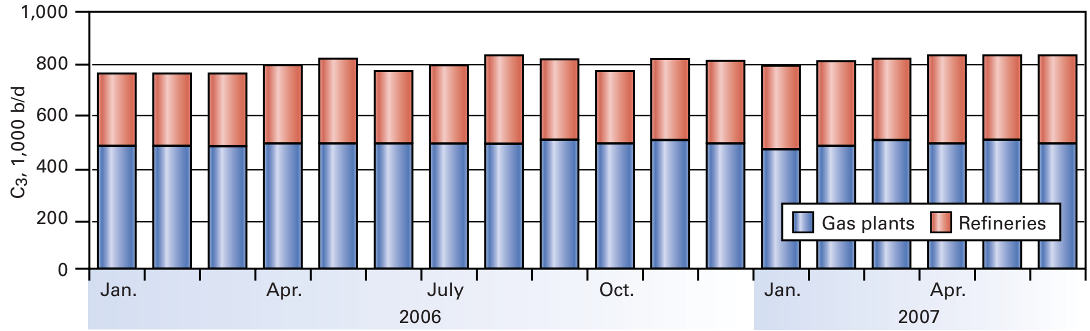
Gas processors continued to experience very strong profit margins in all US producing regions during second and third quarters 2007. Furthermore, propane prices were consistently 40-60¢/gal higher than their btu-equivalent based on spot natural gas prices in the Houston Ship Channel market—indicating that refineries had no economic incentive to use propane instead of natural gas in their fuel systems.

Strong profitability for all gas processing plants and the economic incentives for refineries lead to the conclusion that US propane production was at full recovery levels for both gas plants and refineries. Data published by EIA show total production from gas plants and net propane production from refineries averaged 841,000 b/d, or 39,000 b/d higher than year-earlier volumes.

> Propane's use as a space-heating fuel in residential-commercial reaches its seasonal peak each year during the fourth and first quarters. Residential-commercial propane demand begins to increase during October and usually reaches peak demand during December-January.

TOTAL US PROPANE PRODUCTION

Fig. 3



Source: US Energy Information Administration

Gas plants

EIA statistics indicate that gas plants' propane production averaged 503,000 b/d for second-quarter 2007 and was an estimated 505,000-515,000 b/d during third-quarter 2007. We expect gas plant production to average 490,000-500,000 b/d in fourth-quarter 2007 but to increase to 525,000-535,000 b/d in first-quarter 2008.

Fig. 2 presents trends in propane production from gas plants.

Refineries

In second-quarter 2007, propane production from refineries (net of propylene for propylene chemicals markets) averaged 338,000 b/d—an increase of 13,000 b/d from net refinery supply in first-quarter 2007 and 37,000 b/d higher than year-earlier volumes, according to EIA statistics.

We estimate that propane supply from refineries averaged 335,000-345,000 b/d in third-quarter 2007, and we expect net refinery production to average 320,000-330,000 b/d in fourth-quarter 2007. The projected decline in production in the fourth quarter is consistent with general seasonal trends and the seasonal decline in refinery operating rates.

Fig. 3 presents trends in total propane production (gas plants and refineries).

Imports

Based on data from the US Census Bureau's Foreign Trade Division, propane imports from Canada declined in second-quarter 2007, consistent with normal seasonal patterns. Imports from Canada averaged only 75,000 b/d in second-quarter 2007, however, or 19,000 b/d less than year-earlier volumes and 25,000 b/d below the average for 2000-05. We estimate that propane imports from Canada increased to 90,000-100,000 b/d in third-quarter 2007 and were 5,000-15,000 b/d below the average for 2000-05.

We have to ask why propane imports from Canada were consistently below average during second and third quarters 2007.

First, inventories of purity propane in underground storage fell to less than 2 million bbl by Mar. 1, 2007, and remained less than 2 million bbl until after Apr. 1. At the beginning of the inventory accumulation season, propane in underground storage in Canada was 1 million bbl less than the 5-year average and 1.3 million bbl less than year-earlier levels.

This inventory deficit represents 10-15% of Canada's peak inventory levels for 2001-05. Thus, Canadian producers tried to rebuild inventories by limiting exports to US markets during second and third quarters 2007. By Sept. 1, Canadian producers had increased inventories of purity propane to 9.4 million bbl, or about 900,000 bbl less than in 2006 and less than 600,000 bbl less than the 5-year average.

Consistent with seasonal supply trends, international imports increased in second-quarter 2007, but waterborne imports averaged only 78,000 b/d, as reported by the Foreign Trade Division. International imports were 32,000 b/d less than year-earlier volumes but slightly higher than the average for 2002-06.

We estimate that international propane imports averaged only 60,000-70,000 b/d during third-quarter 2007, or 88,000 b/d less than in 2006 and 45,000 b/d less than the average for 2002-06. The year-to-year decline in waterborne imports during second and third quarters totaled 11 million bbl.

> Consistent with the seasonal increase in retail propane sales, propane imports from Canada typically decline to seasonally low volumes of 100,000-110,000 b/d during second and third quarters. Propane imports from other international sources (outside North America), however, usually increase to a seasonal peak of 100,000-150,000 b/d during third quarter.

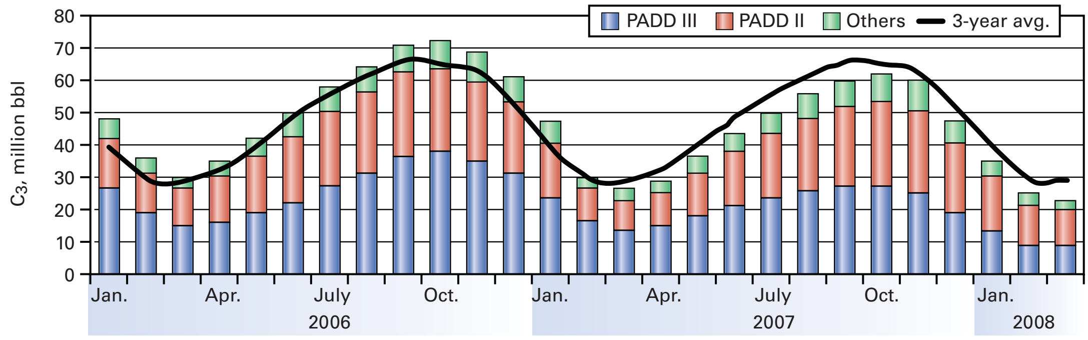
Overall inventory trends

Mar. 31 normally marks the end of the inventory liquidation season for the US. Occasionally, propane inventories continue to decline during April if temperatures are below average.

According to EIA weekly statistics, propane inventories fell to a seasonal low at the end of March 2007 and began to increase during the first week of April. EIA monthly statistics indicate that total inventories (including propylene for nonfuel uses) totaled 27 million bbl on Apr. 1.

US PROPANE INVENTORY

Fig. 4



Historical data source: US Energy Information Administration

During 2003-06, the seasonal accumulation of propane in primary storage ranged consistently 40-45 million bbl. In 2002, however, the seasonal inventory build totaled only 31.7 million bbl. For 2007, based on EIA's monthly statistics through July and weekly statistics for August and September, the seasonal inventory build totaled 32.5 million bbl and inventories totaled 59-60 million bbl on Oct. 1, 2007. Based on historic trends during October, inventories reached a peak of 61-62 million bbl in late October.

Including Canadian inventories in underground storage, propane markets will have access to 74 million bbl of supply in primary storage during the winter heating season. This volume was 12 million bbl less than in 2006.

At the end of the 2006-07 winter heating season, purity propane inventories in underground storage in Canada fell to a low of 1.9 million bbl on Mar. 1, 2007. At this level, purity propane inventories were 1.5 million bbl below the 5-year average and 2.5 million bbl lower than in 2006.

Based on statistics from Canada's National Energy Board, Canadian companies added 7.5 million bbl of propane Mar. 1 through Sept. 1, 2007. The seasonal build in Canadian storage erased nearly all the inventory deficit on Mar. 1, 2007.

Fig. 4 illustrates trends in US propane inventory.

During 2002-06, total withdrawals of propane from primary storage totaled 39-49 million bbl. For the 2007-08 winter heating season, withdrawals of more than 40 million bbl will pull US inventories below their historic low of 21.6 million bbl (March 1993). When accounting for pipeline fills, brine availability, and other distribution system constraints, the industry views 20 million bbl to be the practical minimum.

In an average winter, retail propane demand will be 5-10 million bbl higher than is forecast for winter 2007-08. With inventories likely to reach a seasonal peak of no more than 62 million bbl, the market has the potential to pull inventories to new record lows by February 2008 and may test the ability of storage operators to withdraw product from salt cavern storage. Furthermore, markets will also require feedstock demand for propane to remain below average throughout the winter heating season.

Regional inventory trends

On Apr. 1, 2007, propane inventory in primary storage in US Petroleum Administration for Defense District (PADD) II fell to a low of 8.6 million bbl, or 2.6 million bbl less than year earlier levels but only 0.3 million bbl less than the average for 2001-05.

During second-quarter 2007, inventory in primary storage in PADD II increased by 8.0 million bbl and totaled 16.6 million bbl on July 1. At this level, inventories were 4.1 million bbl less than in 2006 but only 0.8 million bbl less than the 2001-05 average.

During third-quarter 2007, inventories increased by an additional 8 million bbl and totaled 24-25 million bbl on Oct. 1. The inventory build during third-quarter 2007 was above average and reduced the deficit vs. 2006 to about 1.8 million bbl. Furthermore, inventories on Oct. 1 were also about 0.5 million bbl higher than the average for 2001-05.

According to EIA monthly statistics, propane inventory in primary storage in PADD III totaled 14.4 million bbl on Apr. 1, 2007, and were 1.2 million bbl below year-earlier levels but were only 0.7 million bbl below the average for 2001-05. During second-quarter 2007, however, inventory in primary storage in PADD III increased by only 7.4 million bbl vs. or 5.5 million bbl, less than the 2001-05 average. The slump in waterborne imports during second-quarter 2007 was a primary reason for the abnormally low build.

Furthermore, waterborne imports during third-quarter 2007 remained lower than in 2006 and the inventory build in PADD III during third-quarter 2007 totaled only 5.5 million bbl, or 2.1 million bbl less than average, based on EIA's weekly statistical report. As a result, on Oct. 1, inventory in PADD III totaled 27-28 million bbl and was 9.1 million bbl less than the year-earlier level and 7.8 million bbl less than the 2001-05 average. The inventory deficit of 9.1 million bbl in PADD III was primarily due to the year-to-year decline of 11 million bbl in waterborne imports.

Pricing, economics

During second-quarter 2007, propane prices in Mont Belvieu increased to an average of 113.9¢/gal in June

from 110.9¢/gal in April. Despite the modest increase spot prices, propane's ratio vs. West Texas Intermediate declined to 70.9% in June 2007 compared with 72.9% in April 2007. These comparisons indicate that spot prices in Mont Belvieu almost kept pace with the $3.61/bbl increase in spot WTI prices during second quarter.

With the onset of the hurricane season, WTI prices jumped sharply and averaged $74.10/bbl in July, or $6.65/bbl higher than the average in June. Propane prices increased in July but did not keep pace with the strong rally in WTI prices, and the ratio weakened to 67.5%. July marked the low point for the propane/WTI ratio.

> In most market situations, trends in crude oil prices and ethylene feedstock-parity values are the dominant influences on propane prices. The spring and summer of 2007 were not exceptional until September 2007.

Spot propane prices in Mont Belvieu averaged 121.7¢/gal in August and 128.4¢/gal in September. Propane's ratio vs. WTI also increased to 68.9% in August but slipped slight in September and averaged 68.1%. Trading activity in Mont Belvieu during second and third quarters 2007 ignored the mounting evidence that propane supply for winter heating would be significantly lower than during 2004-06.

Parity values

During second-quarter 2007, spot prices in Mont Belvieu averaged 113.2¢/gal and propane's feedstock parity value averaged only 112.8¢/gal. By this measure, propane prices were neutral relative to ethane and natural gasoline during second-quarter 2007. During third-quarter 2007, however, spot prices in Mont Belvieu averaged 122.3¢/gal but feedstock parity values averaged only 117.8¢/gal.

Based on this comparison, propane prices were relatively stronger during third-quarter 2007. The shift in price/value relationships during third-quarter 2007 was consistent with the emerging view of tight supplies for 2007-08 winter heating.

2007-08 winter prices

Many people in the petroleum products and petrochemicals industries expect crude oil prices to remain greater than $80/bbl or to increase further during the 2007-08 winter heating season.

During 2001-06, propane's price ratio vs. WTI averaged 70-75% in fourth quarter. The tight supply situation and low inventory level in PADD III will support stronger propane prices relative to other ethylene feedstocks. Based on an expected propane/WTI price ratio of 75% and WTI prices at $80/bbl, spot prices in Mont Belvieu are likely to be 135-145¢/gal during fourth-quarter 2007.

In 2006, WTI prices in fourth quarter fell by $10/bbl vs. the average for

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	July 2006	June 2007	July 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,751.1	1,846.5	1,846.5
Electrical machinery	189.5	394.7	516.9	513.6	520.2	523.2	517.7	517.3
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	961.9	973.9	974.5
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,173.4	1,267.5	1,272.4
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,117.8	1,196.1	1,197.1
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,309.4	1,507.0	1,368.2
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,480.7	2,593.6	2,596.4
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	2,012.2	2,159.0	2,105.1

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	July 2006	June 2007	July 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,579.7	1,611.4	1,537.9
Labor cost	93.9	200.5	191.8	201.9	204.2	199.0	216.8	207.1
Wages	123.9	439.9	984.0	1,007.4	1,015.4	999.0	1,027.5	1,025.8
Productivity	131.8	226.3	513.3	501.1	497.5	502.1	474.0	495.2
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	745.2	796.7	776.8
Chemical costs	96.7	229.2	268.2	310.5	365.4	376.0	390.2	396.2
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	579.5	613.1	594.6
*Process units**	103.6	457.5	638.1	787.2	870.7	873.4	907.9	872.3

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

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

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

In view of the ethylene industry's significant capability to adjust its consumption of propane within 1-2 months, propane prices vs. alternative ethylene feedstock values are a better measure of the relative strength or weakness in spot prices in Mont Belvieu.

third-quarter 2006. For fourth-quarter 2007 and first-quarter 2008, crude oil inventories will be adequate, gasoline prices are likely to fall to typical seasonal levels vs. WTI.

Hence, WTI prices may fall by $10-15/bbl during fourth-quarter 2007 and may average $65/bbl in fourth-quarter 2007 and $60-65/bbl in first-quarter 2008. On this basis, spot propane prices in Mont Belvieu will decline to 105-115¢/gal for fourth-quarter 2007 and first-quarter 2008. ✦

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CBUs eliminate BTX-induced catalyst deactivation

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Gas Processing

BTX: PROBLEM AND SOLUTION—Conclusion

The first part of this two-part series (OGJ, Oct. 22, 2007, p. 60) describes how Saudi Aramco faced chronic Claus catalyst deactivation for years as a result of benzene, toluene, and xylene (BTX) in lean acid gas feed to several of its sulfur-recovery units (SRUs). Construction of seven BTX removal units using regenerable activated carbon beds was completed in December 2005; commissioning took place in spring 2006.

This concluding article will discuss design issues, operating experience for the units, and their performance and effect on the downstream Claus catalyst.

Fig. 1 shows one of the carbon-bed units.

In brief, catalyst deactivation has been virtually eliminated. This has set the foundation to allow us to revamp the units to achieve higher recovery, which would not have been possible until catalyst deactivation had been resolved.

Design issues

A process selection study carried out in 2000 identified carbon beds as the most economical process solution. That evaluation was based on a five-vertical-vessel design.

Number of carbon beds

From the outset the question of disturbance to the SRU's reaction furnace and air-demand analyzer during vessel switchover was a concern. For minimizing this impact, the greater the number of vessels the better because adding vessels reduces the proportion of the total feed being diverted.

Of course this is offset by matters of practicality. As the number of vessels increases, so does the plot area, complexity, and cost, driven to a great extent because of increasing switching valve count.

At the detailed design phase of the project, a design with three horizontal vessels in lieu of the five-bed configuration was proposed. In this arrangement, two beds would be online and one regenerating or in standby. Initially there was a concern that half of the flow being diverted to the regenerated bed during switchover might cause disturbances to the SRU. At the end of the regeneration step, the carbon bed retains a lot of water.

When the vessel is brought online, the acid gas has a capacity to absorb water. Being at 50% relative humidity, however, acid gas leaves the bed saturated. Over time the bed is striped of water and is completely dried long before the end of the adsorption cycle. This water is carried directly the SRU.

The three-vessel proposal had significantly more carbon than the five-bed design. This resulted in the number of cycles per day being less than half than for the five-vessel case. The water spikes

This is one of the seven carbon-bed BTX-removal units (Fig. 1).

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would be greater in absolute terms because half the flow is diverted to a freshly regenerated bed with a three-vessel configuration. On a daily basis, though, the total amount of water sent to the SRU by the carbon-bed unit (CBU) is slightly less with the three-bed design.

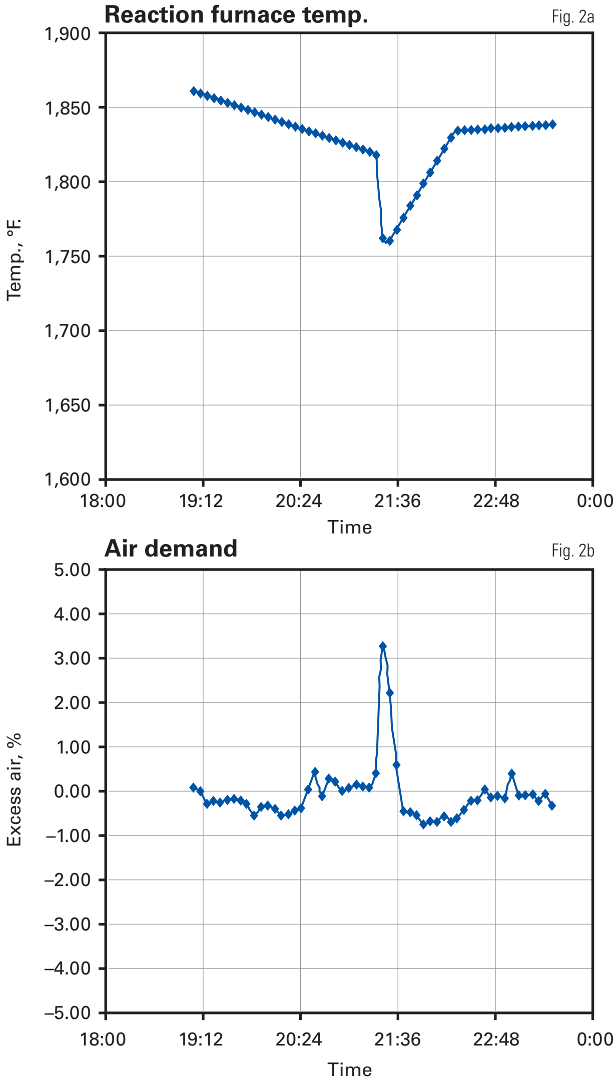
It remained to be determined if the three-bed configuration would cause unacceptable disturbances during switchover. A simulation of the reaction furnace's flame temperature indicated a 40° to 60° F. temperature drop assuming half the acid-gas feed was saturated with water at the bed conditions after regeneration. We thought this to be acceptable and proceeded with the three-bed design that had been recommended.

The recovery loss resulting from the addition of water was calculated to be 0.05%. (By the LeChatelier principle, water shifts the Claus reaction equilibrium unfavorably.) There is also a small amount of acid gas that is lost each time a vessel is regenerated.

As mentioned in the process description in Part 1, the acid gas in the vessel at switchover is displaced through the regeneration condenser to the pressure control drum. These noncondensables are sent to the flare system. With the net vessel volume and the number of cycles per day, the recovery loss from this amount of flared acid gas was calculated at 0.028%.

EFFECT OF SWITCHING BED TO ACID GAS

Fig. 2



Design parameters

Designing a CBU requires several parameters be known. The first, capacity, defines how much heavy hydrocarbon can be retained per mass unit of carbon. Beyond that amount the mass-transfer zone moves up the bed. The capacity of typical industrial carbons expressed as a percentage is a single digit number.

The good news is that it is a function of concentration in the stream to be treated. This gives the process an inherent flexibility. If one designs for a given level of aromatics using the manufacture's recommended capacity and the feed later has more contaminants, the capacity will also be greater at the new feed conditions. The capacity may not increase in direct proportion to the aromatics composition, but there is a mitigating effect.

Sizing of the vessels is done to achieve a target superficial velocity through the bed when in adsorption mode. Design guidelines have been reported in an earlier paper on this subject (OGJ, June 24, 1996, p. 31). The superficial velocity is calculated at flowing conditions as if there were no carbon loaded in the vessel.

Pressure drop through the bed is an important consideration because usually there is a limit on how much can be tolerated before the SRU capacity is reduced. The biggest sources of the pressure drop are the acid gas preheater and the beds themselves. The CBUs were designed for a total pressure drop of less than 2 psi.

The bed's pressure drop is calculated from Ergun equation parameters provided by the carbon supplier. A design is developed by varying superficial velocity and bed height until a reasonable configuration is reached.

Removal efficiency refers to the percentage of each contaminant adsorbed from the treated stream. When the bed is dry the removal efficiency for BTX is 95-100%. Process conditions are maintained to enhance efficiency: lowest possible adsorption temperature balanced against relative humidity.

Bed regeneration is accomplished with low-pressure steam. For design purposes a fixed amount of steam per unit of carbon is used (OGJ, June 24, 1996, p. 31). There is a trade off in deciding how fast the regeneration is performed.

If the set quantity of steam is passed through the bed in a short interval, the bed can be brought online sooner, which means less total carbon need be installed because it is in service proportionately longer compared to the regeneration step. Conversely, this

would require the downstream regeneration steam condenser and three-phase separator to be larger to accommodate the higher rate.

Vessel orientation

Vessel orientation—horizontal vs. vertical—is not a process issue: Either can be used effectively. It is a matter of providing an enclosure for the carbon bed whose size has already been defined from the process parameters discussed above. What determines the choice of orientation is the effective use of steel to hold the bed.

One can calculate and compare the "overhead volume"—the ratio of vessel volume not containing carbon to the total volume—between vertical and horizontal configurations. For given bed dimensions this will be different.

Related to this is the practical consideration of providing enough space for man ways and vessel entry. On a horizontal vessel, beyond a certain size, the curvature effects become negligible. In this case the vessel does not have to be enlarged just for entry purposes. On a vertical vessel of any size, a minimum free board must be allowed for above and below the bed.

Eliminating drying step

As noted, the adsorption efficiency is improved when the bed is dry. For benzene, this effect is more pronounced than toluene and xylene. Our pilot plant tests showed that we could still achieve substantially complete removal of the toluene and xylene without cooling and drying the bed after regeneration before bringing it back online. By comparison, we found that only about 80% overall benzene removal could be accomplished if the bed was left wet.

Uncertainty about how residual benzene slippage would affect Claus catalyst was the major issue in the early stages of the process selection study. Our contract research at Alberta Sulfur Research Ltd. determined the effect of benzene on Claus catalyst to be negligible.[1 2] As a result we did not design for bed cooling and drying at the end of the regeneration step.

The carbon bed designers advised that we should expect a brief spike of BTX in the initial 3-5 min of the adsorption cycle because of the wet bed. For reasons completely analogous to the water spike discussion above, the three-bed design proved superior to the five-bed configuration. Although the BTX spike is greater than it would have been with a five-bed design, the total moles of aromatic slippage is less with the three-bed design because it cycles less frequently.

Eliminating the cooling and drying step from the regeneration sequence yielded substantial cost savings to the project. It was possible to reduce the scope significantly from what it would have been otherwise. There was no need for a drying gas cooler, separator, and recompressor. In addition, the amount of carbon installed was reduced because the regeneration step was shorter.

Materials

All of the vessels within the CBU are made of 316 L stainless steel. The initial specification called for carbon steel with internal stainless cladding, however. As detailed design and procurement proceeded, we determined that using a single material for vessel construction would in fact be simpler overall. Delivery times were shorter, and the cost difference was not a determining factor.

There was one concern with stainless steel construction that required mitigation: the bane of stainless steel—chlorides. After considerable deliberation we concluded that external coating of the vessels would protect against environmental chlorides. This was applied, and the vessels were insulated.

Water samples from the upstream knockout drum revealed chloride concentrations between 5 and 20 ppm. We wrestled with the question of to what extent, if any, chlorides in the water from the knockout drum would be able to migrate past the feed preheater and on to the carbon beds. To do this, free water would have to be entrained from the knockout drum. The Cl^- ion cannot exist as a free atom; it must be in aqueous solution to exist as a chloride. In the preheater, because acid gas is heated to reduce the relative humidity to about 50%, there is no free water.

To guard against the remote possibility that free water containing chlorides could migrate to the carbon beds and to promote effective steam condensate drainage, we instructed the fabricator to flush-grind weld seams and the outlet nozzle at the center of the vessel in the 6 o'clock position. This is the nozzle from which the initial condensed steam is removed.

Our metallurgical engineer noted that, provided there was no build up of stagnant water within the vessel, there would be far less opportunity for chloride attack. Furthermore, he advised that stainless steel is far less susceptible to chloride attack if there is no oxygen present. For process reasons the carbon beds are always kept completely free of air during operation; this gave us added confidence there would not be a problem.

Commissioning

During initial commissioning, reaction-furnace flame instability was a problem during switchover of a regenerated carbon bed. Since then, however, very significant progress has been made to reduce the magnitude of disturbances to the SRU during switchover. We are continuing to refine the sequence logic further to minimize disturbances to the SRU from operation of the carbon beds.

CBU performance

We begin with a discussion of the disturbance to the reaction furnace and air-demand analyzer caused by bringing a regenerated vessel online. The process data discussed reflect operation with the sequence logic we have developed.

Fig. 2 presents plots of reaction-furnace temperature and air-demand analyzer output vs. time for an SRU during

SRUs AT GAS PLANTS

Fig. 3

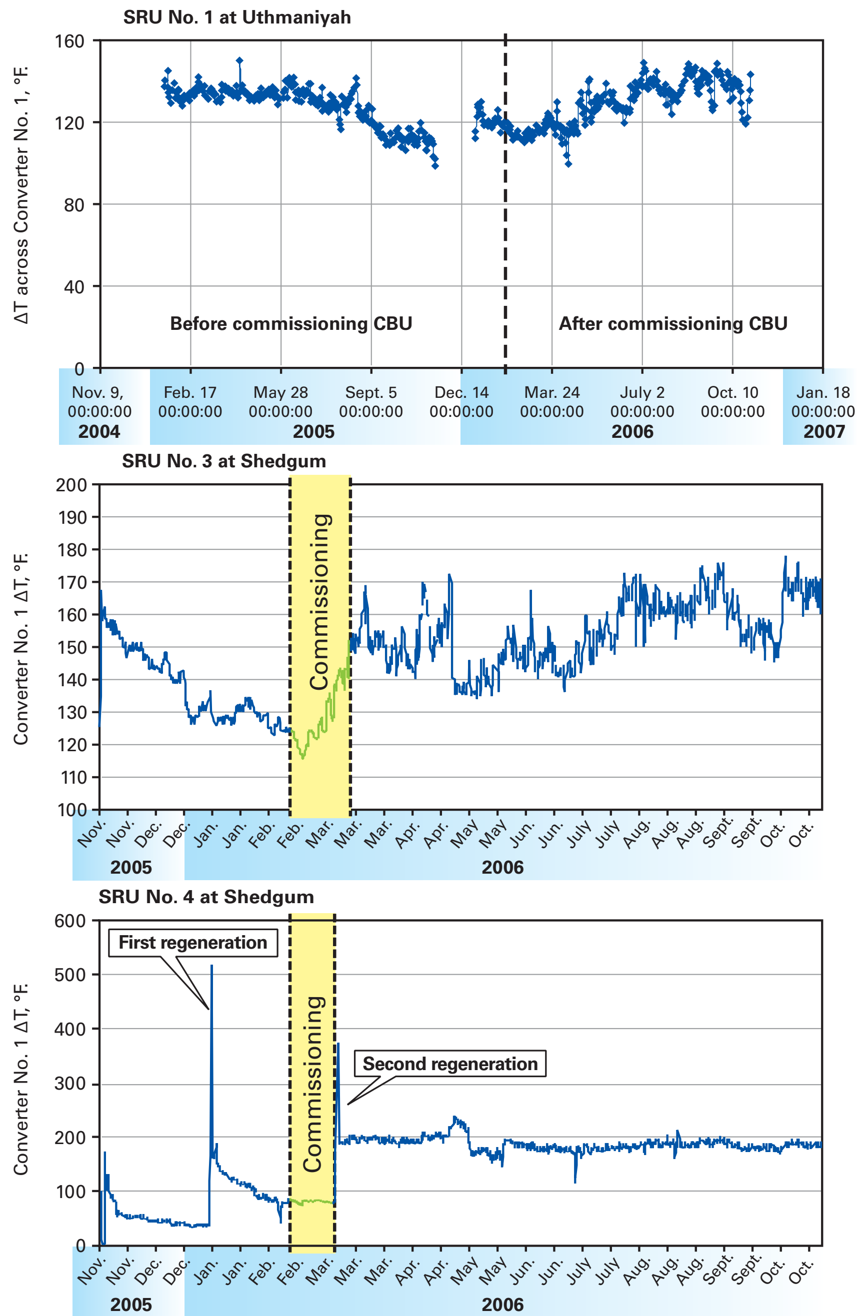


Fig. VIII-1 in H. Paskall's Capability of the Modified-Claus Process shows recovery loss due to off-ratio operation in terms of percent excess or deficient air.[3] Taking as a basis 96% recovery for a very lean feed SRU with perfect control, the recovery drops by ⅓% for an excess air of 3.25%.

To be conservative we assume the time of decreased recovery due to off-ratio operation is 2 hr/day, which is definitely a worst-case assumption because it takes the peak off-ratio value over the entire period. Taking ⅓% recovery loss for 2 hr out of 24-hr results in a daily net recovery loss of (2/24) • ⅓% = 0.028%. Although this value is very small, we are working on eliminating these spikes in air demand altogether.

As far as CBU performance itself is concerned, the capacity and removal efficiency as defined earlier has generally met or exceeded expectations. A surprise has been the extent to which benzene removal has surpassed 80% even during the early part of the adsorption cycle despite the fact that the beds are not being dried and cooled as part of the regeneration step.

The adsorption time to breakthrough is greater than design, indicating that the capacity of the carbon used in design was conservative. (Breakthrough is defined as the mass-transfer zone reaching the top of the bed.) There have been some unexpected analytical results between the two gas plants that we are reviewing.

At this point we have not determined with certainty if there is a real process difference or an unresolved analytical issue. As one can appreciate when analyzing for aromatic components in the single-digit ppm range, a minor change in reported outlet composition will have a significant impact on calculated removal efficiency.

Deactivation of Claus catalyst due to BTX poisoning has been eliminated or reduced to such a small value that it has not been possible to measure over 20 months. Graphs in Fig. 3 show the impact. These graphs show first converter temperature profile vs. time for selected

switchover. The reaction furnace's temperature drops by about 60° F., in line with simulation results discussed earlier. Visual inspection of furnace flame when vessels are brought online shows no noticeable change in flame pattern.

Switching vessels causes a brief disruption to the tail gas $H_2S:SO_2$ ratio (Fig. 2b). The period of off-ratio operation is short-lived and corrected in less than half an hour. Because the vessels are switched fewer than four times per day, recovery loss due to the transitory period of off-ratio tail gas is insignificant.

To obtain a qualitative estimate, consider Fig. 2b which shows the air demand peaking at 3.25% excess air.

SRUs at Uthmaniyah and Shedgum gas plants that had a CBU installed to treat their feeds. The performance of the other units is similar and was reported in the original Laurance Reid Gas Conditioning Conference paper.

Feed variations

A few words of background are necessary to interpret these results. At Uthmaniyah and Shedgum, the trains receive acid-gas from headers that are fed from gas-treating units that process both associated and Khuff gas. The mix between the two varies from day to day; as a result acid-gas quality is not constant.

Variations in acid-gas composition will change the first converter ΔT for a given reaction furnace bypass amount and catalyst activity. That is why there is considerable variation in the converter ΔT shown in the figures. Still, one can observe a clear downward trend for converter ΔT before installation of the carbon beds and the stable temperature profile afterwards.

To illustrate the point, Fig. 3c for Train 4 at Shedgum is discussed in detail.

The temperature scale for this figure, greater than in the other figures, suppresses the day-to-day fluctuations caused by changes in sour-gas feed mix and allows the general trend to be seen more clearly. As well, this train underwent two catalyst regenerations, which shows how BTX was devastating the catalyst before installation of the CBU.

This is the train that processes a mix of acid gases from both associated and high-pressure Khuff gas treating and as a result has more BTX in its feed. From November 2005 to January 2006, the ΔT had dropped to about 35° F., indicating the first bed was only achieving 20-30% approach to equilibrium. A catalyst regeneration completed in early January restored a substantial degree of activity, bringing the ΔT up to around 165° F.

Immediately after regeneration, the activity started to drop dramatically again, so that by the middle of February the ΔT was only 80° F. At that time the CBU for Train 4 was commissioned and another catalyst regeneration performed. After that, the converter's ΔT is seen to be essentially constant, only changing in response to feed composition variations.

Although Fig. 3 only reports first converter ΔT up until November 2006, the carbon beds continue to demonstrate excellent results. There has been no apparent decrease in activity in the first converters through to early August 2007.

The elimination of BTX-caused deactivation has already had tangible and important benefits. Whereas it had been the practice to replace large amounts of Claus catalyst every 2 years to maintain recovery, it has been determined that catalyst changes can be deferred, resulting in savings of hundreds of thousands of dollars because of the size and number of SRUs involved.

Perhaps even more significant is that our planned conversion of the SRUs at Shedgum and Uthmaniyah to the SuperClaus process can go ahead as planned. Without our first addressing the chronic deactivation that had been experienced for the last 25 years, SuperClaus would not have been a viable process retrofit.

First maintenance; inspection shutdown

As discussed earlier, there was a concern regarding chlorides and possible corrosion in stainless-steel vessels. We completed almost 1 year of operation on one of the trains and in November 2006, the CBU and SRU were shut down for routine maintenance. This afforded us the opportunity to open and inspect the carbon-bed vessels to look for signs of corrosion.

The bottom of the vessels showed signs of where the regeneration steam condensate had flowed to the center outlet nozzle. Whereas the vessel walls above and below the carbon bed were shinny, there was some discoloration at the ends of the vessel at the 6 o'clock position.

As well, the vessel wall behind the carbon bed was very mildly discolored. Red dye penetrant testing, however, showed no cracks or indication of incipient metal damage such as pitting. Our plan is to follow up with another inspection in a year's time to monitor the condition of the vessels and ensure the results recently seen are maintained.

Installation of carbon beds to adsorb BTX from acid-gas feed to Saudi Aramco's lean feed SRUs has successfully eliminated BTX-induced Claus catalyst deactivation.

The operational performance of the CBUs has exceeded expectations in as much as the adsorption cycles are longer than anticipated in the design. This has led to a lower-than-expected production of regeneration steam condensate.

Acknowledgments

The authors thank Graham R. Lobley in Saudi Aramco's Consulting Services Department who advised the project on the metallurgical questions and Dean W. French in Gas Operations Continuing Excellence who advised on operational issues. ✦

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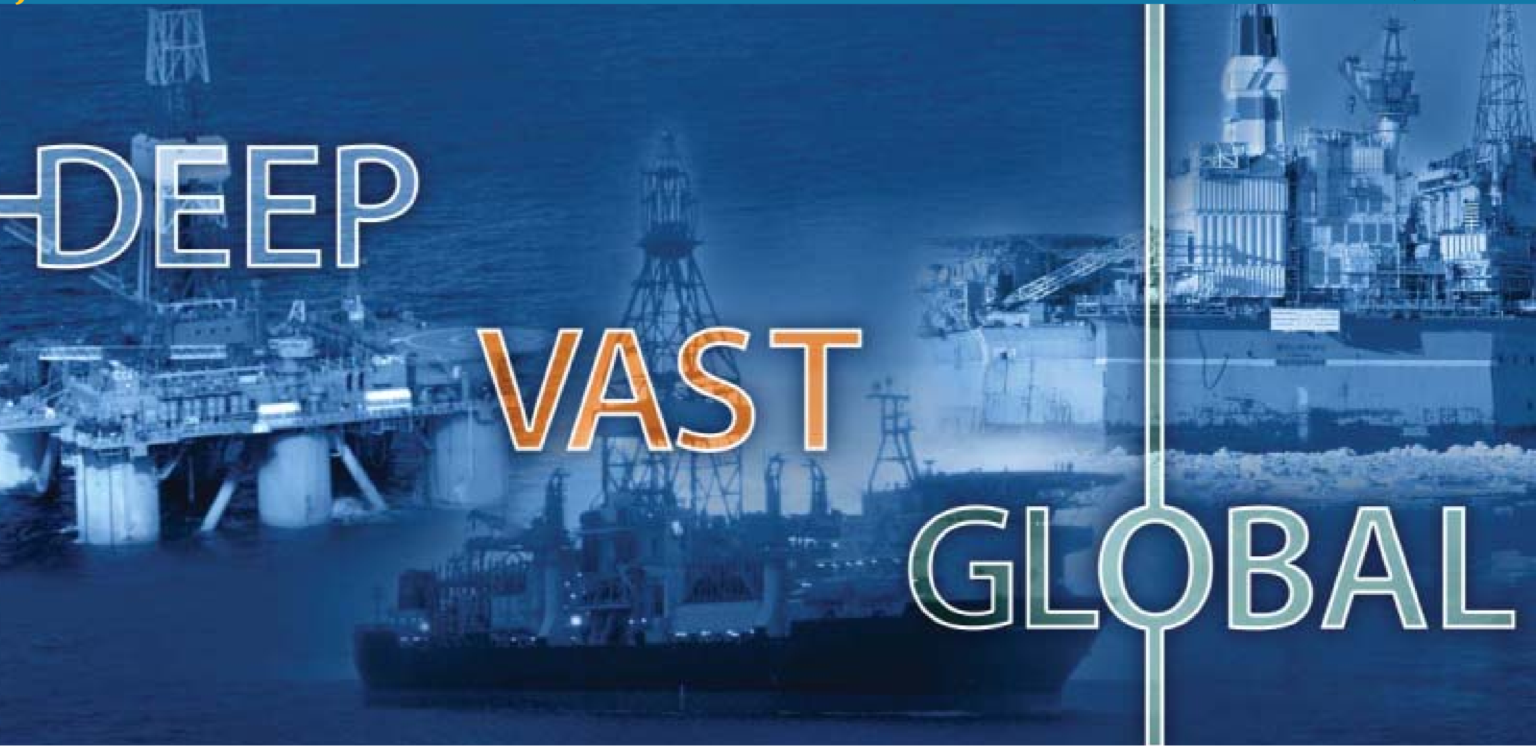
DEEP
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GLOBAL

PIPELINE INSPECTION—1

Uncertainty-based assessment substitutes for internal inspection

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Internal inspection of pipelines is not always economic, prompting development of methods for assessing a pipeline's current condition based on historic operating and process conditions. Modeling the corrosivity of the fluids over the life of the pipeline allows establishment of an assessment of the line's current condition. This in turn allows development of a risk-based approach to extending asset life.

The risk-based analysis uses uncertainty-based probability analysis to allow for gaps in data and uncertainty in process conditions. Changes in operating condition and process fluids over time will affect likely year-on-year degradation.

Based on presentation to the NACE Corrosion 2007 Conference, Nashville, Mar. 11-15, 2007.

This first part of two articles describes the parameters of the risk-based approach and presents the first of two case studies in which use of uncertainty modeling allows assessment of the pipeline's current condition. Life expectancy is presented as a probability profile, which can then assess the risk associated with changing future process parameters. This modeling approach also allows corrosion data to be transferred into financial data by assessing probability and risk.

The second, concluding, article will present the second case study.

Background

Ensuring pipeline integrity has become increasingly important to the oil and gas industry. An ageing pipeline infrastructure faces increased pressure from regulators and a zero-tolerance approach to hydrocarbon releases.

The opening of marginal fields requires existing pipelines to operate well beyond their original design life and in many cases with large changes in operating conditions. Development of new fields in remote environments is also leading to use of technically problematic designs. Embracing high-level integrity-assurance procedures even before front-end engineering and design is essential to maintaining an understanding of the likely level of pipeline degradation.

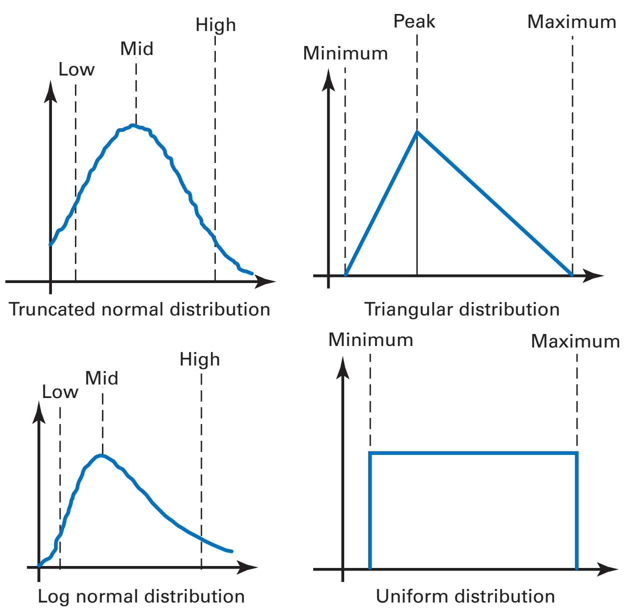
All such factors increase the uncertainty of predicting pipeline condition and future integrity.

Current condition

An in-line inspection using an intelligent pig measuring WT for the length of a pipeline would ideally determine

TYPICAL DATA DISTRIBUTIONS

Fig. 1

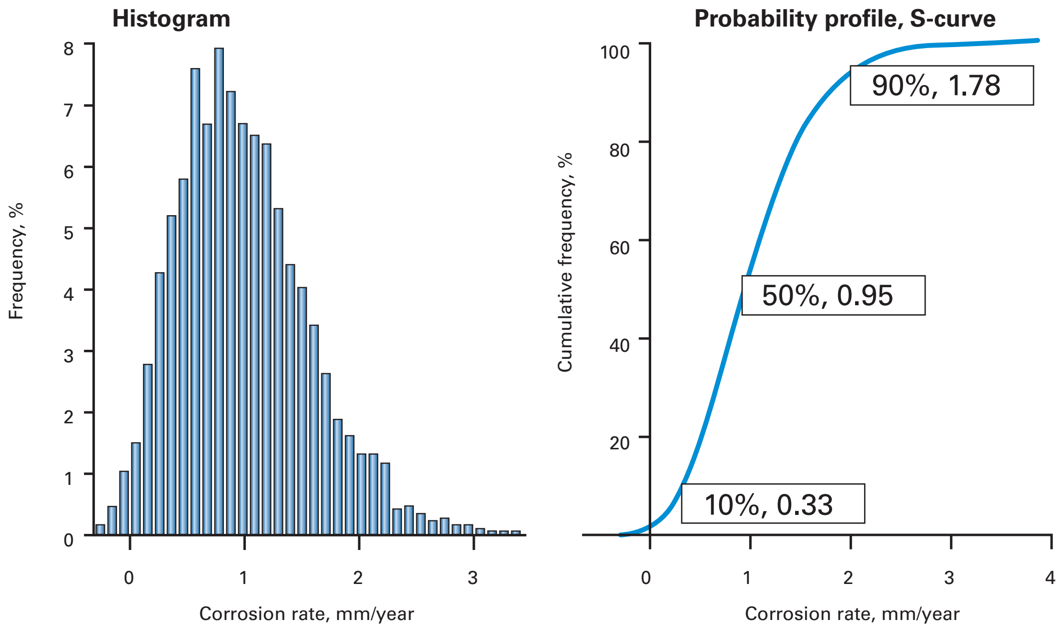


the line's current condition. But this is not always possible. Many older pipelines have varying internal diameters or sharp bends preventing use of ILI.

Inspecting from the outside surface of a pipeline at accessible locations using non-intrusive inspection techniques such as ultrasonic WT measurements will not give a comprehensive picture of any degradation at inaccessible locations on the pipeline. Uneven elevation can allow debris, water, etc. to collect at discrete points within the pipeline and initiate corrosion. Similarly, corrosion-monitoring data only assesses where probes or coupons lie.

Output types

Fig. 2



Combining an assessment of the historic operating parameters over the life of a pipeline and calculating a cumulative metal loss after commissioning, while also using uncertainty analysis to allow for unknown variations in operating parameters, can overcome some of these problems.

Assessment would typically only look at recent operating conditions and calculate typical metal loss based on these parameters. This article's methodology divides the operating life of the pipeline into discrete periods linked to changes in the parameters influencing the corrosion process. The assessment of historical data will not be fully accurate, requiring a statistical approach that creates a probability-based cumulative corrosion profile.

Incorporating uncertainties in operating data (e.g., temperature, pressure, CO_2, corrosion inhibitor availability, and efficiency) into traditionally conservative corrosion prediction tools allows a more accurate assessment of risk and better selection and targeting of control programs. A sensitivity analysis of the output then allows a clearer picture of required critical parameters. Reducing the level of uncertainty in these critical input parameters can reduce any uncertainty regarding the condition of the pipeline.

Future condition

This approach can predict the future condition of a pipeline under a variety of planned operating scenarios. Assessing the uncertainty and likely variation in operating and maintenance parameters or alternative future operating schemes can assist budgetary and operational decision-making. For example, assessing the effect on pipeline end-life of enhanced pigging operations, reduced chemical injection, or the introduction of a new fluid, allows characterization of the future risk of failure and identification of the benefits of different approaches.

This approach has assessed the current and future condition of several pipelines in the Middle East and the North Sea. This article discusses two case studies from this work.

- Case Study 1 uses uncertainty modeling to allow comparison of future maintenance activities in terms of extension of asset life; easily quantifying the cost of maintenance.
- Case Study 2—discussed in the concluding article of this series—uses the uncertainty approach to produce an annual assessment of pipeline integrity that then predicts the remaining life of an entire pipeline network, allowing development of an optimized corrosion control program and targeted inspection program.

Generic uncertainty

The approach taken distributes values to each uncertain variable contributing to the likelihood of failure: corrosion rate, temperature, WT, oil-water wetting factor, etc. The operator can compare results representing different operating scenarios (e.g., chemical treatment vs. replacement, pigging vs. not pigging) and more easily identify their cost benefits.

Without uncertainty modeling, a corrosion model will only reveal a single outcome, generally either the worst case or the average scenario. Statistical based uncertainty modeling uses both a corrosion-metal loss model and simulation to automatically analyze the effect of varying inputs on outputs of the modeled system.

The probability of failure of the pipeline on a year-by-year basis for those scenarios in which the consequences of failure remain the same can describe the effect on risk of failure.

A statistical distribution describes the uncertainties in the input data. Real operating data, collected from the field, for example pump uptime, chemical dosage rate, frequency of cleaning pig runs, pipeline pressure, etc., typically define the distribution. The range of defects measured during an intelligent pig inspection can assign current condition as a distribution.

This approach can also extend to a range of damage rates identified by subsequent inspections at the same locations, or use corrosion monitoring data when available. Laboratory test data can assign corrosion inhibitor efficiencies based on testing of specific inhibitors with specific fluids and internal surface conditions.

Where data gaps exist, for example in corrosion inhibitor dose rates, anecdotal, or tacit knowledge from the field can provide a credible range of values.

The conditions surrounding the particular variable, and therefore specific to the parameter in question, shape the distribution and the definition of the low, mid, and high values (or average and standard deviation of the values).

Typical distributions include:

• Truncated normal (used for general corrosion distribution in accordance with DNV G101[1]).

• Log normal (used for pitting corrosion defects in accordance with DNV G101[1]).

An analysis of actual operational data normally determines other distributions, examples include:

• Triangular (used for inhibitor effectiveness and availability; based on typical operational variations).

• Uniform (used for pressure; this is based on typical operating variations where a wide range of pressures with no discernable pattern occurs).

• Minimum extreme (used for temperature under rapid cooling pipeline conditions).

Wherever possible, distribution should be the best fit obtained from the actual operational data. In situations where the data are insufficient to allow analysis, or where operational experience is limited, it is recommended that a triangular distribution be used for all unknown parameters.

Fig. 1 shows some examples of these distributions.

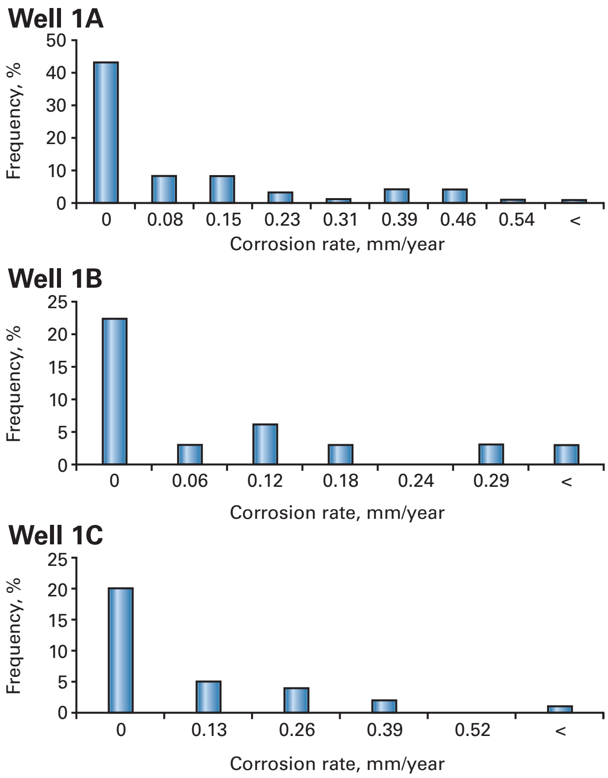
A Monte Carlo simulation can embed the distributions into a standard corrosion rate or metal-loss calculation. The simulation calculates multiple scenarios of a model by repeatedly sampling values from the probability distributions for the different uncertain variables. A single trial carries a randomly selected value from each of the defined ranges through the model to produce an output. Multiple passes are carried out (typically 1,000-10,000), defining a range of possible outcomes. Either a histogram or a probability profile (also known as a cumulative probability curve or S-curve) represent the results (Fig. 2).

A histogram displays all the outcomes along the X-axis and the probability (frequency) of occurrence along the Y-axis. It divides the X-axis into a suitable number of equal intervals, allowing the shape of the range of outcomes to be visualized and the symmetry and peaks in the distribution to be seen.

The S-curve shows the likelihood or probability of reaching certain values. The Y-axis displays the cumulative frequency as a function of the output values along the X-axis. A steep and narrow S-curve shows less uncertainty, while a wide and long S-curve shows

Extrapolated corrosion rate distributions

Fig. 3



Analysis parameters

Table 1

	Distribution type	Minimum value	Median value	Maximum value
General Corrosion rate, mm/yr	Truncated normal	0.15	0.35	0.55
Pitting Corrosion rate, mm/yr	Truncated normal	0.1	0.3	0.9
General corrosion inhibition efficiency	Triangular	70%	80%	90%
Corrosion inhibitor pitting efficiency	Triangular	10%	50%	90%
Corrosion inhibitor availability	Triangular	50%	70%	95%
Improved general corrosion inhibitor efficiency	Triangular	89%	90%	95%
Improved pitting corrosion inhibitor efficiency	Triangular	87%	90%	93%
Improved corrosion inhibitor availability	Triangular	94%	95%	98%

more uncertainty in the variables.

Case Study 1

Unexpected corrosion prompted an internal corrosion threat analysis on a pipeline carrying crude oil from an offshore platform to onshore processing for a client in the Middle East. The analysis assessed the effect of accelerating corrosion-mitigation measures.

The pipeline, commissioned in 1999, is operation-critical as it carries the operator's total production from a relatively small unmanned offshore production platform to onshore processing facilities. Design of the pipeline used the field's expected 20-year production life.

The pipeline operated without inhibition before commissioning of the chemical injection facilities. Injection of corrosion inhibitor began at a reduced rate as compared with original target dose rates due to problems with injection pump capacity and limited control on management of the inhibition processes. Inspection of the accessible offshore production manifold sections showed that corrosion was occurring in the manifold sections of three producing wells.

Modeling sought to:

- Determine whether any damage to date had a major effect on the 20-year design life of the main oil line.
- Carry out an assessment of the effect on the probability of failure of the pipeline of implementing an improved chemical injection program.
- Carry out an assessment of the effect on the probability of failure of the installation of pig traps now and in future to enable routine cleaning pigs to be run, removing debris from the pipeline and improving the effectiveness of chemical inhibition.

The operator wanted to assess the effect of deferring the costs of implementing the programs against the enhanced risk of failure.

Threat assessment

Review of operating conditions, fluid chemistry, inspection reports, and pulled tubing surveys confirmed the main corrosion threat to be pitting corrosion due to dissolved CO_2 and H_2S, leading to formation of iron sulfide films. Inhibitor dosage records revealed historical under-dosing of product against target concentrations, although there was good correlation with iron count data that the inhibitor was effective when dosages were achieved.

Inspection data taken from manifold pipework at the pipeline inlet generated a statistical distribution of likely corrosion rates. Fig. 3 shows examples of the range of calculated corrosion rates from inspection data.

Operating history

Analysis considered two distinct periods of historical operation:

- Period 1: From the time of commissioning (September 1999) to December 2001, during which time the line operated with no corrosion inhibition.
- Period 2: From December 2001 to January 2004, during which partial inhibition was in place.

Future scenarios

Analysis also evaluated four potential future operating scenarios:

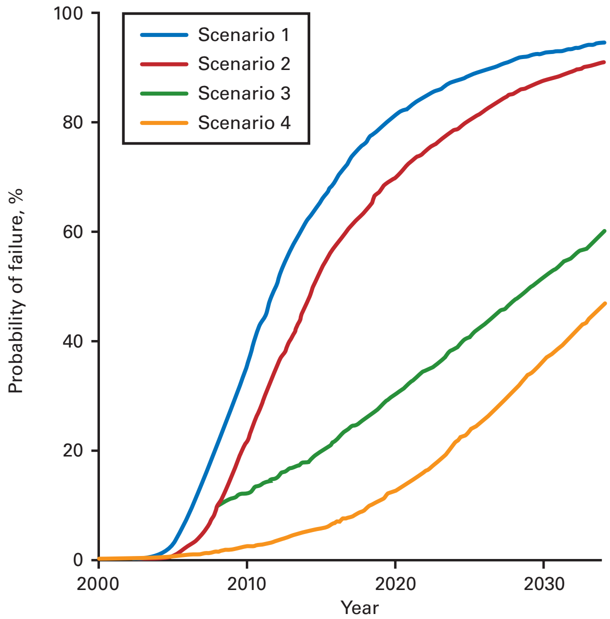
- Scenario 1: Continued operation with no pigging and the current inhibitor regime.
- Scenario 2: No pigging but implementation of an improved corrosion inhibitor program.
- Scenario 3: Pigging in 2008 followed by an improved inhibition program.
- Scenario 4: Pigging in 2004 followed by an improved inhibition program.

The time taken to reach minimum allowable wall thickness due to corrosion, starting from nominal wall thickness at the time of construction, defined pipeline failure for this analysis. Monte Carlo uncertainty modeling evaluated the effect of each scenario on the projected time to failure using the iDecide software package.

Historic operating conditions resulted in the internal surface of the pipe being heavily scaled, with a high accu-

UNCERTAINTY ASSESSMENT OUTPUT

Fig. 4



PROBABILITY OF FAILURE SUMMARY

Table 2

Scenario number	10% PoF	50% PoF (Year)	90% PoF
1—Current treatment regime	2006	2012	2027
2—Improved inhibition without pigging	2009	2015	2033
3—Pig in 2008, improved inhibition	2009	2029	2060
4—Pig in 2004, improved inhibition	2019	2034	2067

mulation of deposits. Simply increasing the availability of the corrosion inhibitor, therefore, would likely not result in the same increase in life extension expected from a highly effective inhibition program on a clean pipe surface.

Routine maintenance pigging will increase inhibitor efficiency, but its effects are not easily quantified. The uncertainty modeling approach, however, allowed quantification of this difference in life extension.

Analysis considered the following factors:

- Inhibitor efficiencies in terms of mitigating both general corrosion and pitting corrosion in a sour system.
- Realistic, achievable potential inhibitor availabilities and efficiencies from an optimized inhibition program applied to future operations.
- Improvements in inhibitor performance with regard to pitting corrosion, based on previous experience of inhibitor selection and inhibitor performance.

Table 1 shows the range of values taken for the different conditions, together with the type of distribution.

Results

Fig. 4 shows results of the Monte Carlo assessment as cumulative probability curves (S-curves) for the probability of pipeline failure (defined as time to MAWT) for the four different scenarios. A clear difference in the likelihood of failure exists, creating an equally clear difference in the risk associated with the different operating scenarios. The additional inhibitor efficiency pigging would provide in mitigating future pitting corrosion sharply deferred the likelihood of failure-perforation.

It is also clear that simply improving the inhibition program, without pigging the line to address the build-up of deposits, has only a marginal benefit on the line's longevity. By cleaning the line, pigging greatly improves the performance of the corrosion inhibitor at existing pits. In a system in which degradation is driven by localized corrosion, maximizing inhibitor efficiency has great benefits in deferring the potential time to failure.

Table 2 shows, even given the uncertain effect of pigging on inhibitor efficiency, modeling can still evaluate its potential effect on time to failure.

Enhanced inhibition alone only defers the time to 10% probability of failure by 3 years, while beginning routine pigging immediately defers it by 13 years. Deferment of 50% is again only 3 years for improved inhibition alone, increasing to 17 years with routine pigging commencing in 2008, but extending to 22 years by starting routine pigging immediately.

Simple inhibition, without regular cleaning, will almost certainly result in pipeline failure long before the design life of the pipeline.

While Fig. 4 and Table 2 clearly show the improvement in long-term integrity brought about by regular pigging, cost efficiency can also be identified by considering the effect of the additional operating costs for Scenarios 2, 3, and 4 as compared to Scenario 1 (maintaining the current inhibition program).

Cost estimates for an improved inhibitor program (covering higher dosage rates and improved availability) stood at an estimated $60,000/year; the cost of implementing a regular pigging operation (for the unmanned platforms) was estimated at $100,000/year; and the cost of a pipeline failure was estimated at $25 million.

Assuming a 5% interest rate allows calculation of the net present value, taking into account the operating costs each year as well as increased risk of failure. Table 3 shows the estimated net present value of the four different scenarios and relative costs over 10 years of operation.

ESTIMATED 20-YEAR COST EFFECTIVENESS Table 3

Scenario number	Net present value, $ million	Relative cost, %
1—Current treatment regime	9.52	100
2—Improved inhibition without pigging	7.68	81
3—Pig in 2008, improved inhibition	3.73	39
4—Pig in 2004, improved inhibition	2.00	21

Table 3 shows little benefit in simply adopting an improved inhibitor program, but significant benefit from incorporating routine pigging as soon as is practical.

Acknowledgment

The authors thank their coworkers for development of the overall procedure and the analysis of specific pipeline assessment. ✦

Reference

1. DNV-RP-G101, "Risk-based Inspection of Offshore Topsides Static Mechanical Equipment," Det Norske Veritas, 2002.

The authors

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Gareth John works for the Intertek group as a senior corrosion consultant at CAPCIS. He specializes in corrosion management, corrosion control (in particular cathodic protection), and corrosion monitoring and testing. Gareth joined CAPCIS more than 27 years ago, following completion of his PhD (1979) in corrosion science at University of Manchester Institute of Science and Technology. He is a member of the Royal Society of Chemistry, an Institute of Corrosion fellow, and a NACE International certified corrosion specialist.

New web mapping service

A new web mapping service (WMS) has been added to this firm's suite of web-based mapping products available to Eddy Watch subscribers.

The new product allows clients to import proprietary data into their own geographic information system (GIS). These data layers include tropical storm tracks, GPS drifter data, loop current and eddy fronts, satellite imagery, and forecast charts.

Once the WMS has been added to an end user's GIS, the layers continually update, eliminating the need for clients to add new layers just to update their maps. This new WMS seamlessly integrates into GIS applications such as Redlands, Calif.-based Environmental Systems Research Institute's ArcGIS and is compliant with the standards for web map services as laid out by Open Geospatial Consortium Inc., Wayland, Mass.

Source: **Horizon Marine Inc.,** 15 Creek Rd., Marion, MA 02738.

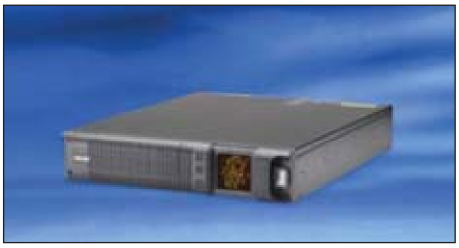
New UPS rated at 1.5-3 kVa

A new line of uninterruptible power systems (UPS) SSG Series UPS Plus models is rated at 1.5-3 kVA.

The company says its regenerative on-line UPS is an advanced, robust, and rugged solution that gives users a high level of power protection that can tolerate many of the elements found in the oil industry. The unit is capable of withstanding temperatures as high as 131° F.

The SSG Series UPS can be placed in an equipment rack or installed as a stand-alone tower, in close proximity to the critical load. This eliminates the need to shield the UPS from the environment. This point-to-point installation strategy helps save users the time and effort required to configure and wire elaborate power distribution for the various devices that need protection and helps lower the cost of installing UPSs, the firm notes.

The series also provides users an improved level of battery monitoring and replacement notification as well as user friendly, hot-swappable battery packs. Slide-out battery packs are easily replaced through the UPS front panel, without having to remove the UPS from the equipment rack, eliminating the handling of individual batteries and the associated wiring hassles.



The series is designed to give users the highest level of protection against a spectrum of power problems. It provides a continuous, clean, tightly regulated power source from the most polluted incoming AC power source, the firm points out.

Source: **Falcon Electric Inc.,** 5106 Azusa Canyon Rd., Irwindale, CA 91706.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4 10-12 2007	Districts 1-4 10-5 2007	District 5 10-12 2007	District 5 10-5 2007	Total US 10-12 2007	Total US 10-5 2007	Total US *10-13 2006
	1,000 b/d						
Total motor gasoline	1,074	1,301	19	22	1,093	1,323	676
Mo. gas. blending comp.	570	675	9	22	579	697	301
Distillate	302	385	—	—	302	385	271
Residual	437	307	67	—	504	307	135
Jet fuel-kerosine	117	169	74	77	191	246	399
Propane-propylene	210	154	3	1	213	155	237
Other	873	528	81	53	954	581	828
Total products	**3,583**	**3,519**	**253**	**175**	**3,836**	**3,694**	**2,847**
Total crude	**9,317**	**8,849**	**1,091**	**1,020**	**10,408**	**9,869**	**10,430**
Total imports	**12,900**	**12,368**	**1,344**	**1,195**	**14,244**	**13,563**	**13,277**

*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

	*10-19-07	*10-20-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	94.74	66.50	28.23	42.5
Brent crude	84.42	57.47	26.95	46.9
Crack spread	10.32	9.04	1.28	14.2
FUTURES MARKET PRICES				
One month				
Product value	93.72	67.11	26.60	39.6
Light sweet crude	87.84	58.37	29.47	50.5
Crack spread	5.88	8.75	–2.87	–32.8
Six month				
Product value	97.34	76.10	21.23	27.9
Light sweet crude	83.01	64.61	18.40	28.5
Crack spread	14.32	11.49	2.83	24.6

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

PURVIN & GERTZ LNG NETBACKS—OCT. 19, 2007

Receiving terminal	Liquefaction plant Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.71	4.62	5.88	4.51	5.22	5.85
Everett	5.88	4.18	5.49	4.30	4.33	6.19
Isle of Grain	7.15	5.13	6.48	5.08	5.55	6.56
Lake Charles	4.67	3.30	4.41	3.48	3.59	5.31
Sodegaura	5.43	7.64	5.63	7.33	6.64	4.87
Zeebrugge	6.43	4.47	5.80	4.41	4.87	5.82

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

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	16,218	50,244	23,334	10,590	60,954	13,702	4,898
PADD 2	62,932	48,129	15,984	7,008	28,690	1,257	22,894
PADD 3	174,295	62,699	28,443	13,655	32,452	15,542	29,667
PADD 4	14,140	6,007	1,831	567	2,536	330	[1]2,862
PADD 5	54,280	28,689	20,768	9,834	11,686	5,594	—
Oct. 12, 2007	**321,865**	**195,768**	**90,360**	**41,654**	**136,318**	**36,425**	**60,321**
Oct. 5, 2007	**320,081**	**193,000**	**87,575**	**41,353**	**135,324**	**36,566**	**60,516**
Oct. 13, 2006[2]	**335,550**	**210,175**	**92,396**	**42,778**	**145,399**	**42,300**	**72,001**

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

REFINERY REPORT—OCT. 12, 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	1,594	1,603	1,782	105	472	126	75
PADD 2	3,047	3,030	2,018	196	855	50	175
PADD 3	7,507	7,477	3,295	724	2,088	298	642
PADD 4	583	583	286	28	162	13	[1]138
PADD 5	2,508	2,430	1,483	416	595	157	—
Oct. 12, 2007	**15,239**	**15,123**	**8,864**	**1,469**	**4,172**	**644**	**1,030**
Oct. 5, 2007	**15,326**	**15,111**	**8,932**	**1,391**	**4,171**	**644**	**1,104**
Oct. 13, 2006[2]	**15,011**	**14,813**	**8,901**	**1,444**	**3,850**	**553**	**994**
	17,448 operable capacity		**87.3% 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 10-17-07	Pump price* 10-17-07	Pump price 10-18-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	244.4	284.1	207.1
Baltimore	231.0	272.9	215.1
Boston	226.7	268.6	226.7
Buffalo	223.8	283.9	231.9
Miami	252.9	303.2	230.8
Newark	238.0	270.9	226.7
New York	223.5	283.6	240.7
Norfolk	230.3	267.9	213.4
Philadelphia	228.5	279.2	231.8
Pittsburgh	229.9	280.6	230.6
Wash., DC	247.8	286.2	234.8
PAD I avg	234.3	280.1	226.3
Chicago	243.3	294.2	239.8
Cleveland	233.1	279.5	213.0
Des Moines	233.0	273.4	202.0
Detroit	240.8	290.0	224.0
Indianapolis	244.5	289.5	214.0
Kansas City	238.1	274.1	210.0
Louisville	252.6	289.5	207.0
Memphis	219.6	259.4	219.3
Milwaukee	245.5	296.8	226.7
Minn.-St. Paul	250.3	290.7	220.0
Oklahoma City	232.0	267.4	208.0
Omaha	225.2	271.6	220.0
St. Louis	227.3	263.3	216.2
Tulsa	227.4	262.8	205.0
Wichita	222.5	265.9	213.0
PAD II avg	235.7	277.9	215.9
Albuquerque	243.9	280.3	220.6
Birmingham	232.7	271.4	211.0
Dallas-Fort Worth	226.0	264.4	206.0
Houston	231.0	269.4	210.0
Little Rock	227.9	268.1	214.0
New Orleans	233.0	271.4	224.5
San Antonio	229.6	268.0	221.3
PAD III avg	232.0	270.4	215.3
Cheyenne	247.2	279.6	246.1
Denver	252.2	292.6	251.3
Salt Lake City	245.0	287.9	256.5
PAD IV avg.	248.1	286.7	251.3
Los Angeles	246.0	304.5	261.0
Phoenix	241.7	279.1	243.6
Portland	256.8	300.1	261.0
San Diego	256.6	315.1	265.0
San Francisco	263.9	322.4	276.0
Seattle	253.0	305.4	271.0
PAD V avg.	253.0	304.4	262.9
Week's avg.	**238.1**	**281.6**	**227.8**
Sept. avg.	**236.3**	**280.4**	**253.3**
Aug. avg.	**237.2**	**280.8**	**296.7**
2007 to date	**229.7**	**273.5**	—
2006 to date	**219,4**	**263.0**	—

*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

	10-12-07 ¢/gal		10-12-07 ¢/gal
Spot market product prices			
		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	223.08
New York Harbor	213.14	Gulf Coast	220.70
Gulf Coast	207.89	Gas oil	
Los Angeles	244.39	ARA	223.29
Amsterdam-Rotterdam-Antwerp (ARA)	186.40	Singapore	222.50
Singapore	211.43	Residual fuel oil	
Motor gasoline		New York Harbor	143.52
(Reformulated-regular)		Gulf Coast	148.21
New York Harbor	210.14	Los Angeles	158.30
Gulf Coast	207.64	ARA	156.80
Los Angeles	246.39	Singapore	159.02

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

BAKER HUGHES RIG COUNT

	10-19-07	10-20-06
Alabama	7	5
Alaska	8	6
Arkansas	48	25
California	42	34
Land	41	31
Offshore	1	3
Colorado	112	93
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	14	11
Kentucky	10	13
Louisiana	144	191
N. Land	51	58
S. Inland waters	25	18
S. Land	28	45
Offshore	40	70
Maryland	1	1
Michigan	1	1
Mississippi	9	14
Montana	12	17
Nebraska	1	0
New Mexico	70	88
New York	8	8
North Dakota	46	37
Ohio	14	9
Oklahoma	191	186
Pennsylvania	18	15
South Dakota	0	1
Texas	850	799
Offshore	8	15
Inland waters	2	3
Dist. 1	27	20
Dist. 2	30	31
Dist. 3	63	53
Dist. 4	80	94
Dist. 5	180	130
Dist. 6	124	120
Dist. 7B	38	47
Dist. 7C	54	40
Dist. 8	117	99
Dist. 8A	21	26
Dist. 9	40	46
Dist. 10	66	75
Utah	46	48
West Virginia	30	30
Wyoming	69	100
Others—NV-3; TN-5; VA-3	11	7
Total US	**1,764**	**1,739**
Total Canada	**331**	**455**
Grand total	**2,095**	**2,194**
Oil rigs	320	291
Gas rigs	1,438	1,442
Total offshore	50	89
Total cum. avg. YTD	**1,760**	**1,633**

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	10-19-07 Rig count	10-19-07 Percent footage*	10-20-06 Rig count	10-20-06 Percent footage*
0-2,500	59	5.0	48	—
2,501-5,000	104	59.6	91	48.3
5,001-7,500	220	21.8	226	18.1
7,501-10,000	436	2.5	414	2.8
10,001-12,500	433	1.6	444	2.2
12,501-15,000	280	0.3	249	0.4
15,001-17,500	111	—	118	—
17,501-20,000	69	—	70	—
20,001-over	33	—	31	—
Total	**1,745**	**7.5**	**1,691**	**6.3**
INLAND	39		40	
LAND	1,658		1,585	
OFFSHORE	48		66	

*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]10-19-07	[2]10-20-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	16	20
Alaska	763	699
California	652	682
Colorado	51	63
Florida	6	6
Illinois	31	28
Kansas	95	98
Louisiana	1,330	1,376
Michigan	15	14
Mississippi	50	47
Montana	93	90
New Mexico	169	144
North Dakota	109	115
Oklahoma	167	172
Texas	1,325	1,352
Utah	45	48
Wyoming	143	140
All others	60	69
Total	**5,120**	**5,163**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	10-19-07
Alaska-North Slope 27°	67.75
South Louisiana Sweet	88.50
California-Kern River 13°	77.25
Lost Hills 30°	85.20
Southwest Wyoming Sweet	80.60
East Texas Sweet	74.75
West Texas Sour 34°	79.50
West Texas Intermediate	85.25
Oklahoma Sweet	85.25
Texas Upper Gulf Coast	81.75
Michigan Sour	78.25
Kansas Common	84.25
North Dakota Sweet	75.50

*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]	10-12-07
United Kingdom-Brent 38°	78.66
Russia-Urals 32°	75.88
Saudi Light 34°	75.58
Dubai Fateh 32°	73.92
Algeria Saharan 44°	79.65
Nigeria-Bonny Light 37°	80.19
Indonesia-Minas 34°	80.83
Venezuela-Tia Juana Light 31°	74.17
Mexico-Isthmus 33°	75.06
OPEC basket	69.46
Total OPEC[2]	76.22
Total non-OPEC[2]	74.99
Total world[2]	75.66
US imports[3]	73.39

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume. NOTE: No new data at presstime.

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

US NATURAL GAS STORAGE[1]

	10-12-07	10-5-07	Change
	bcf		
Producing region	997	988	9
Consuming region east	1,932	1,907	25
Consuming region west	446	441	5
Total US	**3,375**	**3,336**	**39**
	July 07	**July 06**	**Change, %**
Total US[2]	**2,894**	**2,779**	**4.1**

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

Statistics

Imports of crude and products

	Districts 1-4 10-19 2007	Districts 1-4 10-12 2007	District 5 10-19 2007	District 5 10-12 2007	Total US 10-19 2007	Total US 10-12 2007	Total US *10-20 2006
	1,000 b/d						
Total motor gasoline	838	1,074	0	19	838	1,093	957
Mo. gas. blending comp.	435	570	0	9	435	579	494
Distillate	235	302	0	0	235	302	241
Residual	293	437	5	67	298	504	243
Jet fuel-kerosine	152	117	83	74	235	191	182
Propane-propylene	167	210	1	3	168	213	257
Other	919	873	67	81	986	954	853
Total products	**3,039**	**3,583**	**156**	**253**	**3,195**	**3,836**	**3,227**
Total crude	**8,133**	**9,317**	**970**	**1,091**	**9,103**	**10,408**	**9,494**
Total imports	**11,172**	**12,900**	**1,126**	**1,344**	**12,298**	**14,244**	**12,721**

*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

	*10-26-07	*10-27-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	95.28	67.70	27.59	40.7
Brent crude	84.70	57.91	26.79	46.3
Crack spread	10.58	9.78	0.79	8.1
FUTURES MARKET PRICES				
One month				
Product value	94.56	67.47	27.09	40.1
Light sweet crude	88.45	60.13	28.32	47.1
Crack spread	6.11	7.34	–1.23	–16.8
Six month				
Product value	98.72	75.78	22.94	30.3
Light sweet crude	84.25	64.87	19.38	29.9
Crack spread	14.46	10.92	3.55	32.5

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

Purvin & Gertz LNG netbacks—Oct. 26, 2007

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.71	4.60	5.87	4.50	5.21	5.84
Everett	5.51	3.97	5.12	4.05	4.57	5.82
Isle of Grain	8.48	7.65	7.86	7.54	7.64	7.87
Lake Charles	4.44	2.93	4.31	3.10	3.39	4.94
Sodegaura	5.28	7.63	5.48	7.19	6.49	4.71
Zeebrugge	6.43	4.66	5.79	4.56	5.10	5.81

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	14,945	49,852	22,983	11,265	60,908	14,114	4,951
PADD 2	61,206	47,704	15,567	7,607	27,373	1,259	23,387
PADD 3	170,837	62,724	28,445	12,972	31,973	15,714	29,669
PADD 4	14,634	6,022	1,571	622	2,422	329	[1]2,952
PADD 5	54,955	27,535	20,553	9,462	11,795	5,323	—
Oct. 19, 2007	**316,577**	**193,837**	**89,119**	**41,928**	**134,471**	**36,739**	**60,959**
Oct. 12, 2007	**321,865**	**195,768**	**90,360**	**41,654**	**136,318**	**36,425**	**60,374**
Oct. 20, 2006[2]	**332,345**	**207,416**	**92,960**	**41,580**	**143,981**	**41,815**	**71,961**

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

Refinery report—Oct. 19, 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	1,592	1,611	1,873	74	511	138	80
PADD 2	3,049	3,025	2,020	217	845	46	177
PADD 3	7,489	7,305	3,220	725	1,895	304	636
PADD 4	539	539	312	17	157	13	[1]131
PADD 5	2,533	2,460	1,573	376	538	208	—
Oct. 19, 2007	**15,202**	**14,940**	**8,998**	**1,409**	**3,946**	**709**	**1,024**
Oct. 12, 2007	**15,239**	**15,123**	**8,864**	**1,469**	**4,172**	**644**	**1,030**
Oct. 20, 2006[2]	**14,994**	**14,871**	**8,687**	**1,442**	**4,081**	**625**	**959**
	17,448 operable capacity		**87.1% 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 10-24-07	Pump price* 10-24-07	Pump price 10-25-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	245.6	285.3	203.0
Baltimore	233.0	274.9	211.0
Boston	228.2	270.1	222.8
Buffalo	225.1	285.2	227.9
Miami	254.0	304.3	226.9
Newark	241.3	274.2	222.8
New York	225.0	285.1	236.8
Norfolk	232.3	269.9	210.4
Philadelphia	229.6	280.3	227.9
Pittsburgh	231.4	282.1	226.8
Wash., DC	250.3	288.7	230.9
PAD I avg	236.0	281.8	222.5
Chicago	243.8	294.7	233.2
Cleveland	234.0	280.4	212.9
Des Moines	234.0	274.4	201.9
Detroit	241.4	290.6	223.9
Indianapolis	245.4	290.4	213.9
Kansas City	238.0	274.0	209.9
Louisville	253.5	290.4	206.9
Memphis	220.6	260.4	219.0
Milwaukee	245.9	297.2	222.8
Minn.-St. Paul	250.8	291.2	219.9
Oklahoma City	232.3	267.7	207.9
Omaha	225.7	272.1	219.9
St. Louis	228.0	264.0	216.0
Tulsa	227.5	262.9	204.9
Wichita	222.8	266.2	212.9
PAD II avg	236.3	278.4	215.1
Albuquerque	246.3	282.7	219.5
Birmingham	235.7	274.4	210.9
Dallas-Fort Worth	227.0	265.4	205.9
Houston	232.0	270.4	209.9
Little Rock	229.8	270.0	213.9
New Orleans	234.0	272.4	218.8
San Antonio	230.9	269.3	215.0
PAD III avg	233.7	272.1	213.4
Cheyenne	247.4	279.8	232.6
Denver	254.4	294.8	237.7
Salt Lake City	247.3	290.2	241.4
PAD IV avg.	249.7	288.3	237.3
Los Angeles	252.3	310.8	254.3
Phoenix	236.2	273.6	240.5
Portland	258.7	302.0	253.6
San Diego	262.5	321.0	261.6
San Francisco	273.6	332.1	272.6
Seattle	258.0	310.4	263.6
PAD V avg.	256.9	308.3	257.7
Week's avg.	**239.7**	**283.2**	**224.4**
Sept. avg.	**236.3**	**280.4**	**228.0**
Aug. avg.	**237.2**	**280.8**	**253.3**
2007 to date	**230.1**	**273.7**	**—**
2006 to date	**218.5**	**262.1**	**—**

*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

	10-19-07 ¢/gal
Motor gasoline	
(Conventional-regular)	
New York Harbor	221.28
Gulf Coast	214.90
Los Angeles	235.15
Amsterdam-Rotterdam-Antwerp (ARA)	200.70
Singapore	217.57
Motor gasoline	
(Reformulated-regular)	
New York Harbor	218.70
Gulf Coast	216.15
Los Angeles	237.15

	10-19-07 ¢/gal
Heating oil	
No. 2	
New York Harbor	231.38
Gulf Coast	229.00
Gas oil	
ARA	232.01
Singapore	233.10
Residual fuel oil	
New York Harbor	153.88
Gulf Coast	160.48
Los Angeles	163.96
ARA	163.39
Singapore	168.98

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

BAKER HUGHES RIG COUNT

	10-26-07	10-27-06
Alabama	7	5
Alaska	8	7
Arkansas	49	26
California	42	34
Land	41	31
Offshore	1	3
Colorado	110	92
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	14	11
Kentucky	9	14
Louisiana	158	192
N. Land	59	59
S. Inland waters	26	19
S. Land	31	43
Offshore	42	71
Maryland	1	0
Michigan	1	3
Mississippi	12	14
Montana	11	17
Nebraska	0	0
New Mexico	74	89
New York	8	9
North Dakota	49	38
Ohio	14	8
Oklahoma	188	187
Pennsylvania	18	14
South Dakota	0	1
Texas	828	801
Offshore	8	15
Inland waters	2	3
Dist. 1	23	21
Dist. 2	23	30
Dist. 3	63	51
Dist. 4	89	94
Dist. 5	181	131
Dist. 6	113	126
Dist. 7B	34	51
Dist. 7C	53	41
Dist. 8	117	96
Dist. 8A	20	22
Dist. 9	42	44
Dist. 10	60	76
Utah	44	45
West Virginia	31	30
Wyoming	72	101
Others—NV-2; TN-6; VA-2	10	6
Total US	**1,760**	**1,744**
Total Canada	**345**	**343**
Grand total	**2,105**	**2,087**
Oil rigs	326	289
Gas rigs	1,428	1,450
Total offshore	52	90
Total cum. avg. YTD	**1,760**	**1,636**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

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

SMITH RIG COUNT

Proposed depth, ft	10-26-07 Rig count	10-26-07 Percent footage*	10-27-06 Rig count	10-27-06 Percent footage*
0-2,500	56	5.3	47	2.1
2,501-5,000	97	59.7	92	50.0
5,001-7,500	229	24.8	229	16.1
7,501-10,000	437	1.8	405	2.7
10,001-12,500	453	2.8	443	2.2
12,501-15,000	274	0.7	245	0.8
15,001-17,500	114	—	113	—
17,501-20,000	69	—	72	—
20,001-over	33	—	32	—
Total	**1,762**	**8.0**	**1,678**	**6.3**
INLAND	40		36	
LAND	1,674		1,578	
OFFSHORE	48		64	

*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]10-26-07	[2]10-27-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	16	20
Alaska	770	714
California	644	783
Colorado	51	63
Florida	5	6
Illinois	31	28
Kansas	96	98
Louisiana	1,337	1,368
Michigan	15	14
Mississippi	50	47
Montana	94	86
New Mexico	171	137
North Dakota	109	116
Oklahoma	168	172
Texas	1,332	1,359
Utah	45	48
Wyoming	144	139
All others	60	67
Total	**5,138**	**5,165**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	10-19-06
Alaska-North Slope 27°	67.75
South Louisiana Sweet	91.75
California-Kern River 13°	80.35
Lost Hills 30°	88.15
Southwest Wyoming Sweet	83.86
East Texas Sweet	87.75
West Texas Sour 34°	82.50
West Texas Intermediate	88.25
Oklahoma Sweet	88.25
Texas Upper Gulf Coast	84.75
Michigan Sour	81.25
Kansas Common	87.50
North Dakota Sweet	78.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	10-19-07
United Kingdom-Brent 38°	83.61
Russia-Urals 32°	81.00
Saudi Light 34°	80.16
Dubai Fateh 32°	77.23
Algeria Saharan 44°	84.67
Nigeria-Bonny Light 37°	85.15
Indonesia-Minas 34°	84.74
Venezuela-Tia Juana Light 31°	80.29
Mexico-Isthmus 33°	80.18
OPEC basket	69.46
Total OPEC[2]	80.58
Total non-OPEC[2]	79.59
Total world[2]	80.12
US imports[3]	77.84

[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]

	10-19-07	10-12-06	Change
	Bcf		
Producing region	1,020	997	23
Consuming region east	1,970	1,932	38
Consuming region west	453	446	7
Total US	**3,443**	**3,375**	**68**
	July 07	**July 06**	**Change, %**
Total US[2]	**2,894**	**2,779**	**4.1**

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

PACE REFINING MARGINS

	Aug. 2007	Sept. 2007	Oct. 2007	Oct. 2006	Change	Change, %
	$/bbl				2007 vs. 2006	
US Gulf Coast						
West Texas Sour	14.20	13.28	10.30	10.59	–0.29	–2.7
Composite US Gulf Refinery	14.88	15.24	12.20	9.93	2.27	22.9
Arabian Light	11.33	12.56	9.28	10.56	–1.28	–12.1
Bonny Light	8.41	8.94	6.65	2.76	3.88	140.5
US PADD II						
Chicago (WTI)	20.24	13.77	9.06	8.94	0.12	1.3
US East Coast						
NY Harbor (Arab Med)	12.60	13.25	11.67	9.33	2.34	25.1
East Coast Comp-RFG	15.44	15.92	14.02	11.72	2.29	19.6
US West Coast						
Los Angeles (ANS)	8.73	9.46	13.13	12.78	0.34	2.7
NW Europe						
Rotterdam (Brent)	4.52	3.67	3.20	2.83	0.37	13.2
Mediterranean						
Italy (Urals)	8.15	9.79	8.65	7.27	1.38	18.9
Far East						
Singapore (Dubai)	6.16	4.68	5.72	0.37	5.36	1,464.8

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	July 2007	June 2007	July 2006	July 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,700	1,547	1,766	–66	13,706	12,966	740
Addition to storage	397	437	305	92	2,115	1,579	536
Exports	66	64	60	6	473	416	57
Canada	31	29	17	14	256	179	77
Mexico	32	32	37	–5	189	198	–9
LNG	3	3	6	–3	28	39	–11
Total demand	**2,163**	**2,048**	**2,131**	**32**	**16,294**	**14,961**	**1,333**
SUPPLY							
Production (dry gas)	1,623	1,568	1,563	60	10,920	10,676	244
Supplemental gas	5	5	5	—	35	35	—
Storage withdrawal	84	48	144	–60	2,115	1,579	536
Imports	383	370	372	11	2,674	2,433	241
Canada	284	283	314	–30	2,093	2,073	20
Mexico	—	—	—	—	18	3	15
LNG	99	87	58	41	563	357	206
Total supply	**2,095**	**1,991**	**2,084**	**11**	**15,744**	**14,723**	**1,021**

NATURAL GAS IN UNDERGROUND STORAGE

	July 2007	June 2007	May 2007	July 2006	Change
	bcf				
Base gas	4,229	4,230	4,251	4,214	15
Working gas	2,894	2,580	2,179	2,779	115
Total gas	**7,123**	**6,810**	**6,430**	**6,993**	**130**

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

WORLDWIDE NGL PRODUCTION

	July 2007	June 2007	7 month average – Production – 2007	2006	Change vs. previous year Volume	%
	1,000 b/d					%
Brazil	79	83	83	85	–2	–2.0
Canada	659	697	705	685	20	2.9
Mexico	378	418	409	439	–30	–6.9
United States	1,778	1,775	1,747	1,725	23	1.3
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	199	197	205	214	–9	–4.0
Western Hemisphere	**3,293**	**3,370**	**3,349**	**3,347**	**2**	**0.1**
Norway	279	246	289	286	4	1.2
United Kingdom	121	123	150	155	–5	–3.2
Other Western Europe	11	11	10	11	—	–2.9
Western Europe	**410**	**380**	**449**	**451**	**–2**	**–0.4**
Russia	425	424	426	413	13	3.1
Other FSU	160	160	160	160	—	—
Other Eastern Europe	14	14	15	17	–2	–13.4
Eastern Europe	**599**	**598**	**601**	**590**	**11**	**1.8**
Algeria	340	340	340	301	39	13.1
Egypt	70	70	70	73	–3	–4.1
Libya	80	80	80	86	–6	–7.0
Other Africa	182	188	186	189	–3	–1.8
Africa	**672**	**678**	**676**	**649**	**27**	**4.2**
Saudi Arabia	1,427	1,427	1,427	1,427	—	—
United Arab Emirates	250	250	250	250	—	—
Other Middle East	871	870	870	901	–31	–3.5
Middle East	**2,548**	**2,547**	**2,547**	**2,578**	**–31**	**–1.2**
Australia	80	80	75	80	–6	–7.0
China	180	180	180	180	—	—
India	—	—	5	43	–37	–87.3
Other Asia-Pacific	172	172	178	186	–8	–4.4
Asia-Pacific	**432**	**432**	**438**	**489**	**–51**	**–10.5**
TOTAL WORLD	**7,954**	**8,006**	**8,060**	**8,105**	**–45**	**–0.6**

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

OXYGENATES

	Aug. 2007	July 2007	Change	YTD 2007	YTD 2006	Change
	1,000 bbl					
Fuel ethanol						
Production	13,458	13,051	407	97,659	74,002	23,657
Stocks	10,309	9,696	613	10,309	9,160	1,149
MTBE						
Production	1,985	2,088	–103	15,624	23,659	–8,035
Stocks	1,382	1,480	–98	1,382	1,759	–377

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

US COOLING DEGREE-DAYS

	Sept. 2007	Sept. 2006	Normal	2007 % change from normal	Total degree days Jan. 1 through Sept. 30 2007	2006	Normal	% change from normal
New England	71	13	28	153.6	544	554	417	30.5
Middle Atlantic	105	29	61	72.1	799	767	659	21.2
East North Central	121	25	66	83.3	863	724	720	19.9
West North Central	132	50	94	40.4	1,085	1,036	934	16.2
South Atlantic	318	244	263	20.9	1,969	1,887	1,770	11.2
East South Central	303	193	214	41.6	1,853	1,687	1,500	23.5
West South Central	393	318	348	12.9	2,284	2,562	2,294	–0.4
Mountain	197	140	177	11.3	1,446	1,351	1,239	16.7
Pacific	117	140	130	–10.0	770	907	707	8.9
US average*	**199**	**135**	**160**	**24.4**	**1,302**	**1,293**	**1,162**	**12.0**

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

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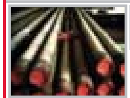

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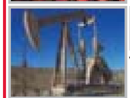

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Mortgage crunch a reminder of economic cycles

The US treasury secretary offered lessons all around—some related to oil and gas—in a stinging Oct. 16 speech about the meltdown of housing finance.

Henry M. Paulson Jr. had few comforting words for his audience at the Georgetown University Law Center in Washington, DC.

While the US economy remains strong, he said, it has been wounded by a housing slump caused in part by "shameful" lending practices and won't fully recover until housing starts rebound—a turn not yet in sight.

The Editor's Perspective

by Bob Tippee, Editor

Paulson noted fragmentation of the mortgage lending industry into parts that originate, package, and invest in mortgage loans. And he regretted a proliferation of nontraditional adjustable rate mortgages (ARMs) coupled with increased lending to borrowers not qualifying for the lowest interest rates.

About one fourth of the mortgage originations in 2005 and 2005 were nontraditional ARMs, many with risky features such as low teaser rates and interest-only payments. Subprime lending grew from 2% of mortgages in 1998 to 14% in mid-2007.

"A significant percentage of the nontraditional ARMs were marketed and sold to subprime borrowers," Paulson said. At another point he called for "a higher level of integrity" in mortgage origination. "Some of the conduct and practices that I have learned about are shameful."

Still, he said, "homebuyers have a responsibility to understand their mortgages."

That's easy to overlook when words like "shameful" are being used in high places to describe an industry.

How hard is it to see the risk here? If you take out an adjustable-rate loan you can barely afford when interest rates are low, you get hammered when rates rise.

That's not "if" rates rise; it's "when" they do. In an economy, everything cycles. Most ARM borrowers surely saw the risk of an adverse interest-rate turn. They just thought it wouldn't happen.

How many Americans similarly bought sport utility vehicles or monster pickup tricks on the assumption that fuel prices would stay low forever?

Oil prices, like interest rates, cycle. They never stay low, and buyers of beamy vehicles were wrong to expect them to.

Lest anyone forget, oil prices never stay high, either.

(Online Oct. 19, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Facing $100/bbl oil

The December contract for benchmark US light, sweet crudes climbed as high as $92.22/bbl during the regular trading session Oct. 26 on the New York Mercantile Exchange before closing at $91.86, up $1.40 for the day.

It was the second time in as many sessions that contract hit new highs above $90/bbl after crossing that mark for the first time on Oct. 18. Moreover, the contract's price continued to climb pass $93/bbl in after-hours electronic trading over the weekend and appeared set to scale new heights before expiring.

"The oil market may be only one or two events away from $100-plus oil, and there is much momentum in that direction," said Daniel Yergin, chairman of Cambridge Energy Research Associates, at an Oct. 29 energy symposium at Georgetown University in Washington, DC. "With prices over $90/bbl and strong anticipation of $100, the oil market is showing signs of high fever, stoked by fears of clashes in the Middle East and resulting disruptions of supply."

Analysts in the Houston office of Raymond James & Associates Inc. cited several factors pushing crude prices higher, including:

- Storms in the Gulf of Mexico forced Petroloeos Mexicanos, Mexico's state-run oil company, to shut in 600,000 b/d of offshore production, one-fifth of Mexico's total oil output.
- The US dollar hit record lows against the euro, as investors anticipated that the US Federal Reserve will cut interest rates at its next meeting.
- Ministers of the Organization of Petroleum Exporting Countries have disregarded calls from various sources to increase production. Instead, OPEC blames geopolitical issues for driving up prices.
- Increased military tensions between Turkey and Kurdish rebels in Iraq.

Turkey and Iraq

Turkey's threat to invade northern Iraq and attack bases of the Kurdistan Workers' Party (PKK) , "has sent prices spiraling upwards, primarily because the words 'conflict' and 'Middle East' always cause traders to respond with alarm," said Michael C. Lynch, president of Strategic Energy & Economic Research Inc., Amherst, Mass. However, Lynch said, "The Turks are unlikely to do much more than cross into border regions and attack the mountain bases near there, which are well away from any oil producing areas (located mostly near Kirkuk, over 200 km from the border)." He said, "Some military action can be expected, but it is unlikely to be major and should be dismissed by the market fairly quickly."

Meanwhile, Yergin said, "Oil prices are becoming increasingly decoupled from the fundamentals of supply and demand." He said, "What we're seeing in the oil market today is rooted more in the cauldrons of geopolitics and the impact of financial markets, expectations, and psychology than in supply and demand, but these are real factors." He cited the impact on the energy market over the previous 2 weeks of tougher rhetoric over Iran's nuclear program and heightened tension between Turkey and Iraq.

Yergin emphasized the importance of Russia in global energy markets in this decade. "While there has been so much attention around the world to the rapid increase in Chinese oil consumption, the growth in Russian oil production between 2000 and 2006—2.9 million b/d—exceeded the 2.5 million b/d increase in Chinese oil demand over the same period," he said. "But while Chinese consumption continues to go up, Russia's increase in output is flattening out rapidly owing to swiftly rising costs and very high government taxes on oil production."

He told the Georgetown University conference, "Although publics and governments around the world are focused on prices, one of the most important factors in the world oil industry is the rapid rise in costs owing to shortages of people, equipment, and skills."

Natural gas

Natural gas has become "arguably the most contentious issue" between Europe and Russia, which is the world's largest producer of natural gas and the major exporter to Europe, Yergin said. A new CERA study of the gas interdependence between Europe and Russia shows "structural reasons" for that tension, because of major changes in Russia, Europe, and the international gas market itself over the last decades.

The US National Petroleum Council estimates world energy consumption is likely to increase by 50-60% over the next quarter century, Yergin said. "Meeting that demand in an environmentally-sound way will be a very major challenge for all energy-producing countries, including both Russia and the US," he said. "And the results will have a decisive impact on how nations define their energy security and what they do about it."

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


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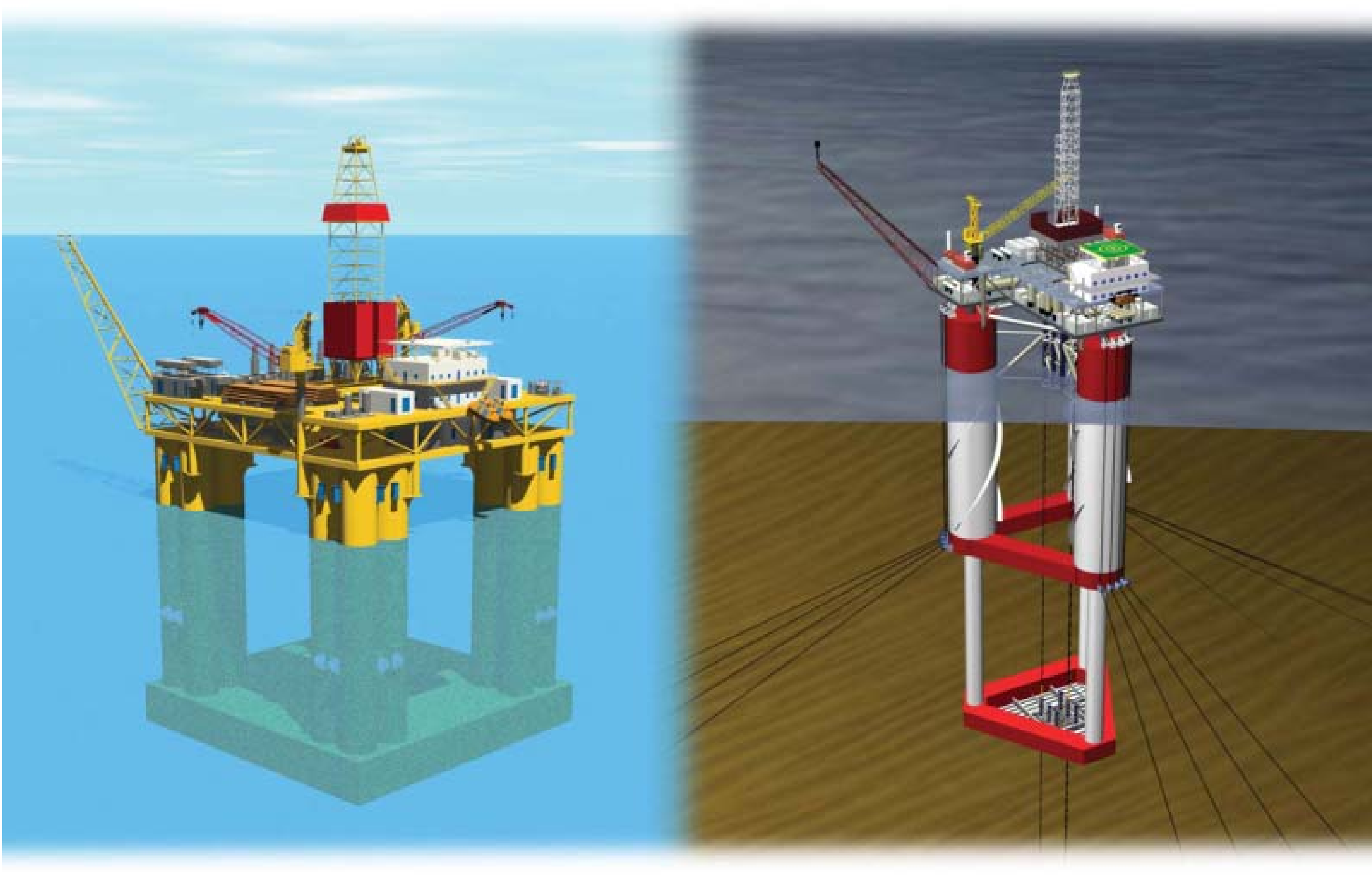
Deepwater Equipment & Services

Supplement to *Oil & Gas Journal* • November 5, 2007



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Technology Forum

Deepwater Equipment & Services

Supplement to *Oil & Gas Journal* • November 5, 2007

4 Costs, environmental/safety issues top deepwater concerns

5 Future designs emerging for floaters, subsea systems

7 New technology solutions advancing deepwater capability

Two new deepwater floating production facility designs were recently reviewed by ABS. The Multicolumn Floater (MCF) shown at left was developed by AGR Deepwater Development Systems Inc. The MinDOC3 design shown at right was developed by Alden "Doc" Laborde and William Bennett over 8 years in concert with a consortium of leading deepwater companies. The MinDOC3 technology is owned by Durward International, a joint venture of Keppel FELS and TexBass.
Images courtesy of AGR (MCF) and Bennett & Associates LLC (MinDOC3).

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Costs, environmental/safety issues top deepwater concerns

Companies that provide equipment and services to the deepwater oil and gas operations sector see little prospect that soaring costs will be reined in anytime soon.

New productivity solutions are offered to help cope with the shortages of drilling rigs and qualified personnel that are contributing to those rising costs. Adding to cost pressures are new design criteria being implemented in the wake of the devastating hurricanes in the Gulf of Mexico in recent years. Environmental concerns also remain paramount in the deepwater service and supply sector. Evolving technology is spawning new deepwater designs to address productivity, efficiency, safety, and environmental challenges, particularly for the deepwater Gulf of Mexico.

Soaring costs

The supply chain for drilling rigs is still quite strained and appears to remain so through 2010, according to Eric H. Namtvedt, president of FloaTEC.

"We are still seeing operators and drilling contractors call on options for late 2010/early 2011 deliveries, and, more importantly, that is the time frame when a large number of floating production platforms will be competing for the same yard and equipment capacities," he says. "The bottom line is that we will see continued 'high activity' for the foreseeable future."

Gary Shaw, technology leader, VetcoGray, a GE Oil & Gas business, contends that the primary driver for the higher costs in deep water mostly has to do with the rig cost and not the equipment costs: "That said, we have seen large increases in our part of the business as well due to the escalating cost of raw materials. The [rig cost] is partly linked to the complex systems required onboard a deepwater drilling vessel and partly the price of oil; the [equipment cost] has to do with the developing economies and their appetite for raw material. As long as the drivers are the same, the deepwater development cost is likely to remain high."

Brian Skeels, emerging technology manager, FMC Technologies, doesn't see any near-term letup in high costs in the deepwater drilling and production sector.

"It's a simple case of supply and demand in a 'construction' bidding market," he says. "Dayrates will soften when either MODU [mobile offshore drilling unit] demand softens, the rig count goes up, and/or alternative methods play a (secondary) role to divert some of the demand needed for well workovers/interventions."

Among the alternative methods that Skeels sees as possible solutions to accommodate continuing strong demand for deepwater drillings rigs—beyond the obvious one of more newbuilds to address drilling and completion needs—are efforts to "1) continue to work with ideas to leverage smaller ('lesser-generation') drilling rigs to artificially extend their capability using slimbore drilling and drilling risers, free-standing risers, preset moorings, etc.; and 2) bring to the marketplace light well (i.e., rigless) intervention for workovers and other subsea maintenance jobs."

Namtvedt also contends that "reliability and operability will be key for deepwater rig providers to get the needed productivity out of the high unit cost—thus companies with experienced crews and a strong network of subcontractors and supplier infrastructure in place will be preferred."

The same situation applies to the fabrication community, he adds: "Unfortunately, I think we will see a number of 'train wrecks' before the current rig construction backlog has been delivered."

The supply chain for drilling rigs is still quite strained and appears to remain so through 2010

— Eric H. Namtvedt, FloaTEC

Uri G. Nooteboom, vice-president, field development projects for INTEC, notes that drilling, manufacturing, and installation contractors are loaded to capacity with the wave of development projects that is moving though the system right now.

"Once these development projects have been delivered—say, 2009–10—the manufacturing/installation industry may see a slowdown from current levels since exploration has lagged behind and many projects are being delayed because of cost concerns," he points out. "As a result, costs are likely to stabilize or possibly come down from their current levels. As usual, this is a self-governing cycle."

Environmental/safety concerns

The continuing plunge into ever-deeper waters is resulting in new designs and design criteria to address environmental and safety concerns.

Namtvedt thinks that new design criteria for post-Katrina Gulf of Mexico will drive the size of platforms and moorings, and deep target drilling such as subsalt will further impact a need for high payload capacities.

"FloaTEC has proven solutions, from our portfolio of spar, TLP, or semisubmersible, that optimize payload to steel and buoyancy and thus minimize the size of our platform solutions," he says. "Solutions that allow for quay-side integration (TLP and semi) reduce the need for extensive offshore lifts and integration work in exposed offshore locations, with corresponding risks for delays."

Regarding environmental issues, Namtvedt contends that emerging new guidelines requiring zero discharge to air and water will further impact platform designs to be able to handle more equipment and larger payloads.

Despite industry's excellent track record with regard to accidental discharges, Shaw points out that the release of even environmentally friendly fluids such as water-based control fluids are starting to come under scrutiny by the industry.

"We are developing new products that minimize or eliminate the use of traditional hydraulic power," he says. "Another promising area is in the development of materials and coatings that reduce the amount of grease used in our products."

Shaw also cites requirements on control and process facilities for zero-emission production that are a common concern for both deepwater and arctic designs. "We are looking at active internals for subsea processing (giving reduced chemical requirements), thermal insulation alternatives (giving reduced needs for hydrate, wax, and scale inhibition chemicals), and solutions to reduce the need for hydraulics," he notes. "Subsea processing facilities also show significant potential to reduce the environmental footprint of a subsea facility because the increased flexibility in the design will allow for increased efficiency in the boosting facility."

"It should also be noted that systems like HIPPS [high-integrity pipeline protection systems] and subsea processing may show a significantly smaller carbon footprint because they offer a possibility to reduce overall steel volumes."]

"Once these development projects have been delivered—say, 2009–10—the manufacturing/installation industry may see a slowdown from current levels since exploration has lagged behind and many projects are being delayed because of cost concerns."

— Uri G. Nooteboom, INTEC

Future designs emerging for floaters, subsea systems

As the offshore oil and natural gas industry continues its march into deepwater frontiers, the facilities that will be the mainstays of that push, subsea installations and floating production facilities, will take on a distinctively different look.

Much of the design changes will entail borrowing the basic concepts in use today and reconfiguring them in new ways. Other hallmarks of tomorrow's deepwater production facilities will be increased automation, more modularization, improved size/weight ratios, longer tiebacks, and expanded use of subsea processing.

Tomorrow's subsea installations

The days when all of the equipment and trees mounted on one-of-a-kind giant templates with integrated and form-fitting piping and connections are fading into the past, claims Brian Skeels, emerging technology manager, FMC Technologies.

"Clustered wells leading to manifolds connected by umbilical flying leads and jumper connections allow for smaller modular components that can be set on the seafloor side-by-side and then connected up," he says. "This modular approach also lends itself to easier installation and a pay-as-you-go schedule. Subsea production facilities can be added later in a modular plug-and-play scenario to deal with production plateaus or changes in well count. Smart subsea field architects will add plug-in bases in the field pipelines that can accommodate the later installation of more infrastructure when it's needed, without disturbing what was initially installed.

"Daisy-chained pipeline loop (like Canyon Express) or field hub (like Independence) approaches to field development will be the norm, since most oil companies will have to form consortiums to share in the infrastructure costs."

Finally, oil and gas companies are accepting the notion that subsea metering, boosting, and separation are smart and economical means to address both infrastructure-lean areas of the world and longer offset distances, Skeels contends: "The bigger picture is getting the overall recovery rates of subsea fields up to be on par with conventional platform completions for the same cost."

Olivier Saincry, Doris Engineering subsea systems manager, foresees the optimization of subsea system installations "residing in the use of autonomous equipment, maintenance work without the use of surface support vessels, and a number of topside processes being done subsea, limiting the number of links between the seabed and surface."

Eric H. Namtvedt, president of FloaTEC, thinks that the optimized subsea solution will involve new technologies such as subsea processing and boosting, ESPs, all-electric systems to enable further step-outs, and compact tree designs.

Uri G. Nooteboom, vice-president, field development projects for INTEC, contends that the deepwater sector will see more long-distance tiebacks to existing infrastructure or all the way to the beach: "Distances will continue to increase, using technologies such as subsea pumping/compression, subsea processing, flowline heating, efficient subsea power delivery/generation, etc."

Within the next 10 years, predicts Gary Shaw, technology leader, VetcoGray, a GE Oil & Gas business, the complete subsea processing plant is likely to become a reality where fluids and gas are extracted from the reservoir, analyzed, separated by fluid type, treated, and then pumped to processing facilities—or in the case of gas, compressed and then sent to be processed.

"In addition, it is also possible that the power to drive all this will be 'resident subsea' as well," he says. "Many of the pieces of this puzzle are already being worked, beginning with the Troll subsea separation project that VetcoGray installed in 1999.

"This new subsea facility will also be managed by an advanced control system using powerful software and a multitude of seabed sensors to actively help maximize the hydrocarbon extraction rate."

Tomorrow's floating production facility

Kenneth Richardson, ABS vice-president of energy development, details these general criteria for the optimized floating production facility of the future:

- A local control station for subsea production and processing.
- An "incredible" amount of automation, thus permitting minimal personnel onboard and an uplink to a remote control site capable of long-term production management.
- A design that is current-friendly and event-survivable.
- A design that allows for maximum operation up-time.

"There are many designs and options out there," he points out. "ABS marine engineers and naval architects conducting plan design reviews worldwide report many new designs are combining the basic ideas from spars, tension leg platforms, and semisubmersibles and arranging them in new configurations."

From a class society perspective, the issue is which existing rules or risk methodologies should be applied so that the review of these new units can be undertaken to standards that offer safety levels comparable to more-traditional designs, Richardson notes.

"Many of these novel designs are destined for the Gulf of Mexico," he says. "However, ABS offshore project development staff say they are also beginning to see increased interest in novel concepts for service in other parts of the world."

Among some examples he cites is the MinDOC3 design from Alden "Doc" Laborde and William Bennett, designed over a period of 8 years in concert with a consortium of industry-leading firms. (The technology is currently owned by Durward International, a joint venture of Keppel FELS and Tex-Bass.) Another example is the multicolumn floater from AGR Deepwater Development Systems Inc.

The optimization of subsea system installations "[will reside] in the use of autonomous equipment, maintenance work without the use of surface support vessels, and a number of topside processes being done subsea, limiting the number of links between the seabed and surface."

— Olivier Saincry, Doris Engineering

"It is not so much the technologies that are changing as it is combining or packaging the technologies in a different manner," contends Richardson. "We may see a design that is a cross between a semisubmersible and a truss spar. For ABS, the question then becomes: How do we analyze and review the design in terms of its stability?"

Another instance has been a recent semisubmersible design that ballasts not like a semi but like a spar, he says, adding that this "passive hull" design is the first to have been incorporated within a Gulf of Mexico semisubmersible recently.

Other experts interviewed focused on weight and size ratios.

"The optimization of the floating production facility will be in the equipment that it carries (weight and size optimization) and the ease of fabrication/standardization of the floater," says Saincry.

Namtvedt expands on that point, noting that in floating platform design, there is usually a trade-off between size and efficiency.

"The more 'payload' that is included on one platform, the less you pay for the 'real estate' per installed equipment; however, as the complexity increases and interdependencies of platform systems go up, so does the higher probability for something to go wrong, thereby shutting down total operation," he says. "As a solution provider, FloaTEC is working on finding this balance for maximum efficiency in operations, while ensuring that the design and fabrication also come together in a construction-friendly manner. Given the 'drivers' coming from moving into harsher environments and increasing water and reservoir depths, I think we will see both small and highly targeted solutions, while certain field sizes and complexities will require even larger integrated platforms. Smaller, simpler designs and systems will ultimately provide better value."

Skeels thinks that the spar will be floating production facility of the future.

"Its stability and storage capacity are only now being exploited, and its design can accommodate several drilling and production scenarios," he says. "Gathering pipelines and sales lines will be accommodated by vertical production risers inside the spar's hull. Deepwater steel catenary risers (SCRs), their weight, and offset distance will have to be rethought out for ultradeep water. Independence Hub may be the near-term practical limit for semisubmersible floating production facilities supporting SCRs in 8,000 feet of water."

"It is not so much the technologies that are changing as it is combining or packaging the technologies in a different manner. We may see a design that is a cross between a semisubmersible and a truss spar."

— Kenneth Richardson, ABS

Shaw believes that producing fields requiring more frequent well intervention may favor a dry tree platform.

He adds, "Escalating costs in benign environments may make us think more seriously about production to floating barges. FPSOs are on the horizon in the Gulf of Mexico, and there are numerous subsea developments being planned around the world. The optimum production facility depends on several factors that change with locality as well as with time."]

New technology solutions advancing deepwater capability

A host of new game-changing technology solutions is advancing the oil and gas industry's capabilities in deep and ultradeep waters.

Advances have been noted in technologies for deepwater drilling, floating production, subsea wells, deepwater pipeline construction and protection, risers, subsea separation, controls, tie-ins and tiebacks, flow assurance, and hub design, among others.

Even with the most innovative technology advances, however, it's important to keep in mind practical considerations in this hotly competitive market, according to Eric H. Namtvedt, president of FloaTEC.

"I am sure the deepwater challenges will continue to produce astonishing achievements," he says. "But, as we say at FloaTEC, with our unique support by our parent companies J. Ray McDermott and Keppel FELS, no concept or technical breakthrough has any real value unless it can be coupled with a credible and doable delivery model, where the elements of project deliveries are managed by capable contractors who can handle the risks of the complete supply chain."

Deepwater drilling/completion/intervention

Brian Skeels, emerging technology manager, FMC Technologies, ticks off these technology needs for deepwater drilling: "Dealing with deep well and deepwater kicks, especially when a deep well kick is undetectable until sometime later, as the kick is circulated out; accepting expandable casing for more of the well's casing strings—eventually getting closer to the monodiameter well concept; and continued efforts in slimbore-surface BOP drilling to help keep the rig size down."

Gary Shaw, technology leader, VetcoGray, a GE Oil & Gas business, notes that the technology solutions and innovations for deepwater drilling come primarily from time and weight savings, citing "time savings to cut rig and installation costs, and weight savings to extend the depth capabilities of older, less costly rigs and solutions such as TLPs. Recent examples in the drilling area would include the new drilling riser connector VetcoGray has developed, which runs in a fraction of the time of older designs, has high strength capabilities, and offers the added benefit of not requiring a person on the rig floor, making it inherently safer."

In the subsea completions arena, most of the game-changing equipment consists of the technologies needed to complete subsea processing systems, which includes equipment such as separators, pumps, compressors, and most importantly, the power equipment to make it all happen, says Shaw.

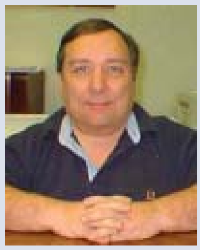
"Beyond equipment, new materials and coating technologies in areas like composite materials could have a significant impact," he says. Shaw also foresees needed improvements in the ability to access and control a large number of downhole functions through the subsea tubing hanger, tree, and associated installation tools.

Regarding subsea intelligent wells, one challenge is to be able to process and interpret the information in a timely manner, preferably in real time, contends Shaw: "Another key issue is the ability to maintain reliability of the complex devices, or provide an efficient method to mitigate [problems]."

But Skeels offers a caveat on the intelligent well solutions.

"Oil companies that favor intelligent wells feel they are 'designing out' the need for future interventions, citing intelligent wells as their ticket for low-cost changes to recomplete as the reservoir depletes," he says. "Others feel this is a foolhardy endeavor and should make some plans for easier, more cost-effective intervention into a well regardless of the well design."

> "I really like the idea of AUVs ferrying out ROVs to remote sub-ice fields, plugging into a power docking station, performing subsea interventions, then traveling back from under the ice."
>
> *— Brian Skeels, FMC Technologies*



Skeels says, "The debate will be determined by economics and how subsea wells behave as the global subsea well count ages and how quickly the service sector can respond to a 'sick' well."

Noting that new solutions in light well intervention will play a part in that scenario, Skeels notes the technique's growing popularity and contends it should be commonplace in all global deepwater theaters by 2010: "I really like the idea of AUVs ferrying out ROVs to remote sub-ice fields, plugging into a power docking station, performing subsea interventions, then traveling back from under the ice."

Control systems

Longer offsets imposed by subsea-to-beach scenarios, and the push for a "green" control system will influence future control system designs, predicts Skeels.

"Electro-hydraulic and electro-hydraulic-fiber optics will continue to be around for some time to come because of the greater mechanical power-to-size ratio that hydraulic systems will always be able to provide," he says. "However, all-electric systems will eventually come into their own for subsea fields beyond 10,000 ft water depths and/or subsea fields with a significant subsea separation/boosting infrastructure associated with it."

He also notes that there is little all-electric downhole equipment currently controlled by electrics: "Research is going on, but downhole temperatures above 300° F may limit its reliability."

Shaw looks for a reduction in production umbilical diameters, as the all-electric technology will remove the need for hydraulic lines in the umbilical.

Tie-ins and tiebacks

The clustered-well field architecture is here to stay, according to Skeels: "The question now is whether the flowline connection is horizontal or vertical, and how can one put an insulating jacket (dog house) around it afterwards to prevent heat loss when the rest of the manifold and pipeline is insulated."

As for long-distance tiebacks, they will "keep getting pushed longer and longer, but not without the assistance of subsea separation and boosting," Skeels says. "[Operations] under the arctic ice will hasten longer-offset technology."

Uri G. Nooteboom, vice-president, field development projects for INTEC, contends that continuing development and maturation of subsea processing and monitoring technologies (such as pumping, compression, separation, electric flowline heating, metering, etc.) will have a positive effect on industry efforts to extend long-distance tiebacks.

"Improvements in power delivery and control systems, both long-distance and in-field, will lead to improved economics," he says. "The evolution of operator views on project risk acceptance may also have an effect."

Non-hydraulic (electrical) controls systems will help improve the reliability and economic viability of long- distance tiebacks, Nooteboom adds.

Long tiebacks is an area of heightened focus for Vetco Gray, notes Shaw.

"We have just completed work on the Statoil Snovhit project in the Barents Sea, the first subsea-to-beach completion in the world," he points out. "The power and communications equipment was qualified and tested to an offset distance of 205 km, a new industry record."

Riser installations

In the case of drilling risers, Shaw thinks there are great opportunities in not only improving riser installation time, but also riser retrieval time.

"It is easy to relate to the economic savings associated with riser trip time in a fifth-generation rig with a hefty daily rate," he says. "There is, however, another driver for reducing riser trip time. In deep water it could take well over a day to trip out a 21-in. drilling riser. In the case of an unforeseen environmental condition, such as a rapidly strengthening hurricane, the contractor may not have a day or two to trip the riser out and move away from location. In certain events, it may be safer to ride out the hurricane with a connected riser than ride through a hurricane-force wind with half the riser hung off on the spider. The reduction of riser trip time, in some situations, could make the difference between one of the above two unattractive scenarios and one that permits full retrieval of the riser and relocation of the drilling vessel to safer waters."

Skeels notes that the debate over whether to use steel catenary risers vs. free-standing or tensioned vertical production risers will be decided by the materials and welding issues encountered while working in ultradeep waters.

Flow assurance

One of industry's knottiest challenges in the deepwater theater is that of flow assurance.

Nooteboom contends that current deepwater designs employ a considerable conservatism due to uncertainties in flow assurance strategies resulting from uncertain input data.

"This conservatism often results in increased [capital and operating expenditures] in the form of materials (e.g., insulation), chemicals, and back-up strategies to manage hydrates," he points out. "The operational systems put in place to manage hydrates during shutdown conditions (e.g., depressurization, dead oil circulation) and cold restart conditions, as well as to manage hydrate blockages if they occur, are operationally complex and can dictate the entire development architecture."

A cost-effective and proven-reliable electrically heated flowline (EHF) system could change all this, Nooteboom says: "Knowing that an EHF system could be run continuously or switched on during an unplanned shutdown or restart, if a hydrate blockage occurred, would eliminate the capex, opex, and operational complexities associated with conservative 'belt-and-suspenders' solutions."

Further down the line is the concept of cold flow, a notion that has been much discussed of late in the flow assurance community, Nooteboom points out.

"The typical flow assurance approach is to preserve the heat energy in the fluids to prevent wax deposition and hydrate formation," he explains. " Cold flow would allow the fluids to cool such that wax and hydrate particles are allowed to form and are transported to a host as a slurry without forming blockages. This technology does not currently exist.

"The ability to employ cold flow in deepwater and/or long distance tiebacks has the potential to save significant costs and operational complexity in the form of eliminating insulation, reducing or eliminating chemical use, and decreasing operational complexity.

In the end, subsea processing facilities themselves are flow assurance solutions in that "by separating phases, hydrate formation becomes reactant-limited, while cold flow solutions become enabled for the hydrocarbon liquids and direct water disposal is a possibility," says Shaw. "Otherwise solutions, such as VetcoGray's HeatBank, can be expanded to items beyond coldspots, valves, and connectors."

Shaw adds, "As a driver for e-field options, flow assurance software can be used to stabilize unstable operating conditions, provide needed input to condition monitoring software, and otherwise provide options for reduced risk while operating at, or near, minimum safe operating conditions."

Nooteboom concurs, adding that subsea processing technology has made great gains in the past decade, and the pace of advancement is increasing: "Advancements in the capabilities of subsea processing, pumping, and compression are changing the way we look at flow assurance for subsea developments and will help to increase technically viable tieback distances to economically develop remote oil reservoirs."

Boosting/pumping

Another area of game-changing technology advances in deepwater operations is that of subsea boosting and pumping.

"Continuing development, application, and maturation of subsea separation systems technologies will allow installation of subsea pumping/compression systems that are more compact, more efficient, and better able to accommodate changing GVF over field life," Nooteboom says. "Improvements in power delivery and control systems, both long-distance and local field, will lead to improved economics."

Flexible solutions and power are the critical issues in subsea boosting, according to Shaw.

"The operating envelopes for many fields are large—high production early in life and low production late in life," he notes. "Finding solutions—for instance, changing out of equipment and/or operating with varying redundancy to effectively produce throughout the life of the fields—is one key factor to facilitate field development and/or improve the economics.

"Power is also a limiting factor. The demand for both higher power and longer step-outs is increasing. Higher power might reduce the number of pumps running in series or parallel and a subsea VSD and distribution system might increase the step-out distance."

The big challenge in multiphase pumping is high differential pressure, says Shaw: "Low reservoir pressure, in combination with deepwater installation, demands high delta pressure. By being able to supply high delta pressure, running pumps in series can be avoided."

In the end, Skeels thinks that multiphase pumping will stay a niche market, "because customizing a pump/impeller system for every GOR will be one-of-a-kind designs for each project. Accurate, 'fiscal-quality' multiphase metering also still has a ways to go but is making great strides and, hopefully, it will eventually eliminate the need for a test pipeline."

Subsea compression

Subsea compression is considered to have a significantly lower investment and operational cost than the platform compression alternative, with the same core functionality of compressing gas for transportation purposes to shore for further processing and export, contends Shaw, adding, "In a nutshell, subsea compression has the potential to increase the ultimate gas recovery."

Working with Aker Kvaerner, GE Oil & Gas has completed the conceptual design of a 12-Mw subsea compressor, the Blue-C™, the largest ever developed for subsea applications, and is set to begin construction of the compressor to be tested in the pilot project in Ormen Lange field off central Norway.

> "The aim of the [Ormen Lange] pilot project is to evaluate whether a subsea compression station, at approximately 900 m of water depth, is a viable alternative to an offshore platform.... This technology could then be applied to other subsea field developments, eliminating the need for offshore platforms."
>
> *— Gary Shaw, GE Oil & Gas Vetco Gray*

"The aim of the pilot project is to evaluate whether a subsea compression station, at approximately 900 m of water depth, is a viable alternative to an offshore platform," Shaw says. "This project represents a major milestone in the development of subsea compression technology. If the project produces the expected results, the Ormen Lange partners will have a cost-effective alternative to the originally planned offshore platform. This technology could then be applied to other subsea field developments, eliminating the need for offshore platforms."

Subject to the Ormen Lange partners' final approval, Aker Kvaerner's subsea compression station pilot project will undergo controlled endurance tests during 2009-2011 at a gas treatment facility in Nyhamna, Norway.

Deepwater pipelines

Construction methods for deepwater pipelines have logged significant progress, but line pipe materials issues still need to be resolved.

"J-lay is well established," contends Skeels. "The question is back to the pipe design, its mill quality, and the efficacy of its fabrication in the field.

"I think we're coming to a point where it's the fabrication methods and the material that we have to design in for the pipeline itself, not the installation vessel. Wall thicknesses are getting too great for pipe mills to handle with consistent quality, and conventional weld approaches are becoming more and more suspect, requiring difficult pre- and post-heat treatment, not to mention understanding the complicated weld metallurgy involved. Welding rod material and welding procedures are being taxed to their theoretical limits. Insulation and insulation integrity (not cracking or absorbing water) is becoming a growing concern as subsea facilities continue to move farther out in 40° water. HIPPS [high-integrity pipeline protection system] will also play a big part in keeping riser material choice and wall thickness to reasonable limits."

With water depths getting deeper and deeper, pipeline infrastructure has also had to change to accommodate harsher environments, according to Shaw.

"For example, wall thickness has increased to handle the ultra-high pressures," he points out. "This has, in turn, posed a challenge for offshore pipeline inspection service capabilities, as many conventional in-line tools are no longer up to the task."

Hub design

Nooteboom sees a long-term advantage for deepwater hubs.

"As declining reservoirs will create excess capacity on existing facilities, (long-distance) tiebacks will allow remote reserves to be economically produced to these existing facilities," he says. "This will, on one hand, extend the economic lifespan of the existing (hub) facilities and, on the other hand, bring the development cost of remote deepwater reservoirs within economic reach.

"Where such hub facilities don't exist and the development of a small reservoir with a standalone production facility is not economically viable, an economic solution may be found by developing several smaller remote reservoirs concurrently and producing them to a common new-built hub. Several operators may collaborate and collectively develop their respective reservoirs as tiebacks to a jointly owned hub or encourage a third party to build and operate this facility. Independence Hub, in Mississippi Canyon Block 920, is an example of such a joint development among Anadarko, Kerr-McGee [now part of Anadarko], Dominion, Spinnaker, Devon, and Enterprise.

"We are likely to see more of these collaborative developments with jointly owned/operated hub infrastructure; or where third parties develop hub facilities to accommodate multiple operators where these operators would otherwise not have been able to economically produce their reservoirs as standalone developments."

Subsea hubs also will be designed for retrofit of subsea separation, pumping, and compression modules, as needed to suit changing production scenarios.]

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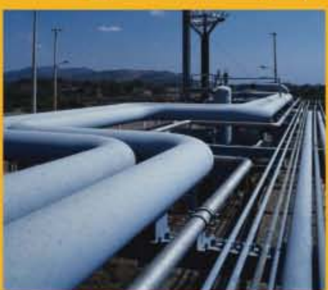

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