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Midyear Forecast

Uruguay to review offers for two blocks
Industry sees price breaks as contracts renegotiated
Low CO_2 slip in HP MDEA systems investigated
Study helps model buried pipeline pitting corrosion

OIL&GAS JOURNAL®

July 20, 2009
Volume 107.27

MIDYEAR FORECAST

REGULAR FEATURES

COVER

Marathon Oil Corp. operates this refinery in Robinson, Ill., and holds 320,000 net acres in the Bakken shale oil play in North Dakota, pictured on p. 20, where production started in 2006. The sluggish US economy will suppress oil demand for the remainder of 2009. OGJ's Midyear Forecast special report details the slide in demand for oil, gas, and most other energy sources and takes a look at this year's worldwide oil market. Photos courtesy of Marathon.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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DOBROWSKI L.L.P.
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Take Nothing Judgment
in favor of its clients
Diamond Offshore Co. & Diamond Offshore (Trinidad)
in

Pioneer Natural Resources USA, Inc., Marathon Oil Company, Nippon Oil Exploration U.S.A. Limited, Total E&P USA, Inc., BP Exploration & Production, Inc. and Marubeni Oil & Gas (USA), Inc.
v.
Diamond Offshore Company and Diamond Offshore (Trinidad) L.L.C.

Civil Action No. 05-0224,
United States District Court for the Eastern District of Louisiana,
Hon. Daniel E. Knowles III presiding

Two week bench trial

Damages sought by Plaintiffs: $100 million

No liability found for alleged allision between
Diamond's MODU *Ocean America*
and Plaintiffs' Canyon Express Pipeline System
during Hurricane Ivan.

Diamond's In-House Legal Counsel
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Terence W. Waldorf
Laura P. Haley

Dobrowski L.L.P.
Paul J. Dobrowski
Lee M. Larkin
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Robert Guidry
(New Orleans, LA)

OGJ Newsletter

July 20, 2009

International news for oil and gas professionals
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General Interest — Quick Takes

Oil sands investment to recover by yearend

The expected economic recovery in developing the oil sands in Alberta may start in late 2009 or early 2010, said Robert J. Mason, managing director, head of oil sands, investment banking, global energy, and power group, TD Securities Inc., Calgary.

"Some producers are thinking about restarting projects because oil price forecasts are more definite," Mason said, speaking July 14 at PennWell Corp.'s Oil Sands & Heavy Oil Technologies Conference & Exhibition in Calgary. He added that capital cost have come down by 30% in the last 9 months.

Projects he thought might be slow in restarting are those involving upgraders. Upgrader projects are still in question with some deferred and others canceled, he said.

Mason noted that since fall of 2008, development activity has been in a "pause and evaluate" mode because of low oil prices, lack of available financing, high borrowing costs, and inability of small companies to raise capital.

One higher cost the companies will have to contend with is the cost for handling carbon emissions. He said in past years, companies had expected this cost to add 25-30¢/bbl but now additional costs of $2-3/bbl are more likely.

Labor forecasts have also come down. He noted that projections are that new projects will need 25,000-28,000 fewer workers if the pace of development is as slow as now expected.

Investor convicted in scheme targeting SOCAR

A federal jury in Manhattan convicted a US investor on July 10 of trying to bribe senior government officials in Azerbaijan in a scheme to privatize the country's national oil company in a rigged auction, the US Department of Justice said.

Frederic A. Bourke Jr. of Greenwich, Conn., conspired with Czech investor Viktor Kozeny and members of their consortium to make a massive profit on the auction using options and vouchers to bid for shares of the State Oil Co. of the Azerbaijan Republic (SOCAR), DOJ said.

DOJ said evidence presented during the 6-week trial showed that the group flew millions of dollars in cash into the country for Oily Rock Ltd., a company which Kozeny allegedly controlled, to buy the options and vouchers.

Bourke, a neighbor of Kozeny's in Aspen, Colo., invested about $8 million in Oily Rock for family members and friends as well as on his own behalf, DOJ said. Evidence also showed that Bourke obtained directorships, salary, and stock options with other companies Kozeny allegedly set up and funded, DOJ said.

DOJ said that starting in August 1997 through the fall of 1998, Bourke and others conspired to pay or cause to be paid millions of dollars in bribes to Azeri government officials. In return, the government officials were to ensure that the Bourke-Kozeny investment consortium would gain, in secret partnership with the Azeri officials, a controlling interest in SOCAR and its substantial oil reserves.

Bourke also arranged for two of the corrupt officials to travel to New York City on different occasions in 1998 to receive medical treatment, for which Oily Rock paid, according to DOJ. Thereafter, in interviews with the Federal Bureau of Investigation in April-May 2002, Bourke falsely stated that he was not aware that Kozeny had made the alleged payments to the Azeri officials, it said. DOJ indicted the two men in October 2005.

The jury convicted Bourke of conspiracy to violate the US Foreign Corrupt Practices Act and the Travel Act, and of lying to the FBI. It acquitted him of a money laundering charge. At sentencing, which is scheduled for Oct. 13, Bourke faces up to 5 years in prison and a $250,000 fine for each of the two charges on which he was convicted.

BLM Colorado to hold its first on line lease sale

The US Bureau of Land Management's Colorado state office posted a proposed list of parcels on July 13 for what will be the agency's first on line oil and gas lease sale.

Congress directed the US Department of the Interior agency to conduct an online lease sale as part of DOI's fiscal 2008 budget as a one-time event to determine whether it is feasible, BLM said. It selected Colorado for the event, which will be held entirely on line and run from 9 a.m. on Sept. 9 to noon on Sept. 17.

The auction pilot's web site is at www.blm.gov/leasingpilot. It lists 38 parcels totaling 28,489 acres. BLM said the parcels will be split into two groups and become available for bids on a staggered basis over 2 days, with each group being offered for 7 days.

Similar to typical on line auctions, bidders will have the option of submitting one-time set bids on parcels and proxy bids, which automatically increase to a set amount indicated by the bidder, according to BLM.

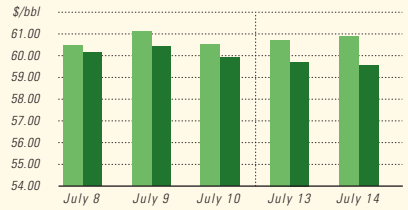
It said bidders would have to register online to actually bid and encouraged them to do so early to become familiar with the web site and the auction guidelines.

Credit card information and a sworn statement of an intention to buy are required. An on line tutorial is available at the web site, which will remain available for viewing for 30 days after the sale closes.

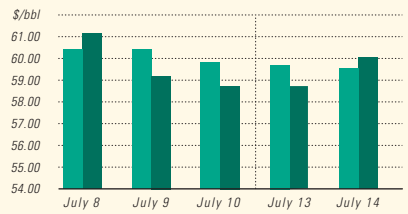
There will be no charge for filing protests, BLM said. Protests of parcels being offered must be in writing and delivered by hand, mail, or fax. BLM has not made any provision for filing protests on line or by e-mail. ✦

Industry Scoreboard

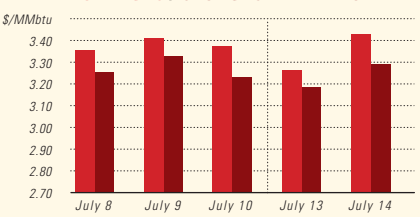
IPE BRENT / NYMEX LIGHT SWEET CRUDE



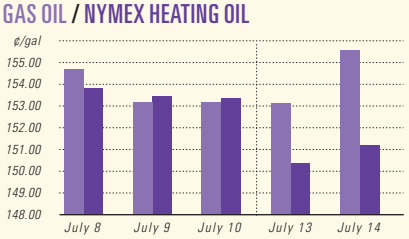
WTI CUSHING / BRENT SPOT



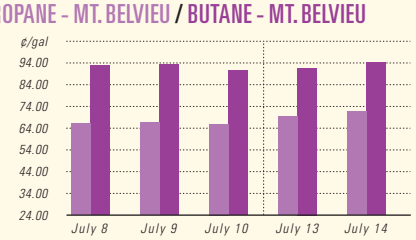
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



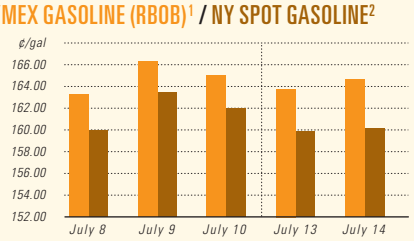
IPE GAS OIL / NYMEX HEATING OIL



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.

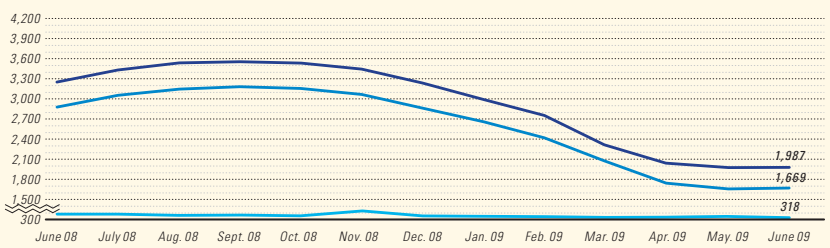
US INDUSTRY SCOREBOARD — 7/20

Latest week 7/3	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	9,191	9,071	1.3	8,950	9,023	–0.8
Distillate	3,266	3,724	–12.3	3,674	4,057	–9.4
Jet fuel	1,376	1,586	–13.2	1,384	1,560	–11.3
Residual	661	688	–3.9	606	639	–5.2
Other products	3,891	4,474	–13.0	3,994	4,498	–11.2
TOTAL DEMAND	18,385	19,543	–5.9	18,608	19,777	–5.9
Supply, 1,000 b/d						
Crude production	5,216	5,109	2.1	5,254	5,130	2.4
NGL production[2]	1,931	2,297	–15.9	1,882	2,245	–16.2
Crude imports	9,227	10,002	–7.7	9,289	9,789	–5.1
Product imports	2,651	3,344	–20.7	2,890	3,220	–10.2
Other supply[3]	1,759	1,358	29.5	1,692	1,400	20.9
TOTAL SUPPLY	20,784	22,110	-6.0	21,007	21,784	–3.6
Refining, 1,000 b/d						
Crude runs to stills	14,413	15,010	–4.0	14,413	14,934	–3.5
Input to crude stills	14,765	15,753	–6.3	14,765	15,266	–3.3
% utilization	83.7	89.4	—	83.7	86.8	—

Latest week 7/3	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	347,297	350,193	–2,896	293,936	53,361	18.2
Motor gasoline	213,140	211,238	1,902	211,766	1,374	0.6
Distillate	158,738	154,999	3,739	122,501	36,237	29.6
Jet fuel–kerosine	42,839	41,872	967	38,764	4,075	10.5
Residual	36,582	37,265	–683	39,366	–2,784	–7.1
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.3	23.6	–1.3	19.1	22.0	
Motor gasoline	23.2	23.0	0.9	22.7	2.2	
Distillate	48.6	45.6	6.6	29.4	65.3	
Propane	77.5	76.2	1.7	45.9	68.8	
Futures prices[5] **7/10**			Change		Change	%
Light sweet crude ($/bbl)	61.48	69.36	–7.88	142.46	–80.98	–56.8
Natural gas, $/MMbtu	3.41	3.80	–0.39	13.46	–10.05	–74.7

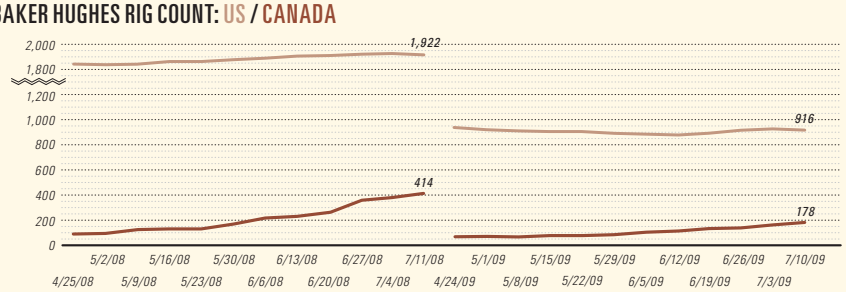
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Exploration & Development — *Quick Takes*

Three Forks rates rise as drilling costs fall

Operators are climbing the learning curve in the Williston basin by drilling long lateral wells in the Bakken and Three Forks formations with as many as 24 frac stages.

One operator, Brigham Exploration Co., Austin, Tex., said it is continuing to see drilling and completion costs fall.

Initial rate at the Strobeck 27-34, in the Ross area of Mountrail County, ND, is 1,788 b/d of oil and 1.4 MMcfd of gas from a long lateral in Three Forks. Brigham Exploration completed the well with 20 frac stimulation stages, 18 of which were effective.

Strobeck 27-34, which appears to have had the basin's second highest initial rate for a Three Forks completion, cost $3.9 million, 33% lower than company late 2008 authority for expenditures at similar wells.

"The Strobeck 27-34 results also confirm the core taken from our Anderson 28-33, which indicated that both the upper Three Forks and middle Bakken formations were heavily saturated with oil," the company said.

Anderson is 1 mile west of Strobeck and about a mile southwest of Brigham Exploration's Carkuff-22 1H, which went on production at 1,110 b/d of oil after 12 frac stages in a short lateral.

The company recently drilled the lateral of its Anderson 28-33 on a 1,280-acre unit in the Ross area to 19,900 ft in the Bakken and ran 24 swell packers to bottom. A 24-stage frac operation, believed to be a record number for the basin, is planned in early August.

Brigham Exploration has spud the Brad Olson-1H 9-16 well in the Rough Rider area of Williams County, ND, and plans 24 frac stages in an intended 20,000-ft Bakken lateral at an estimated cost of $6.25 million, 34% less than 2008 AFEs.

Brigham Exploration controls 35,200 net acres in the Ross area and 100,345 net acres in the Rough Rider area. It is participating in 20 Mountrail County Bakken wells operated by others in various stages, including 12 already on production.

Haynesville well results encourage operators

Forest Oil Corp., Denver, and Goodrich Petroleum Corp., Houston, reported results from recent Jurassic Haynesville horizontal well completions in Louisiana and East Texas.

Forest, meanwhile, said it operated only four rigs in this year's second quarter and continues to defer significant investments until drilling and completion costs are reduced to acceptable levels to support a larger drilling program at current natural gas prices.

In Red River Parish, La., the Driver 13-1H well produced into a sales line at 20.3 MMcfd of gas equivalent with 6,500 psi flowing casing pressure in early July. It had 10 frac stages in a 3,500-ft horizontal leg and cost $9 million.

Forest has identified 110 potential horizontal locations on the 11,050 Haynesville prospective net acres it holds in Louisiana. It will maintain a one-rig program in the parish for the rest of 2009 and one rig in other prospective areas of the play in Texas and Louisiana.

Goodrich Petroleum said the Taylor Sealey-3H in Panola County, Tex., produced at 9.3 MMcfd with 5,200 psi on a $^{24}/_{64}$-in. choke. It is in Minden field 6 miles south of the Lutheran Church-5H well that had an initial rate of 9 MMcfd. The company has 100% working interest.

The company reached total depth at two other Haynesville shale horizontal wells, T. Swiley-4H in Minden field and Beard Taylor-1H in Beckville field.

Goodrich Petroleum also held interests in three wells completed by Chesapeake Energy Corp. in Bethany-Longstreet field, Caddo and DeSoto Parishes, La.

Initial rates were 12.5 MMcfd with 7,800 psi on an $^{18}/_{64}$-in. choke at Johnson 32H-1, Goodrich 31%; 15.4 MMcfd with 6,100 psi on a $^{22}/_{64}$-in. choke at Wallace 36H-1, Goodrich 22%; and 14 MMcfd with 4,000 psi on a $^{22}/_{64}$-in. choke at the Bryan 25H-1, Goodrich 13%.

Alberta's Nikanassin zone has resource play

Daylight Resources Trust, Calgary, said it is working on a strategy to develop a gas resource play in the Jurassic Nikanassin zone just below Cretaceous Cadomin at Elmworth in the Alberta Deep Basin.

Two vertical wells in the first quarter found more than 100 m of sand in the Nikanassin at 2,700-3,200 m and came on production in March and April at initial rates of 2-3 MMcfd of gas.

Daylight Resources plans to drill one more vertical delineation well and a horizontal well before the end of the 2009-10 winter drilling season. It holds Nikanassin rights in more than 51,200 acres at Elmworth.

The company said it is investigating the potential for using the same advanced horizontal drilling and multistage fracturing technologies on the Nikanassin that it has applied in the Cadomin.

Due to weak natural gas prices, Daylight Resources has deferred the majority of its planned gas expenditures for the 2009 second quarter and early third quarter to late third quarter and fourth quarter.

US nets $700 million for GOM leases

The US Department of the Interior's Minerals Management Service said it accepted high bids valued at $700 million and awarded 328 leases to the successful high bidders who participated in the Central Gulf of Mexico Oil and Gas Lease Sale 208.

MMS said funds from the total high bids will be distributed to the general fund of the US Treasury, shared with the affected states, and set aside for special uses that benefit all fifty states.

It said the leases were awarded following the completion of an extensive, two-phase bid evaluation process to ensure that the Federal government receives a fair monetary return for the public mineral resources it makes available.

Seventy companies submitted 476 bids on 348 tracts in the sale, held on Mar. 18. The total for high bids submitted on all tracts was $703,048,523. Using the bid evaluation process, MMS rejected high bids totaling $12,673,983 on 19 tracts as insufficient for fair market value.

In addition, MMS said that a successful high bidder forfeited the lease and the ⅓th bonus which was submitted with the bid. As a

result, $52,836.40 of the $264,182 bid on the forfeited tract has been collected.

The highest bid accepted on a tract was $65,611,235 submitted by Shell Gulf of Mexico Inc. for Mississippi Canyon Block 721. This tract lies in 800-1,600 m of water and received two bids.

The top five companies with the highest number of accepted high bids for Sale 208 were Shell Gulf of Mexico Inc., 39 for $154 million; BHP Billiton Petroleum (Deepwater) Inc., 28 for $50 million; BP Exploration & Production Inc., 25 for $77 million; Ecopetrol America Inc., 22 for $19 million; and Noble Energy Inc., 22 for $54 million. ✦

Drilling & Production — *Quick Takes*

Murphy starts producing Thunder Hawk field

Murphy Oil Corp. has started producing oil and associated gas from Thunder Hawk field on Mississippi Canyon Block 734 in the Gulf of Mexico. The field lies in more than 5,700 ft of water, about 145 miles southeast of New Orleans.

The facilities on the semisubmersible floating production unit have a capacity to handle 45,000 bo/d and 70 MMscfd of gas.

Initial production is from three subsea completed wells tied back with flowlines to the semisubmersible.

Operator Murphy has a 37.5% interest in Thunder Hawk. Partners are Eni Petroleum US LLC 25%, Statoil Hydro USA E&P Inc. 25%, and Marubeni Oil & Gas USA Inc. 12.5%.

Apache lets contract for Forties oil platforms

Apache North Sea Ltd. has contracted Petrofac Ltd. for the onshore engineering and offshore construction that will support the five fixed platforms in Forties oil field in the UK North Sea.

The deal is worth £25 million/year and it will last 3 years with Apache holding two optional 1-year extensions.

Forties field is producing more than 70,000 b/d of oil and Apache has spent more than $1.2 billion on the mature assets since its acquisition in 2003. Apache is confident that Forties could produce oil for another 20 years and has identified 60 targets ranging in size from less than 0.5 MMboe to 1.5 MMboe to drill; most of the prospects are less than 1 MMboe.

In June, Apache started oil production from its Forties Charlie 6-3 well with 10,500 b/d (OGJ Online, June 22, 2009). The well is the seventh development well brought on production at Forties this year. The well's initial production rate is the field's highest since 1994, Apache said.

US drilling count drops

After climbing for 3 consecutive weeks for the first time since early September, US drilling is down by 12 units to 916 rotary rigs working the week ended July 10, Baker Hughes Inc. reported.

That compares with 1,922 rigs drilling in the US during the same period a year ago.

Land operations led the latest loss, down 7 rigs to 871 drilling. Offshore drilling declined by 5 rigs to 37, all in the Gulf of Mexico. Drilling in inland waters was unchanged with 8 units drilling.

Of the rigs still working, those drilling for oil increased by 5 to 234. Those drilling for natural gas declined by 16 to 672. There were 10 rigs unclassified. Horizontal drilling decreased by 6 rigs to 390. Directional drilling increased 4 to 165.

Among major producing states, Louisiana was down 4 rigs to 130 drilling. California dropped 3 to 20. Texas and New Mexico were down 2 each to 336 and 38, respectively. Wyoming was down 1 rig to 30; Alaska was down 1 to 5. States with unchanged rig counts included Oklahoma, 82; Colorado, 45; and North Dakota, 40. Arkansas's rig count increased by 1 to 45.

In other states of interest, Pennsylvania, West Virginia, and Utah were unchanged with respective rig counts of 43, 20, and 16.

Canada's rig count increased by 13 to 178, down sharply from 414 rigs working in the same week in 2008.

Imperial lets contract for Kearl oil sands project

Imperial Oil Ltd. awarded Fluor Corp. a $1.5 billion engineering, procurement, and construction contract for infrastructure and offlease facilities for the first phase of the Kearl oil sands project, a surface mining and bitumen extraction operation about 70 km northeast of Fort McMurray, Alta.

Imperial expects the first phase to start producing in late 2012 at an average 110,000 b/d of bitumen.

In May, Imperial Oil said it was reactivating the $8 billion (Can.) Kearl project (OGJ Online, May 29, 2009). ✦

Processing — *Quick Takes*

Ukraine refinery hydrotreaters due revamp

JSC Ukrtatnafta has let contract to CRI/Criterion Catalyst Co. Ltd. and Shell Global Solutions Eastern Europe BV for a revamp of two processing units at its 360,000-b/d refinery in Kremenchug, Ukraine.

The work includes Shell reactor internals and a Criterion catalyst system for diesel hydrotreaters.

One of the revamped units will produce vacuum gas oil with less than 0.2 wt % sulfur. The other will allow the refinery to produce automotive diesel with sulfur content of less than 350 ppm and batches of diesel with sulfur content below 50 ppm.

Jubail hydrocracker, cat cracker, coker work let

Saudi Aramco Total Refining & Petrochemical Co. has let a contract to Technip for two packages, including one covering hydrocracking and catalytic cracking units, for the 400,000 b/d export refinery it will build in Jubail, Saudi Arabia.

The Aramco-Total venture let an engineering, procurement, and construction contract to Chiyoda Corp. and Samsung Engineering for a coker unit at the 400,000-b/d export refinery to be built in Jubail, Saudi Arabia.

Technip will handle engineering, procurement, and construction for the hydrocracking and catalytic cracking units and for

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some of the utility units and interconnecting network and process control system for the entire refinery.

The coker contract is one of 13 process packages for which the joint venture approved an awarding plan in June after a delay last year during which Aramco assessed projects in light of global economic problems (OGJ, June 22, 2009, Newsletter).

Aramco and Total formed the joint venture in third quarter 2008. Aramco holds 62.5% and Total, 37.5%. Aramco plans to offer 25% of the joint venture to the Saudi public out of its share in an initial public offering in the last quarter of 2010.

Venezuela acquires stake in Dominican refinery

The Dominican Republic, struggling to pay off oil debts to Venezuela, agreed to transfer a 49% stake in its 34,000-b/d, state-owned Refineria Dominicana de Petroleo SA (Refidomsa) to Venezuela's state oil company Petroleos de Venezuela SA.

The Dominican Republic has owned 100% of the refinery since last December, when it bought the 50% stake formerly held by Royal Dutch Shell PLC for $110 million.

Reports say the Shell sale was part of the firm's strategy to exit all of its businesses in the Caribbean in order to focus on other regions of the world.

The sale of the 50% stake in the refinery, which began operating in the mid-1970s, coincided with a visit to the Dominican Republic by Venezuelan officials, led by PDVSA commercial director Ramon Herrera.

The Venezuelans were in the Dominican Republic for talks on how the island nation could use goods and services to pay off $1 billion in debt to Venezuela for oil supplied under the Petrocaribe initiative.

The Dominican Republic is one of 18 Central American and Caribbean nations that participate in the PetroCaribe energy initiative under which Venezuela offers its crude and refined products to buyers on favorable terms.

The Herrera-led delegation discussed matters with Dominican Finance Minister Vicente Bengoa. The Dominican Republic currently receives 33,000 b/d of Venezuelan oil under the Petrocaribe initiative but wants an increase to 50,000 b/d.

In June of this year, Bengoa announced a plan for the repayment if its $1 billion oil debt, saying the bill would be "partially" settled with black beans and tourist packages—among other goods and services.

Bengoa said PDVSA would acquire its 49% share of the refinery by foregoing 60% of the payment it normally receives from the Dominican Republic for PetroCaribe oil over a 3-month period—about $130 million.

Venezuela's Energy and Oil Minister Rafael Ramirez said his country's plan is eventually to integrate the Dominican refinery into a network of eight refineries in various countries that are being upgraded or built by Venezuela as part of its PetroCaribe initiative. ✦

Transportation — *Quick Takes*

Chevron Australia awards construction contract

Chevron Australia Pty. Ltd. has awarded a $500 million (Aus.) contract to Thiess Pty. Ltd. for site preparation and construction of temporary facilities for the proposed 3-train LNG and domestic gas Gordon Project on Barrow Island off Western Australia.

The project will be supplied from the Greater Gorgon gas fields, including Jansz and Io.

Theiss is in a joint venture with Decmil Group Ltd. and Kentz Corp. Ltd. that in June was awarded another $500 million (Aus.) contract to design and construct an accommodation village capable of housing 3,300 people on the island.

Project scope for the new contract includes preparation of finished earthwork levels for the LNG plant and associated storage tanks, along with production of road base material and feedstock for concrete aggregate production. It also includes reticulation of site services, a material offloading facilities causeway and breakwater plus temporary construction facilities to be used by other contractors later.

The offshore gas fields will be developed via subsea wells and two pipelines bringing gas to Barrow Island where three LNG trains will each produce 5 million tonnes/year. There will also be a 300-terajoule/day domestic gas plant feeding into a pipeline to the mainland and a carbon dioxide sequestration plant with capability of storing the high levels of carbon dioxide contained in the Gorgon field in deep formations beneath the island.

Chevron has 50% of the project while ExxonMobil Corp. and Royal Dutch Shell PLC have 25% each.

BLM schedules times to discuss Ruby Pipeline

The US Bureau of Land Management will host seven public meetings during July to discuss a proposed natural gas pipeline that would extend from southwestern Wyoming across Utah and Nevada and into Oregon.

Meetings are scheduled July 21 in Malin, Ore.; July 22 in Lakeview, Ore.; July 23 in Winnemucca, Nev.; July 27 in Brigham City, Utah; July 28 in Elko, Nev.; July 29 in Kemmerer, Wyo.; and July 30 in Hyrum, Utah. All meetings will begin at 7 p.m.

The Federal Energy Regulatory Commission published a draft environmental impact statement on June 19 for the proposed 675-mile pipeline, which would have an initial design capacity of as much as 1.5 bcfd. Ruby Pipeline LLC, an El Paso Corp. subsidiary, is the sponsor. FERC will accept comments on the draft EIS through Aug. 10.

BLM said the federal Mineral Leasing Act makes it responsible for issuing rights-of-way on public lands. It said it is working with the US Bureau of Reclamation, the US Fish and Wildlife Service, the US Forest Service, the US Conservation Service, the US Army Corps of Engineers, the Utah Public Lands Policy Coordination Office, and the Lincoln County, Wyo., Board of County Commissioners.

Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposed project and participate in the analysis under the National Environmental Policy Act, BLM said. ✦

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

2009

AUGUST

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

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

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

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

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

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

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

SEPTEMBER

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

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

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

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

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

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

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

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

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

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

✦Multiphase User Roundtable-Mexico, Villahermosa, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-mexico.org. 22-23.

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

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

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

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

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

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

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

OCTOBER

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

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

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

The ethanol question

Sam Fletcher
Senior Writer

Exports of anhydrous ethanol from Brazil to the US dropped to only 22.3 million l. in the 3 months through June, compared with 376.2 million l. shipped to the US in the same period last year.

"The reduction in direct exports to the US has been offset by a large increase in exports to India, Japan, and South Korea," said the Brazilian Sugarcane Industry Association. The group gave no other reason for the fall of US exports in their latest report. Ethanol exports since the beginning of the harvest totaled 985 million l., down from 1.1 billion l. in the same period last year. Exports to Caribbean countries and to Europe remained at about the same levels as last year, officials said.

June rains reduced the number of days for harvesting and crushing cane in south-central Brazil, impacting production of anhydrous ethanol. Ethanol production in the second half of June reached 1.424 billion l., 8.2% below the same period last year in the region. That included 359 million l. of anhydrous ethanol and 1.065 billion l. of hydrous ethanol. "From the beginning of this harvest to the end of June, anhydrous ethanol production in south-central Brazil totaled 1.532 billion l., down 23.84% from the same period a year before," said the sugarcane association. Hydrous ethanol, used to fuel Brazil's rapidly expanding fleet of flex-fuel vehicles, reached 5.95 billion l., up 40.29% from the same period in last year's harvest.

Demand for anhydrous ethanol has been stable in the Brazilian market this year, despite increased sales of flex-fuel cars, officials said. Sales of hydrous ethanol increased 25% in April-June from the same period a year before, with shipments by producing mills totaling 1.92 billion l., up 1.5% from May, said officials.

Brazil is the world's largest producer of sugarcane, the second-largest ethanol producer behind the US, and one of the biggest consumers of ethanol. Its expanding flex-fuel vehicle fleet now accounts for more than a third of the country's entire light-vehicle fleet.

Despite a slight increase in prices paid to producers, ethanol is still priced below production costs in the Brazilian market. As a result, the price of ethanol at the pump is competitive with that of gasoline, unlike the situation in the US.

Kia considers alternatives

Meanwhile, despite the push for alternative fuels, there are yet no diesel, no electric, and no hybrid cars on the US showroom floors for Kia and Subaru, two of the only three auto brands to increase sales this year when bigger companies have trouble attracting customers, according to Carlist.com online newsletter.

That doesn't necessarily amount to a rejection of alternative fuels. Michael Sprague, vice-president of marketing for Kia USA, said his company's success during the economic downturn is the result of "focus" and heavy advertising.

"We're looking at diesels and turbos and hybrids and LPGs and all those things because we recognize there is a desire for those things here," said Sprague in a video interview on the web site. "We do have a lot of those things available in other parts of the world."

As for Kia's interest in alternate fuels, Sprague said, "Hydrogen is probably too far out simply because we don't have the infrastructure here in the US. From my perspective, the government has to set the course there."

He said, "Electric cars are mostly for consumers who want a commuter vehicle, but again there is the problem of infrastructure." Sprague said, "If you're driving the vehicle, how are you going to get it charged? If you're in a town or municipality are they going to allow you to plug it and get it charged?"

Meanwhile, he said, other manufacturers who have brought hybrids to the US "are doing very well."

In the US market, Sprague said, "Diesel still seems to be somewhat of a niche. A lot of it is just about people not understanding diesel technology."

In Europe, of course, diesel "is very common and less expensive than traditional petrol," said Sprague. Such markets make a diesel model "almost a cost of entry" for a car manufacturer.

For Kia to bring its diesel vehicles into the US, Sprague said, "There are a lot of US regulations, and the company would have to ameliorate its diesel engines to meet the very strict US requirements." ✦

The Arab Republic of Egypt

Ministry of Petroleum

The Egyptian General Petroleum Corporation (EGPC)

Ganoub El Wadi Petroleum Holding Company (Ganope)

Announcement

For

The International Bid Round-1/2009

The Egyptian General Petroleum Corporation (EGPC) and Ganoub El Wadi Petroleum Holding Company (Ganope) invite specialized companies in Oil and Gas exploration and exploitation for the First International Bid Round-1/2009 including eleven (11) blocks in the Gulf of Suez (GOS) and the Eastern Desert (E. Desert), as shown in the following table and in accordance with the production sharing agreements model applied in the Arab Republic of Egypt.

Block No.	Block Name	Area Km^2	Province
EGPC blocks			
1	West Darag Offshore	254.4+178.7	GOS
2	South Darag	259.3	GOS
3	Northwest Abu Zenima	276.3	GOS
4	East Ras Budran Offshore	45.56	GOS
5	Northeast Issran	343	GOS
6	Northeast Morgan	63.114	GOS
7	Northeast Amal	27.92	GOS
8	North Ras El Ush	164.5	GOS
Ganope blocks			
9	West Wadi Dib	506	E. Desert
10	Wadi Abu Had	258	E. Desert
11	West Tawila	88	S. GOS

Data required for blocks (1 to 8) are available at the Information Center, Nasr City

1A Ahmed El Zomor St., Nasr City, Cairo – Egypt

Data required for blocks (9 to 11) are available at Ganoub El Wadi Petroleum Holding Company Headquarter.

19 Mostafa Refaat St., Sheraton residence – Heliopolis - Cairo – Egypt.

Purchasing the data package for each block is a pre requisite to bid for the block.

The basic data, coordinates, procedures and conditions for participation in this Bid Round can be obtained through The Egyptian General Petroleum Corporation website www.egpc.com.eg and through Ganoub El Wadi Petroleum Holding Company website www.Ganope.com

The closing date will be on Sunday, Nov. 1st, 2009 before 12:00 noon.

For more information, please contact:

Deputy Chief Executive Officer for Agreements & Exploration

Egyptian General Petroleum Corporation (EGPC)

Tel. : +202 7065227 Fax: +202 7065207

Vice Chairman for Agreements and Exploration

Ganoub El Wadi Petroleum Holding Company (Ganope)

Tel. : +202 22686657 Fax: +202 22686658

Editorial

Nigeria and the market

The oil market has lost 300,000 b/d of supply in 2 months from a single exporter, and the price of crude is falling. Until demand began faltering as the world entered recession at the end of 2007, the mere threat of such a loss would have boosted prices at least temporarily. That it didn't happen this time shows how thoroughly conditions have changed.

The supply loss came in Nigeria, where rebellion is crippling production and transportation. In its July Oil Market Report, the International Energy Agency estimated June oil production in Nigeria at 1.72 million b/d from capacity of 2.55 million b/d. The 300,000 b/d loss due to a surge in violence adds to shut-ins totaling 500,000-600,000 since insurrection began at the end of 2005, according to IEA. Nigerian National Petroleum Corp. on June 25 said 1.4 million b/d of production was offline.

Retaliation

The disruption is largely the work of a group called Movement for the Emancipation of the Niger Delta (MEND). IEA says MEND has been retaliating against a two-part effort by the government to suppress the militancy. In May the Nigerian military launched attacks against warlords around Port Harcourt and offered cash payments to militants abandoning the rebellion. The government also offered to release an imprisoned MEND leader. MEND rejected the overture.

Production casualties from the consequent escalation in violence include these listed by IEA:

- A halving of production from levels of earlier this year by the Shell joint venture to 140,000 b/d. Last year the group produced an average 850,000 b/d from capacity estimated at 1 million b/d. In March, Shell declared force majeure on shipments of Bonny Light and Forcados crude.
- Loss by Eni of 24,000 b/d of Brass River crude flow due to pipeline sabotage on July 8. Eni earlier shut in 33,000 b/d of production because of damage to a pipeline linking production with the Brass River export terminal. Eni declared force majeure on Brass River exports on June 23.
- Shut-in by Chevron of 100,000 b/d of Escravos crude production, about one third of the company's Nigerian output, because of sabotage to pipelines.

Obviously, the threat to Nigerian production, spread vulnerably among 600 fields and carried by 6,000 km of pipeline, is serious. Yet a market that 2 years ago would have been in panic has shrugged off the loss as though it doesn't need the oil.

Alternative supplies indeed are at hand. Oil inventories held by economically developed members of the Organization for Economic Cooperation and Development are strongly above average both in volume and relative to expected consumption rates.

Replacement supply is available, too, from production that's promptly available but not on stream. In its latest report, IEA put spare production capacity among members of the Organization of Petroleum Exporting Countries, excluding Iraq, at 6.34 million b/d. June numbers in this category from recent years have been much lower: 2.63 million b/d in 2008, 3.47 million b/d in 2007, 2.61 million b/d in 2006, and 1.58 million b/d in 2005.

Spare production capacity tends to decline under the conditions that make inventories fall, when demand is rising and capacity isn't expanding in step. When available spare capacity falls below 2.5-3 million b/d, the market becomes very reactive to hints of problems in places like Nigeria and Venezuela. Those countries have demonstrated their vulnerability to the political disruption of oil production. Like Nigeria, Venezuela can produce about 2.5 million b/d. Spare capacity below those potential losses was the norm from 2002 until last year.

Now, demand-snuffing recession, capacity additions, and OPEC production cuts have filled inventories and swelled capacity surpluses. With all that oil in storage and all that potential output at ready, the broad market seems unperturbed by Nigerian production cuts. The crude price acts as though hitched to stock market indices.

A problem lurks, however. Nigeria produces the light, sweet crude that refiners increasingly favor and that tends not to back up in reserve. The country's troubles, especially if they worsen, will have market effects not yet evident to everyone. ✦

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Weak energy demand to persist through 2009

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

Demand for oil will shrink this year—as will demand for almost all sources of energy in the US—because of economic contraction. Gas, coal, and nuclear energy demand will decline, but the use of hydroelectric power generation and all other renewable energy sources will grow from last year.

Global oil demand will decline from 2008, led by a decrease in oil consumption by the world's advanced economies.

Production of crude and condensate in the US this year will increase, and imports will decline almost 6% from a year ago.

Volumes of crude and products in storage are abundant and are expected to remain that way even though worldwide oil production this year is forecast to shrink in excess of 2 million b/d on average.

Worldwide outlook

Worldwide oil demand will average 83.8 million b/d this year, down from the 2008 average of 86.2 million b/d. This is the latest demand estimate from the International Energy Agency, which has lowered its outlook repeatedly during the lingering global economic slump.

Economic weakness will cause oil demand inside the Organization for Economic Cooperation and Development to slump by 2.4 million b/d from last year's 47.5 million b/d, according to the latest estimates from IEA. Demand will fall in North America and in the OECD countries in Europe and Asia.

Outside the OECD, demand for oil will be unchanged from 2008, averaging 38.7 million b/d. IEA estimates that demand will decline in the former Soviet Union (FSU) but climb slightly in the Middle East and in China. In other non-OECD Asian countries, demand will move a little lower from last year.

The US will consume less natural gas this year due to weaker industrial, commercial, and residential demand, but supplies of gas will be plentiful. Inventories of gas are hefty as a result of a surge in production last year. The amount of gas produced in the US in 2009 will decline slightly as a result of much lower prices compared with those last year.

Oil demand averaged 87.5 million b/d in the first quarter of 2008, and then slid each successive quarter to bottom out at an estimated average 83.1 million b/d in the second quarter of this year. IEA forecasts that worldwide oil demand will climb in the third quarter to average 83.6 million b/d and then will grow again during this year's fourth quarter, aver-

aging 83.9 million b/d.

Meanwhile, supply from producers outside the Organization of Petroleum Exporting Countries also has been in decline. In particular, countries that are members of the Organization for Economic Cooperation and Development will post a 5.1% supply decline this year vs. 2008, according to IEA.

Declining oil production in the UK and Norway will lead the slump in OECD Europe oil supply this year, but OECD Pacific and North America will log small increases in 2009 oil output.

Among the non-OECD members, IEA forecasts sizable production increases this year in Brazil and China. Oil supply from FSU is expected to increase to average 13 million b/d this year, up from 12.8 million b/d last year. Russian production will be almost flat year-on-year, but IEA expects output increases in Azerbaijan and Kazakhstan.

Starting in September 2008, OPEC has agreed three times to lower crude output by a cumulative 4.2 million b/d. IEA reported that by June of this year, OPEC had reduced production by 2.9 million b/d, pegging effective spare production capacity at 5.2 million b/d.

Although the organization's crude production has been waning since it implemented the lower output ceilings, OPEC's NGL production has been climbing. NGL output from OPEC members this year will average 5.2 million b/d, up from 4.7 million b/d last year.

OGJ forecasts that OPEC crude output will average 28.4 million b/d this year, putting upward pressure on inventories. Combined with IEA's outlook for demand, the global stockbuild will average 500,000 b/d.

Oil prices

The threat of delayed economic recovery is combining with large oil inventories to keep a ceiling on oil prices this year. US demand for oil will remain weak throughout this year.

OGJ forecasts that in 2009, the average US wellhead crude price will drop 34% from last year to $62/bbl. Also, US refiner acquisition costs of domestic and imported crude will average $64/bbl, down from $94.73/bbl last year.

Since the front-month futures price of oil on the New York Mercantile Exchange closed at $145.29/bbl on July 3, 2008, the price has been driven down by the global economic contraction and weakening worldwide demand for oil.

The most recent projections from the International Monetary Fund are that worldwide economic output this year will contract by 1.4% and then expand next year by 2.5%. In 2008, worldwide output grew by 3.1%.

IMF projects that GDP this year will contract by 3.8% in the world's advanced economies but grow by 1.5% in the world's emerging market and developing economies.

World crude prices plunged from mid-2008 to the start of 2009, and then rebounded some by the middle of this year. For example, EIA figures show that all OPEC crudes averaged $121.52/bbl on June 1, 2008, and then dropped to $35.48/bbl on Jan. 1, 2009, before rising to $65.88/bbl on June 1.

The front-month NYMEX futures price of oil closed at a recent high of $72.68/bbl on June 11. The rise was disconnected from market fundamen-

Worldwide oil supply and demand

Table 1

	2008 1st Qtr.	2008 2nd Qtr.	2008 3rd Qtr.	2008 4th Qtr.	2008 Year	2009 1st Qtr.	2009 2nd Qtr.	2009 3rd Qtr.	2009 4th Qtr.	2009 Year
	Million b/d									
DEMAND										
OECD										
North America	24.8	24.4	23.6	23.9	24.2	23.5	22.6	22.7	22.9	22.9
Europe	15.3	15.0	15.4	15.3	15.3	14.9	14.2	14.8	14.8	14.7
Asia-Pacific	8.9	7.9	7.5	8.0	8.1	8.1	7.2	7.0	7.5	7.5
Total OECD	**49.0**	**47.3**	**46.6**	**47.2**	**47.5**	**46.6**	**44.0**	**44.6**	**45.2**	**45.1**
Non-OECD										
FSU	4.3	4.1	4.3	4.1	4.2	4.0	3.9	4.1	4.1	4.0
Europe	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
China	7.9	8.0	8.1	7.6	7.9	7.7	8.4	8.0	7.9	8.0
Other Asia	9.9	9.9	9.4	9.5	9.7	9.9	9.7	9.4	9.6	9.6
Latin America	5.7	6.0	6.0	5.9	5.9	5.7	5.9	6.0	6.0	5.9
Middle East	6.7	7.1	7.6	6.9	7.1	6.7	7.3	7.8	7.2	7.2
Africa	3.2	3.2	3.1	3.2	3.2	3.2	3.2	3.1	3.3	3.2
Total non-OECD	**38.5**	**39.0**	**39.3**	**38.1**	**38.7**	**37.9**	**39.1**	**39.0**	**38.7**	**38.7**
TOTAL DEMAND	**87.5**	**86.3**	**85.8**	**85.3**	**86.2**	**84.4**	**83.1**	**83.6**	**83.9**	**83.8**
SUPPLY										
OECD										
North America	14.2	14.0	13.6	13.8	13.9	14.2	13.8	13.8	14.0	14.0
Europe	4.9	4.8	4.6	4.8	4.8	4.9	4.4	4.1	4.4	4.4
Asia	0.6	0.7	0.7	0.7	0.6	0.7	0.7	0.7	0.7	0.7
Total OECD	**19.7**	**19.5**	**18.8**	**19.3**	**19.3**	**19.7**	**18.9**	**18.6**	**19.0**	**19.1**
Non-OECD										
FSU	12.8	12.9	12.7	12.7	12.8	12.8	13.1	12.9	12.9	13.0
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.8	3.8	3.8	3.8	3.8	3.7	3.8	3.9	3.9	3.8
Other Asia	3.7	3.6	3.7	3.7	3.7	3.7	3.6	3.7	3.7	3.7
Latin America	4.1	4.1	4.2	4.2	4.1	4.3	4.4	4.4	4.4	4.4
Middle East	1.7	1.6	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Africa	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total non-OECD	**28.7**	**28.7**	**28.6**	**28.7**	**28.7**	**28.8**	**29.2**	**29.2**	**29.2**	**29.1**
Processing gain	2.2	2.2	2.3	2.3	2.2	2.3	2.3	2.3	2.3	2.3
Other biofuels	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.4	0.3
Total non-OPEC	**51.0**	**50.8**	**50.1**	**50.7**	**50.6**	**51.2**	**50.7**	**50.5**	**50.9**	**50.8**
OPEC										
Crude	31.5	31.4	31.5	30.5	31.2	28.5	28.5	28.4	28.0	28.4
NGL	4.6	4.6	4.7	4.8	4.7	4.9	5.1	5.4	5.6	5.2
Total OPEC	**36.1**	**36.0**	**36.2**	**35.3**	**35.9**	**33.4**	**33.6**	**33.8**	**33.6**	**33.6**
Total supply	**87.1**	**86.8**	**86.3**	**86.0**	**86.5**	**84.6**	**84.3**	**84.3**	**84.5**	**84.4**
Stock change	(0.4)	0.5	0.5	0.7	0.3	0.1	1.2	0.7	0.6	0.5

Totals may not add due to rounding.
Source: International Energy Agency; OGJ estimates for OPEC 3rd and 4th qtr 2009 crude supply.

OGJ FORECAST OF US OIL SUPPLY AND DEMAND

Table 2

	First half 2009 Volume, 1,000 b/d	First half 2009 % change from 2008	Year 2009 Volume, 1,000 b/d	Year 2009 % change from 2008
DEMAND				
Motor gasoline	8,950	–1.0	9,010	0.2
Dist. 1-4	7,400	–1.0	7,443	0.2
Dist. 5	1,550	–1.0	1,567	0.2
Jet fuel	1,400	–11.8	1,427	–7.3
Dist. 1-4	977	–11.8	992	–7.3
Dist. 5	423	–11.8	435	–7.3
Distillate	3,710	–8.9	3,760	–4.7
Dist. 1-4	3,237	–8.9	3,260	–4.7
Dist. 5	473	–8.9	500	–4.6
Residual	575	–11.0	496	–20.3
Dist. 1-4	433	–11.0	372	–20.3
Dist. 5	142	–11.0	124	–20.3
LPG and ethane	1,900	–7.8	1,847	–5.0
Dist. 1-4	1,855	–7.8	1,796	–5.0
Dist. 5	45	–7.8	51	–5.0
Other products	2,145	–14.2	2,192	–10.8
Dist. 1-4	1,910	–14.2	1,948	–10.8
Dist. 5	235	–14.2	244	–10.8
Total domestic demand	**18,680**	**–6.1**	**18,732**	**–3.9**
Dist. 1-4	15,812	–6.2	15,810	–3.9
Dist. 5	2,868	–5.9	2,922	–3.9
Exports	**1,845**	**1.1**	**1,800**	**–0.1**
Dist. 1-4	1,554	1.1	1,499	–0.1
Dist. 5	291	0.7	301	–0.1
Total demand	**20,525**	**–5.5**	**20,532**	**–3.6**
Dist. 1-4	17,366	–5.6	17,309	–3.6
Dist. 5	3,159	–5.3	3,223	–3.5
SUPPLY				
Domestic production				
Crude & condensate	5,282	3.3	5,275	6.6
Dist. 1-4	3,886	3.3	3,850	6.6
Dist. 5	1,396	3.3	1,425	6.6
NGL	1,770	–4.5	1,770	–0.8
Dist. 1-4	1,709	–4.5	1,705	–0.8
Dist. 5	61	–4.5	65	–0.8
Total domestic production	7,052	1.2	7,045	4.6
Dist. 1-4	5,595	0.8	5,555	4.2
Dist. 5	1,457	2.9	1,490	6.3
Imports				
Crude oil	9,360	–4.0	9,170	–5.8
Dist. 1-4	8,214	–4.0	8,034	–5.8
Dist. 5	1,146	–4.0	1,136	–5.9
Products & unfinished oils	2,900	–11.5	2,975	–5.6
Dist. 1-4	2,736	–11.5	2,805	–5.6
Dist. 5	164	–11.5	170	–5.6
Total imports	**12,260**	**–5.9**	**12,145**	**–5.8**
Dist. 1-4	10,950	–6.0	10,839	–5.7
Dist. 5	1,310	–4.9	1,306	–5.8
Processing gain, loss, etc.	1,345	–28.6	1,383	–26.4
Dist. 1-4	1,103	–28.6	1,134	–26.4
Dist. 5	242	–28.6	249	–26.4
Total new supply	**20,657**	**–5.6**	**20,573**	**–4.3**
Dist. 1-4	7,648	–5.8	17,528	–4.3
Dist. 5	3,009	–3.9	3,045	–4.2
Stock change	**132**	**—**	**41**	**—**
Dist. 1-4	282	—	219	—
Dist. 5	–150	—	–178	—
Crude runs to stills	**14,350**	**–3.6**	**14,400**	**–1.7**
Total input to stills	**14,690**	**–3.4**	**14,770**	**–1.7**
Total refining capacity	**17,672**	**0.4**	**17,675**	**0.4**
Refining utilization, %	**83.1**	**–3.8**	**83.6**	**–2.1**
Total industry stocks*	**1,110**	**13.3**	**1,050**	**1.4**
Refined products	760	11.1	720	1.6
Crude oil	350	18.2	330	1.2
SPR crude oil stocks	724	2.5	725	3.3
IMPORT DEPENDENCY				
Total imports % domestic demand	65.6	—	64.8	—
Net imports % domestic demand	55.8	—	55.2	—

*Million bbl at end of period.

tals; rather it was due to optimistic expectations of future demand based on early signs of economic recovery. Investors saw oil as a safe commodity and a good store of value in which to invest.

Oil prices retreated in early July due to signs of continued economic sluggishness and therefore a further delay in oil-demand recovery. Lower forecasts of 2009 oil demand sent futures prices below $60/bbl by July 10.

Product prices

Like crude prices, retail prices for all oil products will be sharply off their 2008 highs. This will be the first year since 2002 that annual average retail gasoline prices have declined.

OGJ forecasts that the pump price for all types of motor gasoline in the US will average $2.30/gal this year. Last year the pump price of regular and premium unleaded gasoline averaged $3.317/gal, according to EIA.

Heating oil prices also will retreat from their 2008 record average of $3.22/gal excluding taxes. OGJ expects heating oil will decline 29% this year.

Prices of diesel fuel, jet fuel, and propane also will post lower averages this year as compared with 2008 prices.

US economy

OGJ forecasts that gross domestic product in the US this year will decline 2%. The US economy shrunk 5.5% in this year's first quarter, as reported by the Bureau of Economic Analysis.

As the Federal Reserve Board reported following its latest decision to leave the federal funds interest rate unchanged at ¼% or less, new data show that the pace of economic contraction is slowing. Household spending has shown further signs of stabilizing but

remains constrained by ongoing job losses, lower housing wealth, and tight credit, the FRB said.

Consumer credit has been in decline since the fourth quarter of 2008, and unemployment at the end of June reached 9.5%—the highest level in 26 years.

The Bureau of Labor Statistics reported that since the start of the recession in December 2007, the number of unemployed persons has increased by 7.2 million, and the unemployment rate has risen by 4.6 percentage points.

Last year GDP grew by 1%, posting declines in the third and fourth quarters following a first half with economic growth.

US energy demand this year will contract faster than the economy. OGJ forecasts that demand for energy will shrink in 2009 such that energy efficiency improves to 8,430 btu/dollar from 8,520 btu/dollar a year ago.

Energy by source

The use of renewable energy sources will climb this year in the US, but demand for all other sources of energy will contract from a year ago. Total US energy demand will decline 3% from last year to 96.29 quadrillion btu (quads).

Oil and gas will account for 61.45% of the US energy market this year, the same share the two sources combined for last year, but coal's share of the market will decline. Nuclear energy, hydroelectric power, and other renewable energy sources will pick up coal's decline in market share.

OGJ forecasts that US oil demand will decline nearly 4% this year, totaling 35.837 quads. Demand for almost all of the major petroleum products will decline sharply from last year's weak numbers.

Economic weakness also will result in a decline in gas use, which OGJ expects will drop 2% this year. Residential, commercial, and industrial demand for gas will move lower, but gas demand in electric power will be little changed from a year ago. US gas demand this year will total 23.333 quads and garner 24.2% of the energy market.

Coal demand will fall 6% this year as a result of an overall reduction in

First quarter worldwide oil production

Table 3

Country	First quarter 2009	First quarter 2008	Change	Change, %
	1,000 b/d			
OPEC	**28,257**	**32,304**	**–4,047**	**–12.5**
Non-OPEC	**41,980**	**41,093**	**887**	**2.2**
Argentina	622	620	2	0.3
Brazil	1,913	1,766	147	8.3
Canada	2,638	2,584	54	2.1
Colombia	636	560	76	13.6
Mexico	2,667	2,911	–244	–8.4
United States	5,292	5,115	177	3.5
Other	2,947	3,209	–262	–8.2
Western Hemisphere	16,715	16,765	–50	–0.3
Norway	2,231	2,205	26	1.2
United Kingdom	1,451	1,484	–33	–2.2
Other	531	581	–50	–8.6
Western Europe	4,213	4,270	–57	–1.3
FSU	12,360	12,291	69	0.6
Other	163	174	–11	–6.3
Eastern Europe & FSU	12,523	12,465	58	0.5
Egypt	657	650	7	1.1
Gabon	240	227	13	5.7
Other	8,071	8,783	–712	–8.1
Africa	8,728	9,433	–705	–7.5
Oman	723	727	–4	–0.6
Syria	383	390	–7	–1.8
Other	19,744	21,929	–2,185	–10.0
Middle East	20,850	23,046	–2,196	–9.5
Australia	479	409	70	17.1
China	3,611	3,771	–160	–4.2
India	646	678	–32	–4.7
Indonesia	860	859	1	0.1
Malaysia	740	773	–33	–4.3
Other	872	928	–56	–6.0
Asia-Pacific	7,208	7,418	–210	–2.8
Total world	**70,237**	**73,397**	**–3,160**	**–4.3**

Source: Oil & Gas Journal

OPEC oil production

Table 4

Country	First quarter 2009	First quarter 2008	Change	Change, %	OPEC quota,[3] 1,000 b/d
	1,000 b/d				
Angola	1,717	1,891	–174	–9.2	1,517
Algeria	1,247	1,390	–143	–10.3	1,203
Ecuador	480	500	–20	–4.0	434
Indonesia[1]	—	859	—	—	—
Iran	3,713	4,023	–310	–7.7	3,336
Iraq	2,337	2,373	–36	–1.5	—
Kuwait[2]	2,337	2,583	–246	–9.5	2,222
Libya	1,583	1,763	–180	–10.2	1,469
Nigeria	1,813	2,057	–244	–11.9	1,673
Qatar	757	847	–90	–10.6	731
Saudi Arabia[2]	7,860	8,993	–1,133	–12.6	8,051
United Arab Emirates	2,287	2,623	–336	–12.8	2,223
Venezuela	2,127	2,400	–273	–11.4	1,986
Total OPEC	**28,258**	**32,302**	**–4,044**	**–12.5**	**24,845**

[1]Indonesia dropped out of OPEC at end of 2008. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. [3]Data provided by Centre for Global Energy Studies.
Source: Oil & Gas Journal.

WORLD CRUDE PRICES[1]

Table 5

Country	Type of crude and API gravity°	June 1, 2009, $/bbl	% change June 2009 Jan. 2009	In effect Jan. 1, 2009, $/bbl	% change June 2009 June 2008	In effect June 1, 2008, $/bbl	In effect June 1, 2007, $/bbl	In effect June 1, 2006, $/bbl	In effect June 1, 2005, $/bbl	In effect June 1, 2004, $/bbl
OPEC										
Saudi Arabia	Arabian Light 34	64.17	82.2	35.21	–46.9	120.79	63.68	45.96	33.77	23.52
Abu Dhabi	Murban 39	68.37	75.4	38.97	–46.0	126.63	69.77	52.67	37.53	26.69
Algeria	Saharan 44	67.42	80.1	37.44	–46.6	126.32	70.07	50.07	37.73	27.17
Nigeria	Bonny Light 37	68.58	72.1	39.85	–47.2	129.82	71.48	51.61	37.87	27.44
Libya	Es Sider 37	67.03	82.8	36.66	–45.0	121.80	67.55	49.88	37.34	26.57
Venezuela	Tia Juana 31	66.81	88.6	35.42	–45.8	122.26	64.71	47.69	36.92	27.81
Total OPEC		**65.88**	**85.7**	**35.48**	**–45.2**	**121.52**	**65.11**	**47.29**	**35.09**	**25.04**
OTHER										
Indonesia	Minas 34	70.18	91.6	36.63	–45.2	127.97	69.85	50.81	38.06	28.24
UK	Brent Blend 38	66.55	93.9	34.33	–47.0	125.47	69.43	51.21	37.78	27.58
Norway	Ekofisk 42	67.67	81.8	37.22	–47.1	127.92	69.02	50.23	37.63	27.78
Mexico	Isthmus 33	66.70	88.9	35.31	–45.4	122.15	64.60	47.58	36.81	27.70
Russia	Urals 32	66.30	93.9	34.20	–44.6	119.69	64.74	47.61	35.78	26.16
Total World		**65.62**	**89.8**	**34.57**	**–45.9**	**121.36**	**64.67**	**46.65**	**35.29**	**25.72**
US		63.70	100.6	31.76	–45.9	117.82	63.84	44.79	34.83	25.50

[1]Represents estimated contract prices based on government stated prices, netback deals, and spot market quotations. [2]Average prices (f.o.b.) weighted by estimated import volume.
Source: US Energy Information Administration

US CRUDE, PRODUCTS, AND NATURAL GAS PRICES

Table 6

Year	Average wellhead crude price, $/bbl	Refiner's acquisition cost of crude, $/bbl	Retail motor gasoline, all types, ¢/gal	Residential heating oil, ¢/gal	Average wellhead natural gas price, $/Mcf
1976	8.19	10.89	59.5	40.6	0.58
1977	8.57	11.96	63.1	46.0	0.79
1978	9.00	12.46	65.2	49.0	0.91
1979	12.64	17.72	88.2	70.4	1.18
1980	21.59	28.07	122.1	97.4	1.59
1981	31.77	35.24	135.3	119.4	1.98
1982	28.52	31.87	128.1	116.0	2.46
1983	26.19	28.99	122.5	107.8	2.59
1984	25.88	28.63	119.8	109.1	2.66
1985	24.09	26.75	119.6	105.3	2.51
1986	12.51	14.55	93.1	83.6	1.94
1987	15.40	17.90	95.7	80.3	1.67
1988	12.58	14.67	96.3	81.3	1.69
1989	15.86	17.97	106.0	90.0	1.69
1990	20.03	22.22	121.7	106.3	1.71
1991	16.54	19.06	119.6	101.9	1.64
1992	15.99	18.43	119.0	93.4	1.74
1993	14.25	16.41	117.3	91.1	2.04
1994	13.19	15.59	117.4	88.4	1.85
1995	14.62	17.23	120.5	86.7	1.55
1996	18.46	20.71	128.8	98.9	2.17
1997	17.23	19.04	129.1	98.4	2.32
1998	10.87	12.52	111.5	85.2	1.96
1999	15.56	17.51	122.1	87.6	2.19
2000	26.72	28.26	156.3	131.0	3.68
2001	21.84	22.95	153.1	125.0	4.00
2002	22.51	24.10	144.1	112.9	2.95
2003	27.56	28.53	163.8	135.5	4.88
2004	36.77	36.98	192.3	154.8	5.46
2005	50.28	50.24	233.8	205.2	7.33
2006	59.69	60.24	263.5	236.5	6.39
2007	66.52	67.94	284.9	259.2	6.37
2008	94.04	94.73	331.7	322.0	8.07
2009*	62.00	64.00	230.0	230.0	4.20

*OGJ estimate.
Source: US Energy Information Administration, for 1976–2008 data

electricity demand and increases in the use of other energy sources for electric power generation. OGJ expects coal demand will total 21.07 quads, comprising 21.9% of the US energy market. This compares with coal's 22.6% market share a year ago.

The use of nuclear power will be little changed from last year and will total 8.45 quads, a decline of only 0.1%. The number of operable nuclear units has held at 104 since 1998, and this year nuclear energy's share of the US energy market will be 8.8%. Nuclear energy accounts for about 20% of all electric power generation in the US.

Hydropower and the use of other renewable forms of energy will climb 2% this year, totaling 7.6 quads. This includes demand for wind, solar, and biofuels, as well as geothermal electric power generation and wood and waste energy. In total these renewable energy sources will account for 7.9% of all energy consumed in the US this year, up from 7.5% last year.

US oil demand

Demand for petroleum products in the US will fall to average 18.732 million b/d, down from the 2008 average of 19.497 million b/d.

Against weak second-half 2008 demand, gasoline demand in 2009 will grow, but only by 0.2%. OGJ forecasts that gasoline demand will average 9.01 million b/d this year.

Demand for gasoline plunged last year amid economic weakness, higher retail prices, and rising unemployment. Fewer miles are being driven as fewer workers commute and vacationers have cut many discretionary road trips.

Residual fuel oil, which is used in transportation as well as in power and

US ENERGY CONSUMPTION AND EFFICIENCY

Table 7

	GDP (billion 2000 dollars)	Energy consumption (trillion btu)	Energy consumption per GDP, 2000 dollar (Mbtu)	Oil energy consumption (trillion btu)	Oil energy consumption per GDP, 2000 dollar (Mbtu)	Natural gas energy consumption (trillion btu)	Total Natural gas energy consumption per GDP, 2000 dollar (Mbtu)	Total oil and natural gas energy consumption (trillion btu)	Oil and gas energy consumption per GDP, 2000 dollar (Mbtu)	Oil and natural gas energy % of total energy
1973	4,341.5	75,708	17.4	34,840	8.0	22,512	5.2	57,352	13.2	75.8
1974	4,319.6	73,991	17.1	33,455	7.7	21,732	5.0	55,187	12.8	74.6
1975	4,311.2	71,999	16.7	32,731	7.6	19,948	4.6	52,679	12.2	73.2
1976	4,540.9	76,012	16.7	35,175	7.7	20,345	4.5	55,520	12.2	73.0
1977	4,750.5	78,000	16.4	37,122	7.8	19,931	4.2	57,053	12.0	73.1
1978	5,015.0	79,986	15.9	37,965	7.6	20,000	4.0	57,965	11.6	72.5
1979	5,173.4	80,903	15.6	37,123	7.2	20,666	4.0	57,789	11.2	71.4
1980	5,161.7	78,122	15.1	34,202	6.6	20,235	3.9	54,437	10.5	69.7
1981	5,291.7	76,335	14.4	31,931	6.0	19,928	3.8	51,859	9.8	67.9
1982	5,189.3	73,234	14.1	30,231	5.8	18,505	3.6	48,736	9.4	66.5
1983	5,423.8	73,066	13.5	30,054	5.5	17,357	3.2	47,411	8.7	64.9
1984	5,813.6	76,693	13.2	31,051	5.3	18,507	3.2	49,558	8.5	64.6
1985	6,053.7	76,493	12.6	30,922	5.1	17,703	2.9	48,625	8.0	63.6
1986	6,263.6	76,722	12.2	32,196	5.1	16,708	2.7	48,904	7.8	63.7
1987	6,475.1	79,156	12.2	32,865	5.1	17,744	2.7	50,609	7.8	63.9
1988	6,742.7	82,774	12.3	34,222	5.1	18,552	2.8	52,774	7.8	63.8
1989	6,981.4	84,886	12.2	34,211	4.9	19,712	2.8	53,923	7.7	63.5
1990	7,112.5	84,654	11.9	33,553	4.7	19,603	2.8	53,156	7.5	62.8
1991	7,100.5	84,522	11.9	32,845	4.6	20,149	2.8	52,994	7.5	62.7
1992	7,336.6	85,866	11.7	33,527	4.6	20,835	2.8	54,362	7.4	63.3
1993	7,532.7	87,579	11.6	33,841	4.5	21,351	2.8	55,192	7.3	63.0
1994	7,835.5	89,248	11.4	34,670	4.4	21,842	2.8	56,512	7.2	63.3
1995	8,031.7	91,174	11.4	34,437	4.3	22,671	2.8	57,108	7.1	62.6
1996	8,328.9	94,176	11.3	35,673	4.3	23,085	2.8	58,758	7.1	62.4
1997	8,703.5	94,766	10.9	36,160	4.2	23,223	2.7	59,383	6.8	62.7
1998	9,066.9	95,183	10.5	36,817	4.1	22,830	2.5	59,647	6.6	62.7
1999	9,470.3	96,817	10.2	37,838	4.0	22,909	2.4	60,747	6.4	62.7
2000	9,817.0	98,975	10.1	38,264	3.9	23,824	2.4	62,088	6.3	62.7
2001	9,890.7	96,326	9.7	38,186	3.9	22,773	2.3	60,959	6.2	63.3
2002	10,048.8	97,858	9.7	38,227	3.8	23,558	2.3	61,785	6.1	63.1
2003	10,301.0	98,209	9.5	38,809	3.8	22,897	2.2	61,706	6.0	62.8
2004	10,675.8	100,351	9.4	40,294	3.8	22,931	2.1	63,225	5.9	63.0
2005	10,989.5	100,485	9.1	40,393	3.7	22,583	2.1	62,976	5.7	62.7
2006	11,294.8	99,875	8.8	39,958	3.5	22,224	2.0	62,182	5.5	62.3
2007	11,523.9	101,554	8.8	39,773	3.5	23,628	2.1	63,401	5.5	62.4
2008	11,652.0	99,275	8.5	37,137	3.2	23,809	2.0	60,946	5.2	61.4
*2009	11,419.0	96,260	8.4	35,837	3.1	23,333	2.0	59,170	5.2	61.5

*Estimated.
Source: US Energy Information Administration

US ENERGY DEMAND

Table 8

	2008	*2009	Change, %	% share of total energy 2008	% share of total energy *2009
	Trillion btu				
Oil	37,137	35,837	–3.9	37.4	37.2
Gas	23,809	23,333	–2.0	24.0	24.2
Coal	22,421	21,070	–6.0	22.6	21.9
Nuclear	8,455	8,450	–0.1	8.5	8.8
Hydro, other	7,453	7,600	2.0	7.5	7.9
Total	**99,275**	**96,290**	**–3.0**	**100.0**	**100.0**

*OGJ estimate.
Source: 2008 US Energy Information Administration

industrial plants, will incur the largest drop in demand among all the oil products. Fuel switching to cleaner and relatively cheaper fuels when possible will drive down 2009 resid demand to average 496,000 b/d, a 20% decline from a year ago.

Jet fuel demand will post a 7% decline from last year as a result of fewer flights and a drop in demand for passenger and cargo traffic. Demand averaged 1.4 million b/d in this year's first half, down 11% from first-half 2008.

The Air Transport Association of America reported that the number of passengers traveling on US airlines in May fell 9.5% from the same 2008 period, as weak demand was exacerbated by the impact of the H1N1 influenza outbreak.

Dampened by a decline in demand for both diesel fuel and heating oil, the use of distillate fuel oil will drop 4.7% to average 3.76 million b/d this year. Last year, distillate demand fell 6%, plunging during the summer months when distillate prices were unusually high.

Demand for propylene, propane, and all liquified petroleum gases, which are mostly used by industrial customers, will shrink 5% to average 1.847 million b/d this year.

The use of all other petroleum products will average 2.192 million b/d this year, declining almost 11% from last year. This category of products includes those used in construction, such as asphalt and road oil, as well as waxes, petrochemical feedstocks, lubricants, pentanes plus, and petroleum coke.

US oil production

OGJ forecasts that 2009 production of crude and condensate in the US will average 5.275 million b/d, climbing

US NATURAL GAS SUPPLY AND DEMAND

Table 9

	2006	2007	2008	Change, % 08/07	2009	Change, % 09/08
	bcf				bcf	
Production						
Texas	5,548	6,092	6,969	14.4	6,900	–1.0
Louisiana	1,361	1,364	1,350	–1.0	1,335	–1.1
Federal Gulf of Mexico	2,902	2,799	2,345	–16.2	2,550	8.7
Other states	9,599	9,764	10,778	10.4	10,443	–3.1
Total production	**19,410**	**20,019**	**21,442**	**7.1**	**21,228**	**–1.0**
Imports						
Canada	3,590	3,783	3,586	–5.2	3,227	–10.0
Mexico	13	54	43	–20.4	10	–76.7
LNG	584	771	352	–54.3	528	50.0
Total imports	**4,187**	**4,608**	**3,981**	**–13.6**	**3,765**	**–5.4**
Supplemental gas	66	63	55	–12.7	60	9.1
Losses, etc.*	(818)	(1,014)	(1,298)	28.0	(1,078)	–16.9
Total new supply	**22,845**	**23,676**	**24,180**	**2.1**	**23,975**	**–0.8**
Supply from storage	(436)	193	32	—	(260)	—
Total supply	**22,409**	**23,869**	**24,212**	**1.4**	**23,715**	**–2.1**
Exports	724	822	1,006	22.4	965	–4.1
Total consumption	**21,685**	**23,047**	**23,206**	**0.7**	**22,750**	**–2.0**

*Extraction losses and unaccounted for gas.
Source: 2006, 2007, 2008 EIA; 2009 OGJ.

from an average 4.949 million b/d last year. Output will get a boost from new fields coming on line this year, such as Murphy Oil Corp.'s Thunder Hawk field in the Gulf of Mexico (OGJ Online, July 9, 2009).

In the first half of this year, production increased almost 3% from a year earlier to average 5.282 million b/d. This increase was led by output gains in North Dakota, Louisiana, Montana, and California.

Production in Alaska climbed by an estimated 1.7% in this year's first half to average 713,000 b/d, but production was lower from a year earlier in Texas, Oklahoma, and Colorado.

Natural gas liquids production will be down slightly, averaging 1.77 million b/d vs. 1.784 million b/d last year.

Imports, exports

With demand down and inventories plentiful, US imports will decline this year. OGJ expects that crude imports will average 9.17 million b/d, a 5.8% decline from last year.

Product imports will decline at about the same rate, averaging 2.975 million b/d this year vs. 3.152 million b/d last year.

Sending an average 2.459 million b/d to the US, the leading source of US crude and product imports in 2008 was Canada. The second-leading source, averaging 1.532 million b/d last year, was Saudi Arabia, followed by Mexico, Venezuela, Nigeria, and Iraq.

The US will export 1.8 million b/d of crude oil and petroleum products, the same amount as last year. Almost all of the volume of oil that the US exports

FIRST HALF US CRUDE, CONDENSATE PRODUCTION

Table 10

	First half 2009*	First half 2008	Change, %
	1,000 b/d		
PAD District 1	22	20	10.0
Florida	6	5	20.0
Others	16	15	6.7
PAD District 2	558	509	9.6
Illinois	27	26	3.8
Kansas	104	107	-2.8
Michigan	15	17	-11.8
North Dakota	192	149	28.9
Oklahoma	176	180	-2.2
Others	44	30	46.7
PAD District 3	2,970	2,943	0.9
Alabama	21	21	–
Arkansas	16	17	-5.9
Louisiana	1,368	1,331	2.8
Mississippi	61	60	1.7
New Mexico	165	164	0.6
Texas	1,339	1,350	-0.8
PAD District 4	363	357	1.7
Colorado	63	66	-4.5
Montana	93	88	5.7
Utah	57	58	-1.7
Wyoming	150	145	3.4
PAD District 5	1,369	1,302	5.1
Alaska	713	701	1.7
California	655	600	9.2
Others	1	1	–
Total	5,282	5,131	2.9

*OGJ estimate.
Source: Energy Information Administration

US REFINERY UTILIZATION

Table 11

	Crude runs	Input to distillation units	Operable capacity	Utilization rate,
	1,000 b/d		%	
1987	12,851	12,999	15,643	83.1
1988	13,246	13,447	15,927	84.4
1989	13,401	13,551	15,701	86.3
1990	13,409	13,610	15,623	87.1
1991	13,301	13,508	15,707	86.0
1992	13,411	13,600	15,460	87.9
1993	13,613	13,851	15,143	91.5
1994	13,866	14,032	15,150	92.6
1995	13,973	14,119	15,346	92.0
1996	14,195	14,337	15,239	94.1
1997	14,662	14,831	15,594	95.2
1998	14,889	15,108	15,802	95.6
1999	14,804	15,078	16,282	92.6
2000	15,067	15,296	16,525	92.6
2001	15,086	15,351	16,512	92.6
2002	14,947	15,180	16,700	90.7
2003	15,304	15,503	16,747	92.6
2004	15,517	15,781	16,982	93.0
2005	15,220	15,479	17,128	90.4
2006	15,240	15,598	17,400	89.7
2007	15,143	15,443	17,447	88.5
2008	14,648	15,027	17,607	85.3
2009*	14,400	14,770	17,675	83.6
1990-2009 change				
Volume	1,239	1,160	2,052	–
Percent	7.4	8.5	13.1	–
2008-09 change				
Volume	(248)	(257)	68	–
Percent	-1.7	-1.7	0.4	–

Source: US Energy Information Administration

is in the form of products rather than crude.

Oil inventories

US inventories of crude and products at yearend will be slightly larger than at yearend 2008.

At midyear, about 350 million bbl of crude were held in commercial stocks, including 30 million bbl at Cushing, Okla. A year earlier crude stocks at Cushing totaled about 20 million bbl.

Declining imports will relieve some of the pressure on these inventories through the rest of the year. OGJ forecasts that crude stocks, excluding crude held in the Strategic Petroleum Reserve (SPR), will stand at 330 million bbl at the end of this year. Crude held in the SPR will total 726 million bbl at yearend, OGJ forecasts.

Product inventories will total 720 million bbl at the end of this year, down from 760 million bbl at midyear. Total products in storage stood at 709 million bbl at yearend 2008.

Stocks of distillate at mid-2009 were 27% higher than a year earlier, while the amount of gasoline in stocks was little changed from mid-2008. Resid in storage at the middle of 2009 was down about 10% from a year earlier.

Refining

Poor refining margins and large oil product inventories amid weak demand will weigh on refinery utilization this year, bringing the average utilization rate at US refineries to 83.6%, down from 85.3% a year ago. Operable capacity will total 17.675 million b/d.

First-half 2009 refining margins moved sharply lower from those a year ago. West Coast refiners incurred the mildest hit, with cash margins down 21% to average $12.27/bbl in the first 6 months of this year, according to Muse, Stancil & Co.

East Coast refiners' cash margin averaged just $1.61 in this year's first half, down 39% from a year earlier, while the margin for Gulf Coast refiners

US oil imports

Table 12

Sources of crude imports[1]

Country	Share of total 2009, %	First quarter average 2009, 1,000 b/d	Change 09/08, %	Annual average 2008, 1,000 b/d	Change 08/07, %	Annual average 2007, 1,000 b/d
Angola	6.4	612	21.4	504	1.2	498
Ecuador	2.5	241	12.6	214	8.1	198
Nigeria	6.4	607	–34.2	922	–14.9	1,084
Saudi Arabia	11.9	1,128	–25.0	1,503	3.9	1,447
Venezuela	10.8	1,029	–1.0	1,039	–9.5	1,148
Other OPEC	11.9	1,131	–8.3	1,233	21.7	1,013
Total OPEC	**49.9**	**4,748**	**–12.3**	**5,415**	**0.5**	**5,388**
Canada	20.0	1,901	–2.8	1,956	3.6	1,888
China	0.1	5	–54.5	11	83.3	6
Colombia	2.5	235	32.0	178	29.9	137
Gabon	1.1	106	82.8	58	–7.9	63
Indonesia[2]	0.2	21	31.3	16	6.7	15
Mexico	12.7	1,203	1.3	1,187	–15.8	1,409
Norway	0.6	61	103.3	30	–46.4	56
Trinidad and Tobago	0.5	51	121.7	23	–52.1	48
UK	0.6	56	–28.2	78	–22.8	101
Other non-OPEC	11.8	1,122	35.0	831	–9.7	920
Total imports	**100.0**	**9,509**	**–2.8**	**9,783**	**–2.5**	**10,031**

Sources of refined product imports

Algeria	9.0	281	19.1	236	4.0	227
Saudi Arabia	0.7	22	–15.4	26	–31.6	38
Venezuela	5.5	172	15.4	149	–29.7	212
Other OPEC	2.2	70	–45.7	129	12.2	115
Total OPEC	**17.5**	**545**	**0.9**	**540**	**–8.8**	**592**
Canada	19.2	598	11.6	536	–5.3	566
Colombia	1.0	30	30.4	23	27.8	18
Italy	0.6	19	–64.2	53	–3.6	55
Mexico	4.1	127	10.4	115	–7.3	124
Netherlands Antilles	0.4	14	40.0	10	11.1	9
Virgin Islands	10.3	321	0.3	320	–7.5	346
Other non-OPEC	46.9	1,463	–4.7	1,535	–11.1	1,727
Total imports	**100.0**	**3,117**	**–0.5**	**3,132**	**–8.9**	**3,437**

[1]Includes imports for the Strategic Petroleum Reserve. [2]Dropped out of OPEC at end of 2008.
Source: US Energy Information Administration

First half US crude and products stocks

Table 13

	[1]2009, 1,000 bbl	Change 09/08, %	[1]2008, 1,000 bbl	Change 08/07, %	[1]2007, 1,000 bbl
Motor gasoline	210,000	–0.4	210,870	2.6	205,546
Jet fuel	42,000	5.4	39,845	–3.0	41,087
Distillate fuel oil	155,000	27.4	121,710	–1.7	123,800
Residual fuel oil	37,000	–10.2	41,212	14.1	36,124
Unfinished oils	89,400	0.8	88,697	0.2	88,561
Other	226,600	24.5	181,948	–4.3	190,138
Total products stocks	**760,000**	**11.1**	**684,282**	**–0.1**	**685,256**
Crude stocks[2]	350,000	18.3	295,772	–16.5	354,071
Total	**1,110,000**	**13.3**	**980,054**	**–5.7**	**1,039,327**

[1]At end of June. [2]Excludes Strategic Petroleum Reserve.
Source: US Energy Information Administration, 2007-08. 2009, OGJ estimate.

declined 59% to average $4.06/bbl over the first 6 months of this year.

Gas market

US demand for gas will decline 2% this year, keeping prices low and inventories full.

The economic recession has cut into industrial and commercial demand for gas. Industrial gas use has declined each month year-on-year starting in August 2008. Residential demand has been more resilient over this period, though, mostly due to cool winter weather.

Last year US gas demand was nearly flat, climbing 0.7% to 23.206 tcf, at the same time that production jumped 7.1% as a result of output from unconventional sources in the US, such as the Barnett shale.

The number of rigs drilling for gas has plunged over the past year—especially reduced are rigs drilling in higher-cost and conventional plays—as gas supply has outpaced demand. The number of US gas rigs operating in early July was 672, down from 1,544 a year earlier, according to Baker Hughes Inc.

OGJ forecasts that US gas production will decline 1% this year, totaling 21.228 tcf. Output from the federal Gulf of Mexico will jump to 2.55 tcf from 2.345 tcf last year. But gas production from Texas, Louisiana, and other states will move lower from a year ago.

US gas imports by pipeline will decrease from 2008 levels, but LNG imports will post a big increase. Growing global liquefaction capacity is placing an increasing surplus of LNG on the world market, and the US inevitably will absorb some of this supply.

Imports of gas from Canada this year stand to decline 10%, while imports from Mexico will shrink 77% to total just 10 bcf over the year. OGJ forecasts that the US will import 528 bcf of LNG, a 50% jump from a year ago.

The US will export 965 bcf of gas this year, 4% less than in 2008.

Since supply will far outpace demand, the amount of gas in storage will build by 260 bcf this year. First-quarter 2009 withdrawals were weak, totaling 698 bcf in January, 371 bcf in February, and only 98 bcf in March.

Natural gas prices

Gas futures prices hit a peak at $13.577/MMbtu on July 3, 2008, then began a retreat such that a year later, the closing price on the New York Mercantile Exchange was $3.615/MMbtu.

The recent lower price reflects an amount of gas in underground storage above the past 5 years' range of such stocks. At 2,796 bcf, the amount of working gas in storage at the beginning of July was 27% higher than a year earlier. The US wellhead price of gas will average $4.20/Mcf this year, plunging from last year's record $8.07/Mcf average. EIA estimates show that in the first quarter of 2009, gas at the wellhead averaged $4.35/Mcf. ✦

Modest US, Canada drilling pickup seen in second half

Alan Petzet
Chief Editor-Exploration

Drilling in the US and Canada could recover modestly in the last 6 months of 2009 if oil and gas prices stabilize or improve.

As oil prices tumbled from highs near $150/bbl in mid-2008, the rig count followed to 2009 lows. Rig activity has seemed to begin to stabilize and pick up again only in the last month.

What little strengthening the US rig count has been able to muster lately has been tied mainly to rigs drilling for oil, but oil price fluctuations have tested even that firmness in recent weeks.

Still, several onshore shale gas plays have shown strength through the drilling downturn.

Rig counts in the US and Canada have averaged about 37% lower in the first half of 2009 than they did in the first half of 2008.

Elsewhere in the world, comparing the same period shows declines of 10% in Africa, 7% in Europe, 5% in the Middle East, 4% in Asia-Pacific, and 2% in the Western Hemisphere outside the US and Canada. The international rig totals do not include figures for Iran, Iraq, Russia, or China onshore.

Here are highlights of OGJ's midyear drilling forecast for 2009:

- Operators will drill 36,788 wells in the US this year, down from an estimated 52,097 wells drilled in 2008.
- All operators will drill 3,534 exploratory wells of all types, down from an estimated 5,474 estimated last year.
- The Baker Hughes Inc. count of active US rotary rigs will average 1,235 rigs/week this year, down from 1,867 in 2008 and 1,768 in 2007.
- Operators will drill 9,854 wells in western Canada, down from an estimated 16,290 in 2008.

US activity

US rig utilization in January through June year to year was down 38% onshore and 14% offshore, according to Baker Hughes Inc.

Areas of first half year to year increase were in shale gas plays that buoyed rig counts in North Louisiana, Pennsylvania, and Arkansas, and in conventional drilling in Kansas.

Many operators responded decisively to the drops in commodity prices. Continental Resources Inc., Enid, Okla., for example, had been running 32 operated rigs in October 2008 with plans to increase to 35 by the end of the year but instead trimmed to 7 rigs on Feb. 26, 2009.

Wyoming, state of busiest drilling in terms of numbers of wells due to the Powder River basin coalbed methane play, fell about the same percentage as the total US onshore.

Most of the Texas districts were down 30-58% on the year, drilling off Texas was cut in half, and Texas inland waters drilling almost ceased.

Oklahoma averaged 109 rigs/week in the first half of 2009 versus 203 in the first half of 2008, and Colorado slid to 59 from 114.

Baker Hughes shows a slight increase in Alaska, but state officials who follow rotary and coil tubing drilling say the year to year first half well count is down 44%.

At the end of 2008, they said, the North Slope had 2 coil and 9 rotary rigs drilling and Cook Inlet had five rotary rigs running. As June ended, however, North Slope work fell to 7 development drilling operations (3 coil and 4 rotary) and only two rigs were drilling in Cook Inlet.

Geothermal drilling eclipsed oil and gas activity in Nevada. Operators spudded only one oil well in the first half of 2009 compared with four in early 2008 and 3 in the second half. Geothermal work has been running about 60% exploratory and 40% development drilling.

OGJ's Canadian forecast is based on a shrinking number of gas wells drilled, although drilling in British Columbia shale plays bucked that trend.

The 270-company Petroleum Services Association of Canada forecast on Apr. 30, that 10,000 wells will be drilled in Canada in 2009. The organization had previously forecast 2009 Canada drilling at 16,750 wells in November 2008 and 13,500 wells in January 2009.

Some 36% of the wells drilled in Saskatchewan in the first half of 2009 were horizontal wells, Saskatchewan Industry

How US, Canada drilling compare

Table 1

Average number of active rigs per week, year to date

	Jan. 1-June 27, 2008	Jan. 1-June 26, 2009
Alabama	4.1	3.2
Alaska	7.4	8.5
Arkansas	44.0	47.0
California	38.1	23.5
Land	36.9	22.5
Offshore	1.2	1.0
Colorado	114.0	59.5
Florida	0.1	0.5
Kansas	10.9	17.8
Kentucky	10.0	9.4
Louisiana	149.5	147.0
N. land	52.2	78.2
S. inland waters	20.0	6.4
S. land	25.5	16.5
Offshore	51.9	45.9
Michigan	0.8	0.0
Mississippi	11.3	11.1
Montana	11.3	2.2
Nebraska	0.1	0.2
Nevada	3.2	4.5
New Mexico	73.6	41.8
New York	6.3	2.0
North Dakota	58.7	49.2
Ohio	11.8	7.9
Oklahoma	203.1	109.1
Pennsylvania	20.1	28.4
South Dakota	1.7	0.2
Tennessee	4.8	2.4
Texas	886.8	469.2
Offshore	8.8	3.9
Inland waters	2.5	0.3
Dist. 1	23.9	10.5
Dist. 2	34.3	19.6
Dist. 3	62.2	36.5
Dist. 4	91.6	44.3
Dist. 5	182.8	106.4
Dist. 6	121.1	78.1
Dist. 7B	32.0	13.4
Dist. 7C	60.2	24.3
Dist. 8	128.3	54.4
Dist. 8A	22.5	15.3
Dist. 9	40.5	25.1
Dist. 10	76.2	37.0
Utah	40.3	20.2
Virginia	4.2	3.8
West Virginia	26.4	23.5
Wyoming	71.0	43.5
US total	**1,817.0**	**1,139.0**
US land	**1,732.0**	**1,079.0**
US offshore	**62.4**	**53.4**
Canada total	**341.2**	**210.7**

Source: Baker Hughes Inc.

International rig count

Table 2

Average number of active rigs per month, year to date

	Jan. 2008-May 2008	Jan. 2009-May 2009
WESTERN HEMISPHERE		
Argentina	82	56
Bolivia	2	3
Brazil	46	61
Chile	1	2
Colombia	40	29
Ecuador	7	10
Mexico	99	129
Peru	7	5
Trinidad	6	1
Venezuela	81	67
Other	1	1
Total Western Hemisphere*	**373**	**365**
ASIA-PACIFIC		
Australia	26	20
Brunei	3	4
China-offshore	20	23
India	83	75
Indonesia	65	67
Japan	3	3
Malaysia	11	14
Myanmar(Burma)	8	3
New Zealand	5	4
Papua New Guinea	4	2
Philippines	1	3
Taiwan	0	0
Thailand	11	12
Vietnam	7	7
Other	3	0
Total Asia-Pacific	**249**	**238**
AFRICA		
Algeria	27	26
Angola	5	4
Congo	2	2
Gabon	2	1
Kenya	0	0
Libya	15	14
Nigeria	9	6
South Africa	0	0
Tunisia	4	3
Other	2	3
Total Africa	**67**	**60**
MIDDLE EAST		
Abu Dhabi	12	11
Dubai	1	1
Egypt	52	50
Iran	—	—
Iraq	—	—
Jordan	0	1
Kuwait	12	12
Oman	54	52
Pakistan	20	20
Qatar	11	9
Saudi Arabia	78	70
Syria	21	22
Yemen	14	11
Other	1	1
Total Middle East	**275**	**261**
EUROPE		
Croatia	0	0
Denmark	2	3
France	1	1
Germany	8	9
Hungary	3	3
Italy	5	3
Netherlands	3	3
Norway	18	22
Poland	2	2
Romania	20	10
Turkey	5	5
United Kingdom	20	21
Other	7	6
Total Europe	**94**	**87**
Total World	**1,058**	**1,012**

*Excludes US and Canada
Source: Baker Hughes Inc.

and Resources reported, and total first half drilling was at less than half the levels of the previous 3 years.

Drilling off Canada's east coast remained at a low ebb in the first half of 2009.

EnCana Corp. was the primary driller in Alberta and British Columbia in 2008, although it drilled far fewer wells than it did in 2007, and Crescent Point Energy Trust was the busiest driller in Saskatchewan, said Nickles Daily Oil Bulletin. ✦

OIL & GAS JOURNAL WELL FORECAST FOR 2009

Table 3

State	First half 2009 Total wells	First half 2009 Exploratory wells	First half 2009 Field wells	Full year 2009 Total wells	Full year 2009 Exploratory wells	Full year 2009 Field wells	Full year 2009 Total footage (1,000)
Alabama	175	9	166	360	17	343	1,632
Alaska	60	8	52	125	13	112	848
Arkansas	415	71	344	880	147	733	6,186
California land	895	31	864	1,915	61	1,854	4,927
California offshore	3	–	3	7	–	7	44
Colorado	765	200	565	1,555	400	1,155	10,215
Florida	1	–	1	1	–	1	12
Illinois	130	39	91	295	84	211	726
Indiana	63	19	44	133	40	93	212
Kansas	1,829	132	1,697	3,914	274	3,640	13,656
Kentucky	414	14	400	882	26	856	2,487
Louisiana	1,169	116	1,053	2,534	281	2,253	24,475
North	835	88	747	1,885	228	1,657	17,679
South	122	6	116	235	11	224	2,367
Offshore	212	22	190	414	42	372	4,429
Michigan	177	28	149	365	55	310	626
Mississippi	105	10	95	200	18	182	1,866
Montana	75	10	65	145	18	127	980
Nebraska	17	4	13	36	8	28	184
Nevada	1	–	1	2	1	1	14
New Mexico - East	255	16	239	565	34	531	4,710
New Mexico - West	205	3	202	448	6	442	2,808
New York	20	1	19	43	1	42	171
North Dakota	244	50	194	520	98	422	6,544
Ohio	375	33	342	720	61	659	3,150
Oklahoma	1,072	47	1,025	2,214	93	2,121	17,048
Pennsylvania	2,700	273	2,427	5,724	595	5,129	20,360
South Dakota	4	–	4	8	1	7	32
Tennessee	46	13	33	98	28	70	223
Texas	4,045	357	3,688	8,208	708	7,500	73,062
Dist. 1	131	11	120	255	21	234	1,700
Dist. 2	230	34	196	470	67	403	4,560
Dist. 3	277	34	243	590	70	520	5,296
Dist. 4	340	31	309	625	55	570	6,506
Dist. 5	491	17	474	966	31	935	11,367
Dist. 6	560	67	493	1,135	136	999	12,813
Dist. 7-B	255	11	244	525	22	503	3,418
Dist. 7-C	320	16	304	650	30	620	5,029
Dist. 8	432	25	407	890	52	838	6,268
Dist. 8-A	312	30	282	655	63	592	3,689
Dist. 9	378	12	366	797	27	770	5,181
Dist. 10	297	63	234	610	124	486	6,805
Offshore	22	6	16	40	10	30	430
Utah	277	52	225	585	109	476	4,631
Virginia	240	25	215	495	53	442	1,342
Washington	1	1	–	1	1	–	15
West Virginia	865	104	761	1,790	220	1,570	8,302
Wyoming	955	39	916	2,020	83	1,937	10,779
US total	**7,598**	**1,705**	**15,893**	**36,788**	**3,534**	**33,254**	**222,267**
Western Canada	**4,305**	**903**	**3,402**	**9,854**	**2,037**	**7,817**	**43,759**
Alberta	3,114	604	2,510	6,515	1,244	5,271	26,874
Saskatchewan	650	122	528	2,150	404	1,746	9,333
Brit. Columbia	469	168	301	1,014	367	647	6,862
Manitoba	72	9	63	175	22	153	690
NWT + Yukon Terr.	4	3	1	9	–	9	57
Eastern offshore	3	1	2	7	2	5	47
Eastern land	42	5	37	95	10	85	192

Geithner: New commodities regs should not preclude hedges

Nick Snow
Washington Editor

Over-the-counter derivative regulatory reforms should not jeopardize businesses' efforts to manage financial risk, US Treasury Secretary Timothy F. Geithner said on July 10.

"We want to preserve their capacity to participate in bilateral transactions as hedges as we increase overall protection for investors," Geithner told a joint hearing of the US House Agriculture and Financial Services Committees.

A key consideration will be whether a hedge is a standardized contract on a regulated exchange or electronic trading system, or a customized bilateral agreement, Geithner said. The Obama administration does not want to make customized derivatives illegal, but it would like them to be much less appealing to investors than standardized contracts, he indicated as he outlined the administration's broad initial reform proposals.

"The lack of transparency in the OTC derivative markets, combined with insufficient regulatory policing powers in those markets, left our financial system more vulnerable to fraud and potentially to market manipulation," he told the committees.

"These problems were not the sole or the principal cause of the crisis, but they contributed to the crisis in important ways. They need to be addressed as part of comprehensive reform, and they cannot be adequately addressed within the present legislative or regulatory framework," Geithner maintained.

Members of Congress have charged that financial speculators used unregulated financial instruments to push crude oil prices to record levels by mid-2008. Some have introduced bills that would require all trades to occur on regulated exchanges. Independent oil and gas producers and others who use commodity hedges have said that excessive regulation could hurt them financially.

Backed by assets

Rep. Bill Cassidy (R-La.), an Agriculture Committee member, said utilities in his district have told him they need hedges to help keep consumers' bills from climbing, and that they back their commitments with their assets. He asked Geithner how such deals would be defined under the proposed new regulations.

"I've received several letters about this, and I'm sure you have too," Geithner replied. "We will need to look at this closely, but we intend to preserve the option for their use."

Geithner said the Obama administration's broad objectives are to keep OTC derivative activities from posing risks to the broader financial system's stability; to promote efficiency and transparency in OTC derivative markets; to prevent market manipulation, fraud, and other abuses; and to protect consumers and investors by making sure that OTC derivatives are not marketed inappropriately to unsophisticated parties.

To that end, Geithner said the administration would like all standardized derivative contracts cleared through well-regulated central counterparties and executed either on regulated exchanges or regulated electronic trading systems. It proposes encouraging substantially greater use of standardized contracts through capital requirements and other measures so that more OTC derivatives migrate to central clearinghouses and regulated exchanges. It also wants to require all OTC derivative dealers and other major market participants to be subject to substantial supervision and regulation, including conservative capital requirements.

The administration's proposals also include steps designed to make OTC derivative markets more transparent. It would do this by having the Commodity Futures Trading Commission and the Securities and Exchange Commission impose recordkeeping and reporting requirements, including an audit trail, on all OTC derivatives. "We will require that all OTC derivatives that are not centrally cleared be reported to a regulated trade repository on a timely basis," Geithner said.

He said the administration also would like to see Congress give CFTC and SEC "clear authority for civil enforcement and regulation of fraud, market manipulation, and other abuses in the OTC derivative markets." It also intends to work with the agencies to tighten standards for participating in OTC derivative markets, and continue to work with other governments to ensure that they match this strict and comprehensive regulatory regime, he said.

Defining contracts

Geithner said the definition of a standardized contract under the proposed regulations would be broad, would be capable of evolving with the markets, and would be difficult to evade. "We will employ a presumption that a derivative contract that is accepted for clearing by any central counterparty is standardized. Further attributes will include a high volume of transactions in the contract and the absence of economically important differences between the terms of the contract and the terms of other contracts that are centrally cleared," he explained.

"We also will require that regulators carefully police any attempts by market participants to use spurious customization to avoid central clearing and exchanges," the Treasury secretary continued. "In addition, we will raise capital and margin requirements for

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Stalemate likely on Section 526

US House and Senate committees have each approved amendments to Section 526 of the 2007 Energy Independence and Security Act. But the devil, once again, is in the details.

Rep. Henry A. Waxman (D-Calif.) fought for insertion of the section into the energy bill late in its conference. The section bars government agencies from signing contracts for fuel from unconventional sources with a bigger carbon impact than conventional sources.

Waxman's primary concern was a US Air Force coal-to-liquids program. But it quickly became apparent early in 2008 that the prohibition could be extended to oil produced from Canadian oil sands.

Waxman exchanged letters with US Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) on the matter, and the House passed a measure that aimed to clear things up. To many people, however, it did not.

"Last year, the House apparently tried to set a precedent," an oil industry lobbyist told me on July 10. "The problem is that while the House went on record, its language didn't really clarify what's on the books."

Senate went further

So when Bingaman's committee passed a broad-based energy bill on June 17, the components included a Section 526 provision proposed by Bingaman and Sam Brownback (R-Kan.) that went further than the House did in 2008.

Two House members, Dan Boren (D-Okla.) and K. Michael Conaway (R-Tex.), submitted language similar to the Brownback-Bingaman amendment to the House Rules Committee that was marking up the federal defense authorization bill, but it was ruled out of order. The committee also rejected a proposal by Rob Bishop (R-Utah) to give the US Defense secretary authority to waive Section 526's requirements if he considers it appropriate.

Instead, it approved an amendment on June 24 offered by a freshman, Gerald E. Connelly (D-Va.), which essentially reiterated the 2008 measure with language about fuel produced from a predominantly unconventional source. A day later, the full House passed the defense authorization bill, with the amendment, in a 416-0 vote.

Arguably conventional

"Section 526 originally had so many ambiguous provisions, and last year's amendment didn't help it. We would argue that oil from oil sands has been produced for decades and could reasonably be considered a conventional source, for example," the lobbyist said.

The goal remains to let US refiners keep using crude from Canadian oil sands, she said, adding that some people hoped the Senate would insert the Brownback-Bingaman amendment as it considered its own defense authorization bill beginning July 13. That would force a conference to reconcile differences with the Connelly amendment.

Otherwise, the lobbyist said, the only way would be for the House to address the question again in the Energy and Commerce Committee. That doesn't seem likely, since it is chaired by Section 526's author, she added. ✦

counterparties to all customized and noncentrally cleared OTC derivatives. Given their higher levels of risk, capital requirements for derivative contracts that are not centrally cleared must be set substantially about those for contracts that are centrally cleared."

Committee members asked what steps could be taken to assure full international cooperation so contracts don't simply move to significantly less regulated overseas venues. "Oil has driven the calls to reform how we regulate these markets, but it's globally traded," said Rep. David Scott (D-Ga.), a member of both committees.

Geithner said he approved of CFTC Chairman Gary G. Gensler's July 7 announcement that he would hold a hearing to establish federal limits on energy commodity speculation and consider whether various market participants should be exempt. "It's clearly an effort to begin to address price volatility issues, but I believe more steps need to be taken to make markets more transparent," he said.

He also conceded that there's a risk that some countries might not want to match new, tougher US regulations of OTC derivatives. The administration is working closely with governments in Europe and Asia to coordinate reforms, Geithner said. "We're trying to do something that's never been done, to move together so that trading doesn't move abroad, so we're trying to involve all global financial centers," he said.

Financial Services Committee Chairman Barney Frank (D-Mass.) suggested that legislation authorizing reforms could contain a provision allowing bilateral sanctions against any country which clearly tries to attract commodity trading business with looser regulations. He and Agriculture Committee Chairman Collin C. Peterson (D-Minn.) said that work on actual legislation probably won't begin until September, but that a hearing was needed now to discuss initial proposals and air concerns. ✦

US senators introduce bill to promote NGVs

Nick Snow
Washington Editor

US Senate Majority Leader Harry M. Reid (D-Nev.) joined Sens. Orrin G. Hatch (R-Utah) and Robert B. Menendez (D-NJ) in introducing legislation on July 8 to increase use of natural gas in US motor vehicles.

"Each day, our nation consumes about 21 million bbl of oil, more than 25% of the world's supply. Nearly 70% is imported from outside our borders. With only 3% of the world's oil reserves, we cannot produce our way to a safe and secure energy future," said Reid. "We must get serious about using cleaner-burning natural gas and renewable energy, and this legislation is a strong step in the right direction."

The three senators said their bill, S. 1408, would expand the alternative fuel vehicle and refueling property tax credits in several ways. It would make all dedicated NGVs eligible for a federal tax credit equal to 80% of the vehicle's incremental cost, instead of only some NGVs as is the case now. It would make all bifuel NGVs eligible for a 50% federal tax credit for the first time.

The bill would increase allowable incremental cost limits to more accurately reflect costs of producing or converting NGVs. For a light-duty vehicle, the purchase tax credit cap would climb to $12,500 from $5,000. For all other vehicles, the cap would be doubled.

The bill also would extend for 10 years alternative fuel credits for natural gas used as vehicle fuel, for the purchase of an NGV, and for installing NGV refueling equipment. It would let state and local governments issue tax-exempt bonds to finance NGV projects. It would authorize grants for light-duty and heavy-duty NGV engine development.

Other provisions

It would allow 100% of the cost of an NGV manufacturing plant that is placed in service before Jan. 1, 2015, to be expensed and to be treated as a deduction in the taxable year in which the facility was placed in service. This would decrease to 50% after Dec. 31, 2014, and would be phased out by Jan. 1, 2020.

S. 1408 also would require federal agencies, when complying with mandatory federal fleet alternative fuel vehicle purchase requirements, to buy dedicated alternative fuel vehicles unless the agency can show that alternative fuel is unavailable or that purchasing such vehicles would be impractical.

"We saw last summer how the wild

fluctuations in oil prices helped to wreck our economy and we've seen how pollutants from dirty fuels are wrecking our planet," said Menendez. "Our economic crisis has shined a spotlight on the urgent need for alternative, cleaner, and cheaper sources of energy that we don't have to import. By making it easier and cheaper to own a vehicle that runs on natural gas, we can help families save money on energy, create new manufacturing jobs, and clean our air."

Hatch said gas is an important vehicle fuel alternative not only because of its potential to increase US energy security, but also because it is significantly less expensive. He noted that he lobbied to include provisions encouraging more hybrid and alternative fuel vehicle development and use in the 2005 Energy Policy Act, but added that NGVs have not grown as quickly as gasoline-electric hybrids in the time since.

'An extra push'

"I believe strongly that an extra push is needed to spur the greater use of natural gas and to get more gas-fueled vehicles on the road," he maintained. He said Utah is in a position to lead the US in NGV use and refueling station placement, and that the state's governor, Jon M. Huntsman Jr., has helped promote making the state's major north-south highway, Interstate 15, an NGV corridor.

T. Boone Pickens, who joined the three senators at their press conference, said that the bipartisan bill would do more to reduce US dependence on foreign crude oil than any other piece of legislation in the past 40 years. "It will accelerate the use of natural gas in vehicles and is the only way I know to quickly and effectively reduce our dependence on foreign oil," he said.

The three senators introduced their bill a day after Colorado Gov. Bill Ritter announced that his energy office applied to the US Department of Energy for a $10 million grant to dramatically expand the use of compressed natural gas as a transportation fuel in the state. ✦

OPEC expected to add 2 million b/d to NGL capacity

Natural gas liquids and condensate projects slated for start-up 2009-10 in some countries of the Organization of Petroleum Exporting Countries will add 2 million b/d to capacity at peak output. That's according to the recently released Oil Market Report from the International Energy Agency. Despite the current weak market outlook, said the agency, the long-lead time expansion projects are moving forward.

Almost all the projects currently slated to come online over the next 18 months have been plagued by delays related to construction, engineering, and other technical complications as well as by a shortage of skilled labor.

Country plans

IEA data show that Middle East producers Saudi Arabia, Qatar, Iran, and the UAE will provide 90% of the increase, while Nigeria will account for the remaining 10%. "The critical need to boost natural gas output for reinjection at aging oil fields" is a primary focus for many of the projects, said the report.

In the Middle East, a shortage of gas supplies to meet rapidly rising domestic demand from the electric power sector, at desalination plants, and for industrial use has also kept expansion plans on track, if not on schedule.

- Saudi Arabia's capacity increases account for 34% of the growth over 2009-10, with peak capacity additions totaling 660,000 b/d. The nonassociated Hawiyah NGL recovery project will provide about half of the growth, with peak capacity of 300,000 b/d by about 2011. The project's start-up was delayed to 2009 from 2008, said IEA.

The Khursaniyah gas processing plant has also been overwhelmed with delays; installed capacity of 290,000 b/d NGL production is not expected to be operating until yearend 2009. An additional 70,000 b/d of condensate capacity is linked to the massive 1.2-million-b/d Khurais oil field development, which formally launched last month.

It is unclear, however, when the new capacity will be fully online, given Saudi Aramco's "challenge of adjusting its surplus crude operating capacity in the current weak demand environment," according to the report.

- After overcoming considerable construction and technical delays, Qatar is on track to ramp up gas liquids by a further 545,000 b/d by yearend 2010 with six projects at North field. Major capacity increments are likely from Qatargas Trains 4, 5, and 6 with a combined capacity of 460,000 b/d.

Start-up of the Al Khaleej Gas Phase 2 Project (AKG-2), being developed as part of the Ras Laffan LNG expansion project, will contribute 40,000 b/d to condensate production capacity. AKG-2 is being developed to supply natural gas to domestic markets, while associated condensate and NGLs is for export.

- IEA says Iran plans to increase its condensate and NGL capacity by about 245,000 b/d over 2009-10. The country's massive South Pars project has suffered delays and costly overruns, but completion of Phases 6-10 will provide most of the growth in capacity.

The gradual start-up of capacity at South Pars 6, 7, and 8 is key to the country's enhanced oil recovery project at onshore Aghajari field, according to the IEA report. The gas-reinjection project is designed to boost output levels by about 100,000 b/d but technical issues, the field's age, and challenging corrosive issues with the pipeline, may limit the recovery rate.

Other projects in Iran, such as the Anaran development, are on hold at present. StatoilHydro pulled out of the

project earlier this year, in part due to the costly overruns the company suffered during development of Phases 6-8.

• The UAE plans to add about 340,000 b/d of installed capacity by yearend 2010, with start-up of the delayed 270,000-b/d Habshan OGD3 processing slated for later this year.

• Nigeria's start-up of the Total-operated Akpo gas and condensate project will increase Nigeria's installed capacity by a further 175,000 b/d. The Akpo development came online ahead of schedule in April.

Nigeria's gas liquids capacity also will increase this year by production from Agbami and EA fields, brought online in second-half 2008. These fields will peak at 50,000 b/d and 40,000 b/d, respectively. ✦

Two LNG terminals receive commissioning cargoes

Warren R. True
Chief Technology Editor-LNG/Gas Processing

Two more land-based LNG regasification terminals received first cargoes recently.

A BG Group-owned LNG carrier tied up at the Quintero LNG regasification terminal in Chile. On July 14, Dragon LNG, the UK's third land-based terminal and second in Milford Haven in Wales, saw the arrival of another BG Group-owned carrier with its first commissioning cargo.

On July 14, BG Group-owned LNG carrier Methane Lydon Volney docked at Dragon LNG with cargo from Atlantic LNG. Photo from BG.

South America

The 145,000-cu m Methane Jane Elizabeth docked at the Quintero LNG regasification terminal, about 65 miles west of Santiago. The cargo was loaded at Atlantic LNG in Trinidad and Tobago.

The vessel is from BG Group's fleet of LNG carriers; BG also holds a 40% interest in GNL Quintero SA, which will operate the terminal. Other partners in the project are the Chilean national oil and gas company ENAP (20%), power company Endesa Chile (20%), and gas distribution company Metrogas SA (20%).

BG Group signed a 21-year LNG sales and purchase agreement 2 years ago to supply the terminal with up to 1.7 million tonne/year of LNG. The company said in its press release that, once fully operational, the terminal will have the capacity to meet up to 40% of Chile's current demand for natural gas.

The Quintero terminal will include two 160 000-cu m LNG storage tanks.

UK

On July 14, another BG Group LNG carrier, the 145,000-cu m Methane Lydon Volney, docked at Dragon LNG in which BG Group holds a 50% interest. Its cargo was also from Atlantic LNG.

In addition, BG Group has an agreement to use up to 50% of the terminal's sendout capacity for the next 20 years.

Dragon LNG has built and will operate the 4.4 million tpy terminal. Equity partners in Dragon LNG, besides BG Group, are Petronas (30%), and 4Gas (20%). BG Group (50%) and Petronas (50%) also have agreements governing capacity rights for a 20-year term, allowing them each 2.2 million tpy of throughput.

Dragon LNG is near the South Hook LNG terminal that began operation in March and in April received the first cargo out of the newly completed 15.6 million tpy Qatargas 2 project (OGJ Online, Apr. 6, 2009). South Hook is a joint venture of ExxonMobil, Total, and Qatar Petroleum.

The Qatari Q-Max (266,000 cu m) LNG carrier Bu Samra is scheduled to arrive at South Hook from Ras Laffan in Qatar. ✦

Valero getting into renewables via wind, ethanol

Paula Dittrick
Senior Staff Writer

Valero Energy Corp. is getting into renewables, having bought several ethanol plants earlier this year and having built a wind farm in northwest Texas near its McKee refinery.

The wind farm is scheduled to operate at full capacity in August. Valero, San Antonio, expects to generate 50 Mw/hr of electricity when the wind is blowing around Sunray, Tex., which will be enough to run the refinery 40 miles north of Amarillo.

The wind farm, consisting of 33 wind turbines at the 166,600 b/cd Sunray refinery, cost $115 million, said Valero spokesman Bill Day.

It's hard to know when the turbines will pay for themselves because they're compared against the cost of electricity generated with natural gas, and natural gas costs fluctuate significantly.

"We built the wind farm there because we had plenty of open space around the refinery. We own the land," Day said. "It's relatively inexpensive over the long term." He noted that the refinery will remain reliant on the electricity grid when the wind is not blowing.

In March, Valero announced plans to buy seven ethanol plants from VeraSun Energy for $477 million. The sale was approved by a Delaware bankruptcy judge. VeraSun of Sioux Falls, SD, filed for Chapter 11 bankruptcy protection in October 2008.

The refiner is open to possibly buying more ethanol plants, Day said, adding that the company "got the best that was available at that time. These ethanol plants were available at 30% of what it would have cost to build them." Valero operates the ethanol plants under a subsidiary.

Valero formed a group in 2008 called the Alternative Energy & Project Development Group, headed by Jim Gillingham, a senior vice-president, who has been plant manager at some of Valero's largest refineries.

AEPD has been making small investments in biofuels companies that are working on technologies like producing cellulosic ethanol, making fuel from landfill waste, and making biofuels from algae.

Although the greatest percentage of Valero's revenues will continue to come from the refining and marketing side of the business, alternative energy is growing rapidly and is becoming an important part of Valero's business.

Expanding the value chain

Deloitte LLP recently issued a report recommending that refiners capture more of the emerging value chain for transportation fuels.

Roger Ihne, a principal with Deloitte in Houston, said US refining margins are likely to shrink. Valero agrees with this scenario, Day said.

The US renewable fuel standard calls for 11.1 billion gal of renewable fuel to be blended into gasoline this year, escalating to 36 billion gal by 2022.

"Although somewhat ironic, refiners can leverage their operations experience and capital to embrace the regulations designed to significantly reduce the consumption of traditional transportation fuels," Ihne said in a study entitled, "A Tsunami of Change Bearing Down on the Refining Industry."

Noting that regulatory changes can provide business opportunities, Ihne said Valero is an example of a traditional refiner that is positioning itself into the emerging fuels market. ✦

Deloitte foresees trouble for US refining industry

Paula Dittrick
Senior Staff Writer

Refining margins in the US are likely to shrink in coming years because stricter fuel economy standards and rising mandates for blending ethanol and other biofuels will reduce gasoline demand, Deloitte LLP said in a recent study.

Roger Ihne, a principal with Deloitte in Houston, wrote a study entitled "A Tsunami of Change Bearing Down on the Refining Industry." He spoke with reporters about his findings during a news briefing on July 9.

"Over 15-20 years, we can expect to see a reduction in gasoline demand," Ihne said. He estimates 1.5 million b/d of US refining capacity will shut down although he did not give a date for when he expects that to happen.

He emphasized that he was not projecting "the demise of the refining industry." A lot of uncertainty exists while refiners await the outcome of proposed legislation about stricter fuel economy standards and renewable fuels mandates.

Climate change legislation also could add costs because refiners are expected to have to invest in ways to reduce greenhouse gas emissions.

"In the short run, refiners can reduce throughput or shut down less efficient units," Ihne said. "Over the long haul, though, it's hard to justify keeping a refinery operating while selling less output at a time when profit margins are declining and costly upgrades are required."

HISTORY REPEATING?

	Late 1970s	Now
Environmental legislation	Clean Air Act	Renewable fuels standards
	Tetra-ethyl lead	Carbon cap-and-trade debated
Passenger car mileage	CAFE standards set at 20 miles per gallon by 1980	CAFE standards raised to 35.5 miles per gallon by 2016
Vehicle technology	Four-cylinder cars commonplace	Toyota Prius sale in US exceed 700,000 since the year 2000.
	Honda Accord introduced	US lends $8 billion to Ford, Nissan, Tesla for energy efficient cars
Refinery utilization rate	Operating at 90% in 1977	Operating at 93% in 2004 (currently at 82%)
	Dropped to 69% in 1981	Projected to drop to 77% in 2020

Source: Deloitte LLP

He expects refineries along the Gulf Coast will be heavily hit by shrinking profit margins.

History repeating

"The golden age of refining ended last year when…the economy sank into recession," he said. "It won't be back any time soon." He said the age ended a 4-year run of good refining margins. "A lot of the assumptions refiners had just 2 years ago are likely to be turned on their head."

Ihne compares the current scenario that refiners are facing to the shakeout that followed the oil price shock in the late 1970s.

"The average refinery utilization rate dropped in the US to 84% in 1979, a little above where it is now," Ihne said. "It then fell to less than 80%, where it stayed until 1986. Over the next 2 decades, the number of US refineries was halved from 319 in 1980 to 149 in 2000."

The US Energy Information Administration has forecast the utilization rate for US refining will slide to 78.5% in 2010 as a result of reduced demand. The last time utilization rates were that low was 1985. EIA expects gasoline demand will decline by 13% by 2030. ✦

Al-Qaeda threatens China's overseas oil, gas interests

Eric Watkins
Oil Diplomacy Editor

The al-Qaeda terrorist organization has vowed to avenge the deaths of Muslims in the Chinese province of Xinjiang by targeting Beijing's extensive workforce and projects around the globe, including its oil and gas interests, according to a private intelligence report.

"Muslims worldwide have reacted angrily to the situation in Xinjiang, demonstrated for example by protests in Jakarta," said London-based risk analyst Stirling Assynt in a report for its clients. Stirling noted that the first militant group to formally react to the news of violence against Muslim Uighurs is al-Qaeda's Algerian offshoot, al-Qaeda in the Islamic Maghreb (AQIM), which also has a presence in Mauritania, Niger, and Mali.

According to Stirling, AQIM "has pledged to avenge the fallen Muslims in China by targeting the 50,000 Chinese workers in Algeria as well as Chinese projects and workers across North West Africa."

"This threat should be taken seriously," Stirling said, noting that just 3 weeks ago, AQIM forces "ambushed a convoy of Algerian security forces protecting Chinese engineers, killing 24 Algerian security officers."

Stirling said AQIM did not attack the Chinese engineers because the target was the project on which they were working, along with the security personnel themselves.

"Now, future attacks of this kind are likely to target security forces and Chinese engineers alike," the analyst said.

According to independent reports, as well as targeting the police and the army, AQIM has vowed to target the country's commercial and foreign interests—including the increased number of new opportunities in Algeria's oil and gas industry.

Taking no chances

While the group has not yet struck oil and gas networks in Algeria, international oil companies, including BP PLC, StatoilHydro, Repsol YPF SA, and Total SA, are taking no chances and operate under heavy security.

Although AQIM appears to be the first arm of al-Qaeda to state officially that it will target Chinese interests, other al-Qaeda affiliates are thought likely to follow their lead.

"Al-Qaeda in the Arabian Peninsula (AQAP) could well target Chinese projects in Yemen, which are seen to benefit the government of President Ali Abdullah Saleh, whom they are actively trying to topple," it said.

In Yemen, according to independent reports, Sinopec is planning to drill one well on each of its three exploration blocks this year, having announced a gas discovery on Block 71 late in 2008.

According to Stirling, the general situation (and perceived plight) of China's Muslims has resonated among the global Jihadist community.

Stirling said there is an increased amount of internet "chatter" among active Jihadists, who claim they want to see action to avenge the perceived injustices in Xinjiang.

"Some of these individuals have been actively seeking information on China's interests in the Muslim world (locations include North Africa in general, Sudan, Pakistan, and Yemen), which they could use for targeting purposes," Stirling said.

African targets

Even in North Africa, potential targets abound:

- In Algeria, China National Petroleum Corp. recently said its NGS-P-1 well on Block 438B in the Oued Mya basin encountered significant oil and gas flows that indicate a high probability of commerciality.
- In Niger, CNPC said its Faringa W-1 well, drilled on Agadem Block in April and May, hit 30 m of oil. CNPC said it has been drilling a number of evaluation wells since December and has collected significant reservoir data.

Elsewhere in Africa are other possible Chinese targets:

- In Chad, CNPC last month began work on a major oil pipeline in southwestern Chad, due to become operational in 2011, which will transport crude from Koudalwa field 300 km south of N'Djamena to the Djarmaya refinery north of the capital.
- In Nigeria, Sinopec recently acquired Addax Petroleum Corp., described by one observer as a major strategic step forward for Sinopec, giving it control of operations of the large Taq Taq field in Iraqi Kurdistan and highly prospective exploration acreage off Nigeria and Gabon.

"What remains to be seen is the response of AQ's senior leadership, which could be expected in the next 7-14 days, given the usual lag in statements issued by them," Stirling said.

On one hand they do not want to open a new front with China, but on the other their sense of Muslim solidarity compels them to help and to be seen to be helping.

"The most likely scenario is for AQIM and AQAP to be granted sufficient latitude to carry out a number of attacks against Chinese targets in their respective locations," Stirling said.

"This will demonstrate that AQ cares about Muslims in China but precludes the need for AQ Central to commit to a new, unwelcome campaign," the analyst concluded.

Underlining the significance of the Stirling report, in mid-June military units from Algeria, Tunisia, Morocco, and Libya began joint military exercises on methods of intervention in the event of an attack by terrorist involving chemical weapons or chemical related disasters.

"No country or region is immune to such attacks or incidents," said Nasma Baghli, the director of security and disarmament at the Algerian Ministry of Foreign Affairs, at the launch of the military exercises in Ain Naadja.

Around the same time, in the first operation of its kind, Malian government forces killed between 16 and 26 alleged AQIM members in an attack on its base in the Timetrine region near the border with Algeria. ✦

Suspected terrorists arrested for plotting attacks in Suez Canal

Egyptian authorities have announced the arrest of 26 men, most of them engineers and technicians suspected of links with the terrorist al-Qaeda organization, on charges of plotting attacks on oil pipelines and ships transiting the Suez Canal.

The Egyptian Interior Ministry allege that the suspects, 25 Egyptians and a Palestinian, who had prepared remote-controlled detonators and explosives, were in contact with the Islamic Army of Palestine and were awaiting instructions from an al-Qaeda operative based abroad.

Egyptian authorities, who confiscated explosives, electronics, and diving suits, alleged that the suspects had prepared the remote-controlled detonators and explosives out of armaments left in the Sinai Desert from Egypt's wars with Israel.

The US Energy Information Administration considers the Suez Canal and the nearby Suez-Mediterranean pipeline as one of the world's seven most important chokepoints or transits for oil, whose closure "would add 6,000 miles of transit around the continent of Africa."

Oil shipments from the Persian Gulf travel through the Canal primarily to European ports, but also to the US, EIA says, adding that more than 3,000 oil tankers pass through the Suez Canal every year, and represent about 25% of the canal's total revenues. ✦

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Terrorists target Canada

The Canadian oil and gas industry has been hit by a rash of terrorist attacks in recent years, and the outlook is for much of the same, at least according to a recent risk report.

The report, entitled "Resource Industries & Security Issues in Northern Alberta," states that five groups are considered the most likely to carry out efforts that would hinder development of Canada's petroleum reserves.

The five main threat groups include individual saboteurs, ecoterrorists, mainstream environmentalists, First Nations, and the Métis people, who constitute a distinct Aboriginal nation largely based in western Canada.

"All except the Métis have, at various times, used some combination of litigation, blockades, occupations, boycotts, sabotage, and violence against economic development projects, which they saw as a threat to environmental values or aboriginal rights," said the report's author, Tom Flanagan.

Small-scale attacks

"However, extra-legal obstruction is unlikely to become large-scale and widespread unless these various groups make common cause and cooperate with each other," said Flanagan, a professor of political science at the University of Calgary.

"Such cooperation has not happened in the past, and seems unlikely in the future, because the groups have different social characteristics and conflicting political interests," Flanagan said.

While Flanagan rules out the possibility of such cooperation among the five threat groups, along the way he makes some highly interesting observations about the people likely to carry out attacks on Alberta's oil and gas industry.

He says the Peace River country of Alberta and British Columbia, as the last homestead frontier in North America, has attracted many highly independent people who want to live undisturbed in remote bush land.

"These people may see roads, seismic cuts, and pipelines as an intrusion on their property rights, and perceive hydrocarbon emissions as a threat to their health," Flanagan said.

Remote homesteaders

These remote homesteaders are well equipped to carry out acts of sabotage since they own firearms for hunting and self-protection in the wilderness; and they are familiar with heavy machinery because of their work as farmers, ranchers, lumberjacks, drill hands, and truck drivers.

They are not easy to detect and apprehend in such a vast expanse of territory, especially where they have some community sympathy.

"They will probably remain a nuisance factor, imposing extra security costs on natural-resource industries, but not bringing such industries to a standstill," Flanagan said.

If there is a problem with Flanagan's report, however, it is his exclusive focus on domestic sources of terrorism to the exclusion of any threat from abroad—a point noted by writer Andrew Nikiforuk.

"Most terrorism experts would say Alberta has made itself terribly insecure again by rapidly expanding oil and gas pipelines, and by becoming the No. 1 supplier of oil to the United States," said Nikiforuk. ✦

Uruguay to review offers for two blocks

Uruguay's Ancap has 180 days to review bids made for two offshore blocks in the country's first licensing round.

Both of the blocks that drew bids are in the Punta del Este basin. Uruguay has no hydrocarbon production, and Argentina has none in this part of the Atlantic Ocean.

Brazil's Petroleo Brasileiro SA, YPF SA, and Portugal's GALP Energia formed a group that bid for areas 3 and 4.

Area 3 covers 5,500 sq km in 100-2,000 m of water 150-300 miles off Montevideo, and Area 4 covers 3,000 sq km in 50-200 m of water 125-150 miles off Montevideo. Area 3 borders Argentina waters, and Area 4 is north of Area 3.

Interests are Petrobras and YPF 40% each and GALP Energia 20%.

YPF, a subsidiary of Repsol YPF of Spain, is Argentina's largest oil producer.

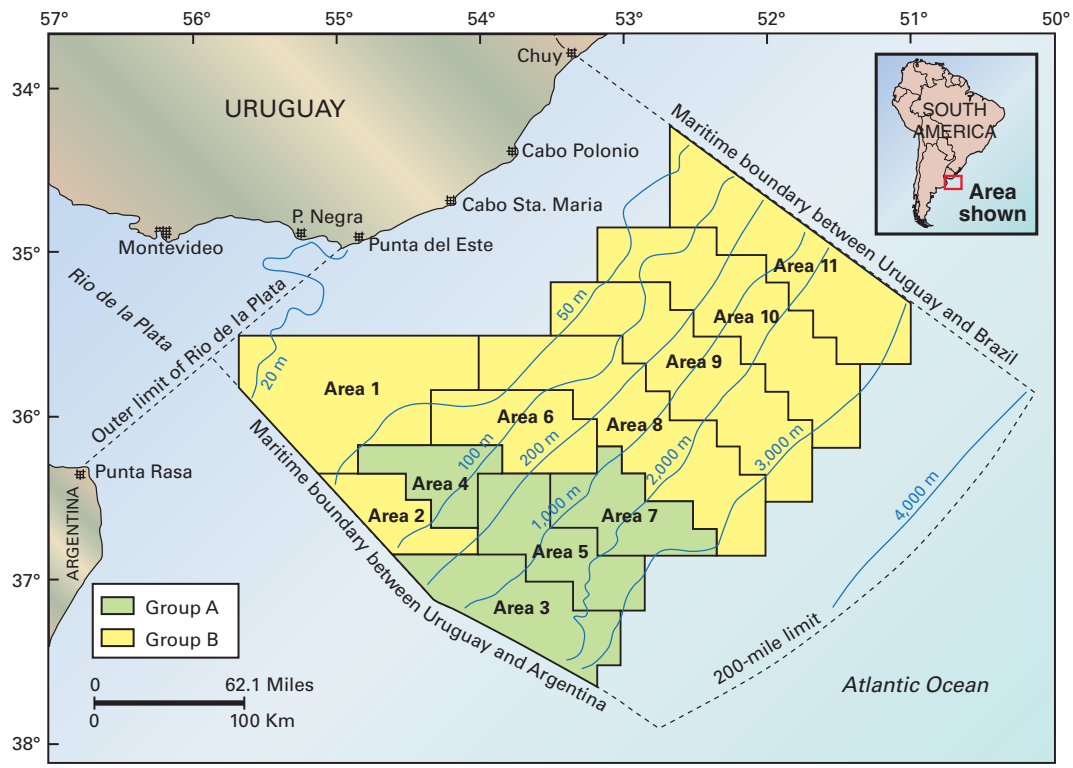
Ancap will evaluate the offers on behalf of the government and decide whether the bids should be accepted.

The initial term of the licenses, if issued, is 4 years, and Ancap has the right to participate in the exploitation phase if hydrocarbons are discovered.

Uruguay had offered 11 blocks in the Punta del Este, Pelotas, and Oriental del Plata basins (see map, OGJ, May 18, 2009, p. 19).

Besides the companies that bid, BHP Billiton, Petroleos de Venezuela SA, and Pluspetrol of Argentina had also qualified. ✦

URUGUAY'S 2009 BLOCK OFFERING



Ministry of Industry, Energy & Minerals

Total, Novatek to develop Termokarstovoye gas field

Total SA will develop the onshore Termokarstovoye gas field in Russian Arctic under a joint venture with OAO Novatek, Russia's largest independent gas producer.

Russian Prime Minister Vladimir Putin said the deal indicated Russia's strategic gas fields are open to foreign investment.

According to a heads of agreement, Total will take a 49% interest in Terneftegas, a wholly owned subsidiary of Novatek, with the remaining 51% interest in Novatek's hands.

A final investment decision on the estimated $900 million project is expected in 2011 once Novatek and Total complete appraisal and development studies. Termokarstovoye is 250 km east of Tarkosale where Novatek operates a processing facility for its own onshore production. The field has a potential of more than 47.3 billion cu m of gas and about 10.3 million tons of condensate.

Total's "technological capabilities will complement our experience developing complex geological assets and facilitate the effective development of the remote Termokarstovoye field," said Leonid Mikhelson, chief executive of Novatek.

The deal shall be closed upon approval of the Federal Antimonopoly Service.

It builds upon Total's other projects in Russia, including Shtokman gas-condensate field in the Barents Sea where the final investment decision is to be made next year. The Shtokman first development phase will produce 23.7 billion cu m/year, including 7.5 million tons/year that will be exported as LNG.

Total also operates Kharyaga field in the Nenets Autonomous Region. Under the third phase current production level will rise by 50% to 30,000 boe/d by 2011.

According to an analyst report from the Royal Bank of Scotland, the partnership between Total and Novatek could lead to expanded LNG cooperation on the massive South Tambey field.

"Termokarstov holds less than 6-7% of overall Novatek reserves, and we believe that by 2013 the field would contribute only about 1 billion cu m, or less than 2%, to Novatek production based on the 51% stake," the report said. "Novatek needs an international partner to develop this field and build an LNG facility, and we believe that Total, one of the top three companies worldwide in LNG and with an existing relationship with Novatek, is an ideal partner. Future cooperation on LNG is also facilitated by the enthusiastic support of the Kremlin, with Putin also calling for higher Russian LNG production."

Foreign investors have been hesitant to develop projects following Royal Dutch Shell PLC's significant cession of its stake in Sakhalin-2 to OAO Gazprom under intense government pressure. Under a draft law, the government stipulated foreign companies need approval from a special government commission if they want to participate in developing strategic oil and gas fields.

Christophe de Margerie, chief executive officer of Total, told the Moscow Times, "I don't think it's difficult to work in Russia. One only needs to learn to work efficiently with Gazprom, Novatek, and Rosneft. We're prepared to invest more into the Russian economy." ✦

USGS lists 76 billion boe on Barents Sea shelf

More than 76 billion boe may be technically recoverable on the Barents Sea shelf, the US Geological Survey said.

The mean estimate of undiscovered, conventional, technically recoverable petroleum resources in four geologic provinces on the Barents shelf included 11 billion bbl of oil, 380 tcf of natural gas, and 2 billion bbl of natural gas liquids.

The US Department of the Interior agency completed the assessment in 2008 as part of its Circum-Arctic Oil and Gas Resource Appraisal. The shelf lies entirely north of the Arctic Circle covering 1.76 million sq km off northern Norway and Russia. Most lies in less than 500 m of water.

"This area shares important characteristics with many Arctic basins, such as sparse data, high geologic uncertainty, substantial petroleum-resource potential, and technical barriers that impede exploration and development," the USGS report said.

Most of the undiscovered petroleum appears to be in the East Barents basin province, it indicated. ✦

Shah gas field development agreements signed

ConocoPhillips and Abu Dhabi National Oil Co. (ADNOC) have signed joint venture and field entry agreements for developing Shah gas-condensate field in Abu Dhabi.

The development involves onshore sour gas-condensate reservoirs in Shah field, about 180 km southwest of Abu Dhabi city.

The field, discovered in 1966, had original reserves of 500-600 million bbl of 30° gravity oil in Cretaceous carbonates at 8,000 ft. The gas-condensate is in the deeper Jurassic Arab formation (see map, OGJ, Aug. 18, 2008, p. 44).

The development includes construction of gas gathering systems, gas processing trains, and product pipe-

lines designed to process and transport 1 bcfd of gas, associated liquids, and sulfur.

The companies note that due to the sour gas, the development required extensive risk-assessment studies with front-end engineering and design stages selecting state-of-the-art health, safety, and environmental systems.

The project will included one the world's largest sulfur-removal plants as well as sulfur processing and exporting facility at Ruwais Industrial City, Abu Dhabi, according to the companies.

To date, the companies have released for tender 6 of 10 major engineering, procurement, and construction bid packages to prequalified contractors and plan to release the remaining EPC bid packages later this year. Tender results will be known in early 2010, the companies say.

ADNOC has a 60% interest in the joint venture with ConocoPhillips having the remaining 40%.

Personnel from both ADNOC and ConocoPhillips will staff the new operating company. ✦

Cameroon

Victoria Oil & Gas PLC expects to spud a well in mid-July to develop Logbaba gas-condensate field in the city of Douala, Cameroon.

Logbaba, discovered in the 1950s, has independently assessed proved and probable reserves of 104 bcf. Industrial customers are to take up to 8 MMcfd.

The development plan calls for drilling one new well to 10,000 ft, build a 12 MMcfd gas processing plant, and lay 15 km of 16-in. pipeline to the users. A second well would be drilled later. Production is to start in 2010.

Colombia

Test results at the Costayaco-8 development well in southern Colombia keep Gran Tierra Energy Inc., Calgary, on track towards a 19,000 b/d production plateau at Costayaco field in the 2009 fourth quarter, the company said.

The well made 2,640 b/d from the Caballos formation and 2,211 b/d from the Villeta Upper T sandstone. The rate was 2,988 b/d in 20 hr commingled on a jet pump. The company is building location for Costayaco-9, to spud July 14 some 1,958 ft southwest of Costayaco-8, and finalizing test results for Costayaco-7. Next up is Costayaco-10.

Indonesia

GeoPetro Resources Co., San Francisco, said its 12% owned Continental-GeoPetro (Bengara-II) Ltd. subsidiary let a contract for a seismic survey in the Bengara-II block in East Kalimantan, Indonesia.

An undisclosed local seismic contractor will shoot 120 sq km of 3D and 844 line-km of 2D seismic at an estimated acquisition cost of $28.5 million. A large part of the program is in the transition zone of the Bulungan River and Sulawesi Sea. Completion is set for 2010.

The surveys are mainly to delineate the Seberaba oil discovery and Makapan gas-condensate discovery. A large part of the 2D program is intended to further define exploration prospects, including the Galiadap structure, for drilling in 2010-11.

Trinidad and Tobago

Niko Resources Ltd., Calgary, obtained a 26% interest from Centrica PLC and becomes operator of Block 2AB off Trinidad and Tobago, its first block in the country.

The block covers 1,605 sq km near giant Angostura oil and gas-condensate field off northeastern Trinidad. Angostura is in 130 ft of water.

Other interests in Block 2AB are Centrica 29.25%, Voyager Energy 9.75%, and Petroleum Co. of Trinidad and Tobago 35%.

New York

The New York Department of Environmental Conservation issued three permits to a partner of Gastem Inc., Montreal, to drill wildcats to Ordovician Utica shale in west-central New York.

Two of the permits issued to Covalent Energy Corp., Arlington, how called Utica Energy, are for wells near Springfield in northern Otsego County. Gastem USA plans to begin drilling as soon as possible. The wells are to core the Devonian Marcellus shale and log the full vertical interval including the Silurian Oneida formation.

Studies compiled by Gastem's experienced Utica Geology Team on both successful Utica Energy test wells drilled in 2007 along with related area shale characteristics accumulated over the past year have confirmed the potential of the area, Gastem said.

Oklahoma

A group led by Beard Co., Oklahoma City, plans a secondary recovery project in Dilworth oil field in northern Oklahoma. Participants include Subsurface Minerals Group LLC, RSE Energy LLC, True Energy Exploration LLC, Royal Energy LLC, and Beard Dilworth LLC.

The project, in 17, 18, and 20-28n-1e, Kay County, 15 miles northwest of Ponca City, is expected to recover 3.4-4.4 million bbl at a peak projected rate of 220,000 b/d of fluid, 1-2% oil.

The field is estimated to have produced 70 million bbl of oil since discovery in 1911.

West Virginia

GeoMet Inc., Houston, engaged a divestment firm to market a 50% nonoperated working interest in 147 wells in the eastern part of Pond Creek field in West Virginia.

The company estimated that the 50% interest represented 20% of its net daily production and 10% of its proved reserves as of Dec. 31, 2008. A data room will be open until Aug. 14.

DRILLING MARKET FOCUS

Industry reports some price breaks as drilling contracts renegotiated

Paula Dittrick
Senior Staff Writer

Oil and gas executives report they are beginning to see some relief in drilling and completion costs, partially because service companies have become more willing to renegotiate contracts.

Producers are examining variable-pricing contract structures. Such contracts typically are tied to oil futures prices or the Baker Hughes rig count.

Doug Sheridan, managing director and founder of EnergyPoint Research Inc., sees a movement away from fixed-price contracts toward prices that reflect commodity prices, especially on the international oil markets.

For example, a drilling contract could contain day rates based upon predetermined price points such as if crude falls below $50/bbl for 30 days, he said. His independent market research firm specializes in monitoring customer satisfaction in the oil and gas industry.

Bill Hale of Ernst & Young LLP also said he sees a more variable pricing structure for drilling contracts within the US, based upon dropping revenues and a sluggish Baker Hughes Inc. rig count.

US drilling activity increased for the first time in 11 weeks, up by 23 rotary rigs to 899 drilling for the week ended June 19—the same number as 3 weeks earlier but down from 1,906 during the same period a year ago, Baker Hughes reported in its weekly statistics.

Barclays Capital Inc. analysts on June 22 forecast that worldwide exploration and production expenditures will reach $387 billion during 2009, which would be down 15% from last year.

Ensco International Inc. reports the Ensco 8500 started operations during June in the Gulf of Mexico. The first of seven new ultradeepwater semisubmersibles, Ensco 8500 has a 4-year contract with Anadarko Petroleum Corp. and Eni. Photo from Ensco International.

The forecast was based upon a survey of 402 companies.

"Growth in E&P is anticipated to return in 2010 by over half of the companies surveyed," said Barclays Capital analyst James D. Crandell in New York.

Producers' strategies vary

Occidental Petroleum Corp. Pres. Stephen Chazen said Occidental is renegotiating supplier contracts and laying down rigs. The company's first-quarter financial results included an $8 million pretax charge for terminated rig contracts.

Oxy expects a 20%-25% cost reduction across all areas compared with 2008 costs, he said. He expects the full effect of the cost reductions to be realized during the rest of this year and going into 2010.

Devon Energy Corp. Pres. John Richels in May said that Devon's costs have dropped 10-15% from the beginning of 2009, and the company expects costs to come down another 10-20% by yearend.

Apache Corp. stopped drilling in Oklahoma because rig rates were too high, compared with current natural gas prices. While it currently has no rigs running in Oklahoma, Apache said it had about 25 rigs drilling there last summer.

Speaking at the Reuters Global Energy Summit in Houston during early June, Apache Chief Executive Officer Steve Farris said he expects to see exploration costs continue to decline despite a recent rise in crude oil prices.

Rig rates in Oklahoma were about $12,000/day in early June. Farris said he expects that will fall to $7,500/day, which would be comparable with 2004 day rates. Rig rates in Oklahoma were $24,000/day last year.

Clayton Williams Energy Inc. plans to increase spending in response to lower drilling and completion costs and higher oil prices. The company plans two oil drilling projects in second-half 2009 in the Permian basin and Austin chalk.

The two projects will utilize up to five drilling rigs owned by Desta Drilling, the operating name for Larclay LP, a Clayton Williams Energy wholly owned subsidiary.

"Since we can control costs more effectively by using our own drilling rigs and by entering into firm pricing arrangements with our service providers, we feel confident in our ability to carry out our current plan under existing market conditions," said Clayton W. Williams Jr., president.

For the year ending December 2009, Clayton Williams Energy plans to spend $107.7 million on exploration and development activities compared with its earlier plans to spend $78.5 million.

OCCIDENTAL'S CHANGE IN CONTRACT TERMS

Category	Reduction from peak 2008 level, %
Drilling	15-30
Completion, workover	15-20
Production equipment, chemicals	15-25
Oil field materials	20-40
Field operations	15-25

Source: Occidental Petroleum Corp.

Jack up market deteriorates

Analysts with Raymond James & Associates Inc. have said the jack up market continues to deteriorate, and they expect offshore drilling contractors will need to continue stacking capacity.

Pritchard Capital Partners analysts said the Gulf of Mexico market already was weak before the arrival of hurricane season, which typically means minimal demand exists for small well jobs.

Ensco International Inc. reported in June that it had a total of nine jack ups idle. Ensco coldstacked its first two rigs, both in the Gulf of Mexico. The Ensco 90, a 24-year-old rig, was stacked along with the Ensco 60, a 28-year-old rig.

The Ensco 81, a 350-ft independent-leg cantilever (IC) jack up, had its indexed rate with Mexico's Petroleos Mexicanos cut $65,000 to $100,000/day, Pritchard analyst Stephen Berman said on June 16.

The Ensco 99, 250-ft IC jack up, had its current contract expiration extended 1 month at $75,000/day and then it will begin a 1-well job for Newfield Exploration Co. at $48,000/day, which Pritchard Capital called the lowest rate recorded for a 250-ft IC in the gulf.

The contract for Ensco 75, a 400-ft IC, expired and the rig is expected to be idle in July, Ensco said in a recent fleet status report. However, Ensco's deepwater expansion program is progressing and will buffer some weakness in its jack up business.

Dan Rabun, Ensco chairman, president, and chief executive officer, said the company has committed more than $3 billion to construct seven rigs to expand its ultradeepwater fleet.

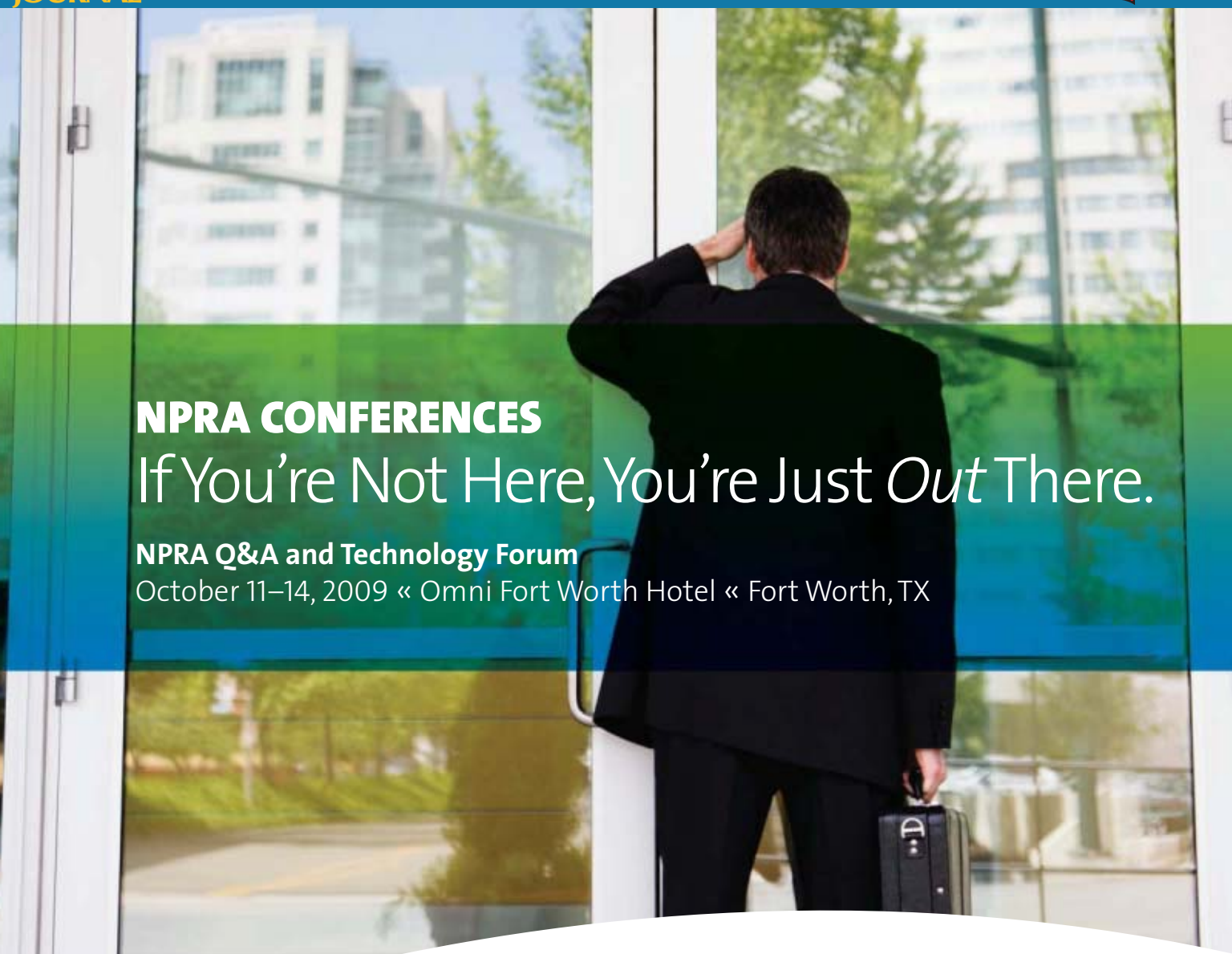
Ensco 8500, the first of seven new ultradeepwater semisubmersibles, started working during June in the gulf under a 4-year contract, signed in 2005, with Anadarko Petroleum Corp. and Eni.

The second semi in the series, Ensco 8501, was delivered in June from a shipyard and is mobilizing to the gulf with drilling operations scheduled to start in October.

Land Rigs stabilize

Helmerich & Payne Inc. disclosed in a US Securities and Exchange Commission filing during June that its US land rig count has stabilized since its April earnings report. As of June 15, the contract said 107 of 209 rigs, or 51%, were on contract and generating revenues, with 88 on long-term contracts.

Since Apr. 30, two more newbuild FlexRigs received early terminations, bringing H&Ps total contract terminations to 37, the company said. For international rigs, 14 of 32 were idle in June, implying 56% utilization. ✦



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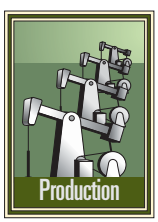
Return of most reserves lost in Gustav, Ike predicted

Mark J. Kaiser
Yunke Yu
Louisiana State University
Baton Rouge



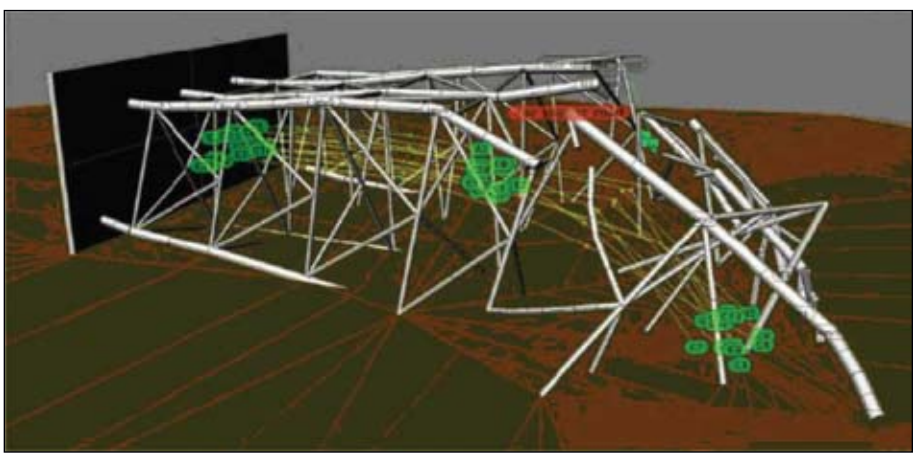
From our assessment, the gas structures damaged during Hurricanes Gustav and Ike in the Gulf of Mexico present better economics and redevelopment potential than oil structures, and we predict that companies will redevelop 196 million boe, or nearly 95% of the remaining reserves.

Each destroyed structure is a candidate for redevelopment and is unique in its production capacity and damages incurred.

During August and September 2008, Hurricanes Gustav and Ike passed through the gulf and damaged and destroyed many offshore oil and gas structures.

The final official government assessment listed 60 destroyed platforms and 31 extensively damaged structures. The destroyed platforms represented 1.6% of the oil and 2.5% of the gas produced in the gulf. Remaining reserves from these platforms are estimated at about 234 million boe valued between $4.6-10.9 billion.

Although the number of structures destroyed by Hurricanes Gustav and Ike was half the total destroyed from the 2004-05 hurricane seasons, we estimate that the reserves at risk are about twice as large and three times as valuable.



This rendition of a hurricane-destroyed structure shows the structure lying horizontally on the seafloor with bent conductors at the mud line (Fig. 1). Rendition from Twachtman Synder and Byrd Inc., now Proserve Inc.

Hurricanes

Powered by heat from the sea, a hurricane acts as a gigantic heat engine transforming warm ocean water into powerful wind fields. Hurricanes are typically about 300-350 miles wide and have extreme horizontal pressure gradients that generate powerful winds.

Wind speed and precipitation intensity both increase toward the center and generate waves and currents that stress offshore structures and may lead to catastrophic failure.

Hurricane force winds usually extend 25-50 miles on each side of the storm path and represent approximate boundaries where structures are most vulnerable. Typically, hurricanes destroy 2-4% of structures exposed to hurricane force winds and damage another 3-6%.

Old structures especially are vulnerable because these facilities have lower environmental criteria designs.

Structures fail in different modes and any wells underneath the deck and substructure usually bend at the mud line and require complex and expensive intervention to abandon.

Hurricanes may topple structures completely (Fig. 1) or leave the jacket structure standing (Fig. 2). Platform owners often declare leaning structures as destroyed (Fig. 3). In some cases, they may also declare as destroyed severely damaged structures that no longer can carry out their function.

In all cases, destroyed platforms present a hazard to navigation and require immediate identification as navigation hazards.

Hurricane Gustav entered the Gulf of Mexico on Aug. 31, 2008, as a Category 4 storm and exposed about 677

A hurricane destroyed this platform in the East Cameron Area (Fig. 2). Photo from US Minerals Management Service.

A hurricane probably caused the foundation of this platform to fail (Fig. 3). Photo from US Minerals Management Service.

platforms to hurricane force winds (Fig. 4). Hurricane Ike followed in Sept. 13, 2008, as a Category 4 hurricane and exposed about 1,450 structures to hurricane force winds (Fig. 5).

The final official government assessment listed 60 destroyed structures and 124 extensively or moderately damaged structures.[1]

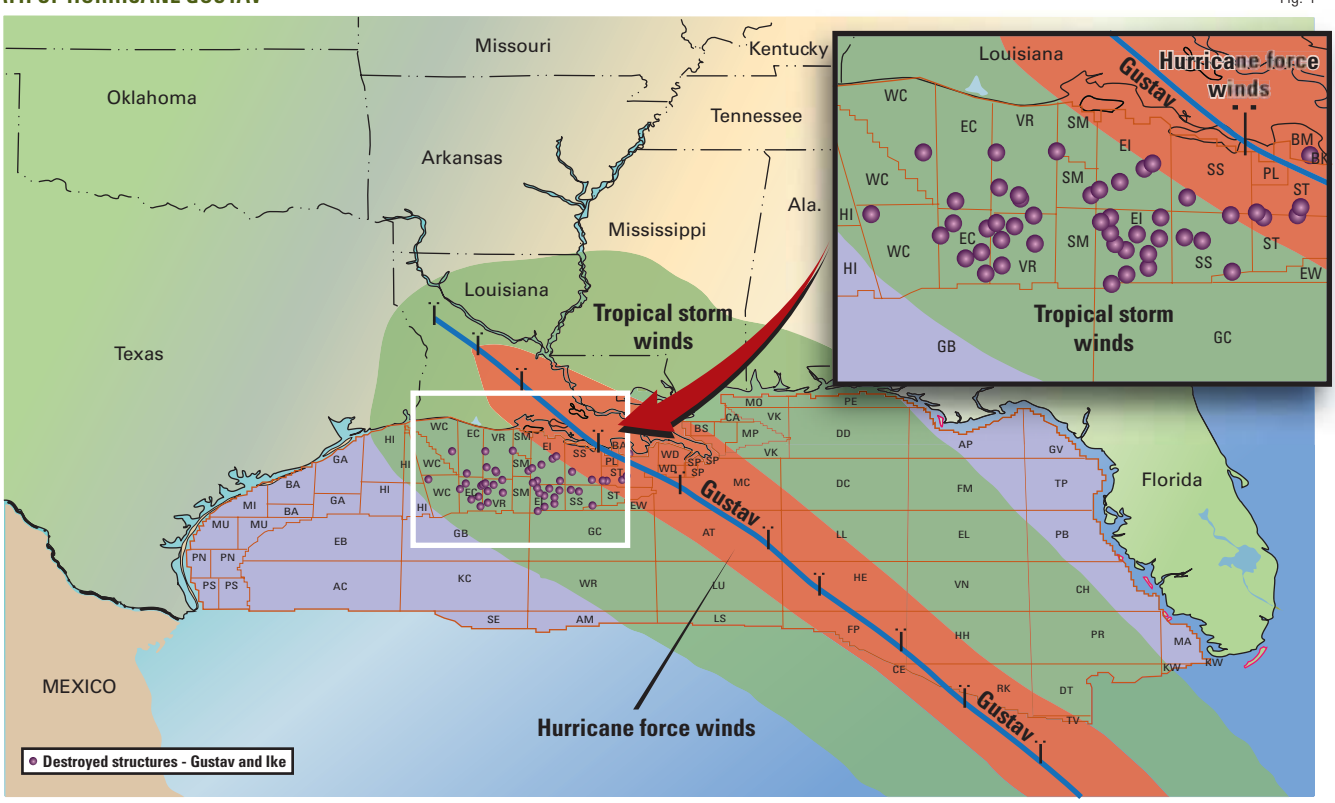
Data source

Following every major hurricane, the MMS issues Notices to Lessees (NTLs) that require platform owners to perform above and below water inspections of infrastructure exposed to hurricane-force winds.

For platforms exposed to hurricane-

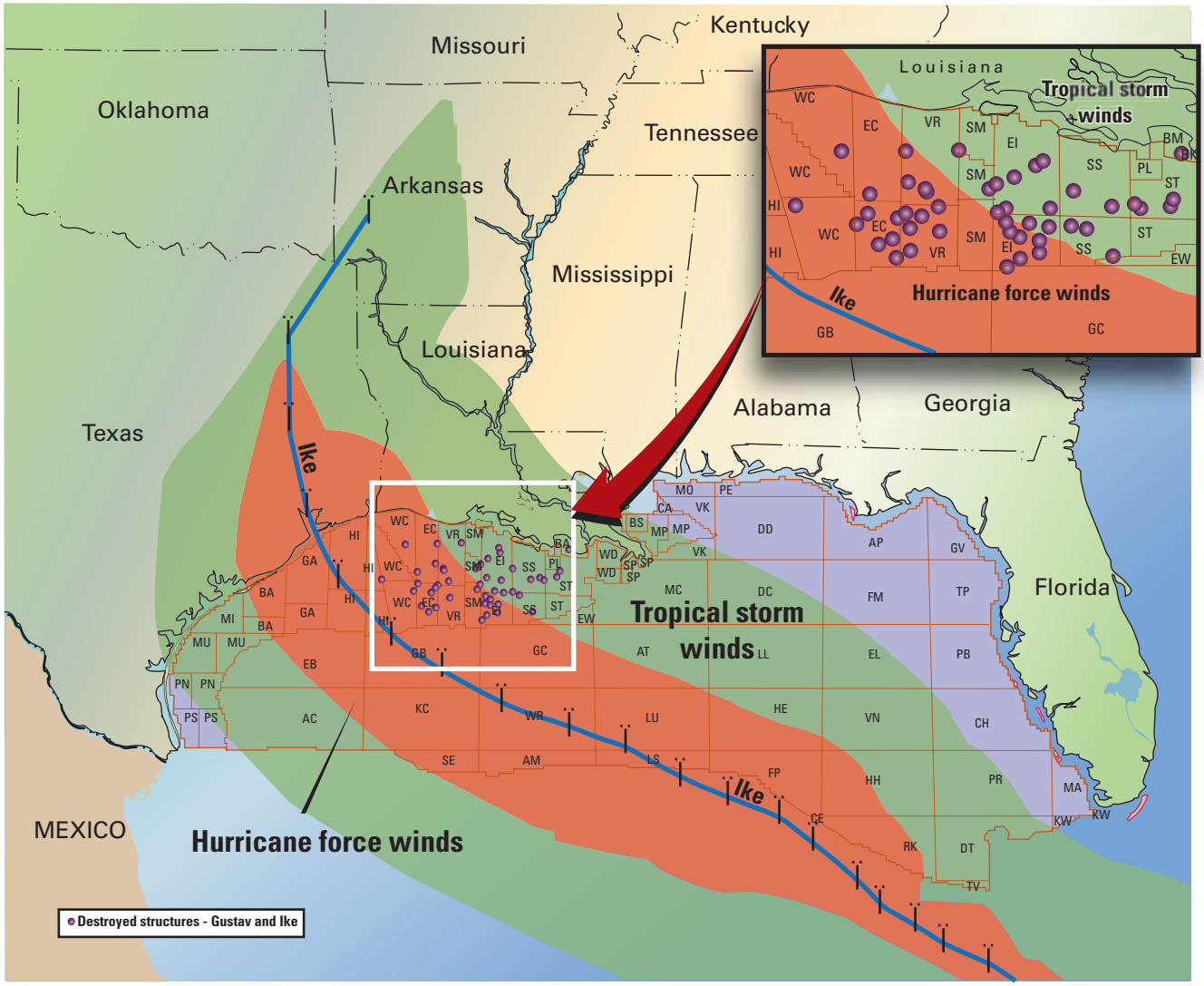
PATH OF HURRICANE GUSTAV

Fig. 4



PATH OF HURRICANE IKE

Fig. 5



force winds, MMS requires owners, in accordance with the API Recommended Practice 2A-WSD, to conduct a Level I survey (above water visual inspection) before manning. If damage occurred, MMS also may require additional surveys such as underwater visual inspection, close visual inspection of areas of known or suspected damage, or underwater nondestructive testing.

Platform owners report the inspection results to MMS and indicate if platforms had no damage, incurred minor or major damage, or were destroyed.

The MMS coordinates with the platform owners who report on their assessment on a periodic basis. The MMS final official list reports the total number of damaged and destroyed platforms by category. Our analysis used these public data.[1]

The number of platforms declared destroyed usually increases over time, but upon release of the final official list, typically 8-12 weeks after the event, platform owners have finished most of their damage assessments.[2,3] The data set still may be incomplete when MMS releases the official list because a platform owner may require additional time to determine the economics of replacing the structure or it may uncover additional damage to the structure overlooked in the initial inspection.

An owner also may remove a structure if a pipeline or platform that was part of the operation scheme is no longer in service or removed from service later.

Destroyed structures

Offshore structures have designs that meet the environmental conditions in which they operate. The platforms have an extremely good day-to-day operational safety record and historically have met an acceptable rate of failure.

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Abstracts are due by October 16, 2009.

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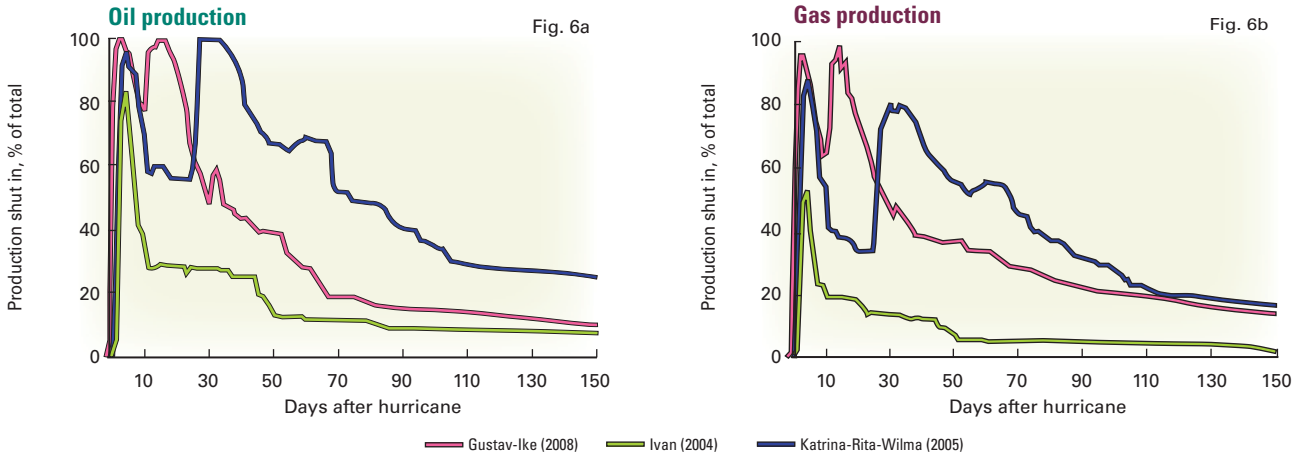
SHUT IN PRODUCTION

Fig. 6



storm or hurricane, however, the risks of damage and destruction increase dramatically because structures must sustain wind speeds, wave forces, and potential mudslides that in extreme circumstances may equal or exceed their design capacity.

Old structures in particular are vulnerable because they have designs usually with lower environmental criteria than current designs. A wave crest hitting a platform deck creates very large loads that likely will damage and in some cases collapse a platform. A key ingredient for a platform to survive a hurricane is for the deck to have an elevation above the largest hurricane waves.

Platform owners must decommission destroyed structures for removal. The work is challenging and needs to be undertaken in a way that ensures no harm to people, property, or the environment.[4]

Decommissioning costs of destroyed structures often are 5-25 times more than conventional abandonment. Likewise, risks are much greater.

Decision-making economics

If the estimated value of remaining reserves exceeds the expected cleanup and redevelopment cost, companies likely will redevelop the field. The field has little or no exploration risk, and for a young field, higher production rates are possible. These higher rates may help offset the capital expenditures of the redevelopment.

Companies likely will redevelop assets capable of producing at high rates or having more remaining reserves because these will have better economics than fields with low production rates or fewer reserves. In some cases, new drilling opportunities may arise that will improve the redevelopment economics.

A rational operator would not spend more than the estimated value of remaining reserves to replace a destroyed structure or repair a damaged structure.

Fields early in their lifecycle likely will support the production rates and reserves necessary for redevelopment. Mature assets and small producers are least likely to meet the economic thresholds, and in most cases, will face abandonment.

Companies make all decisions on a case-by-case basis on criteria such as cost information, reservoir formations, redevelopment opportunities, and other proprietary data generally unavailable in the public domain.

The decision to repair, replace, or decommission damaged and destroyed infrastructure is often difficult because of the uncertainty involved in estimates. The return on investment that a company expects to receive depends upon future production rates and hydrocarbon prices, as well as on the cost to clean up and redevelop the site.

Under normal circumstances, redevelopment decisions are no different from an initial development decision, but in the case of destroyed or severely damaged assets, companies need to account for additional complications and uncertainties regarding the procedures and costs. They have to weigh all costs against the potential revenue generating capability expressed through the remaining reserves, expected production levels, and future prices.

Production classification

One can classify offshore structures in different ways, but using the physical aspects of the infrastructure and the characteristics of the production stream is the most common.

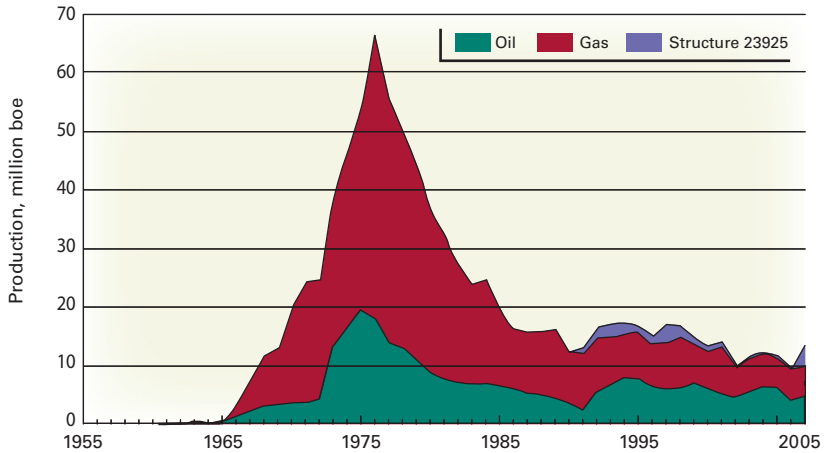
An active structure is one that produces any amount of oil or gas during the year, while an idle structure is one that once produced hydrocarbons but has had no production for at least 1 year.

Auxiliary structures are structures that never have had production and serve in a support role such as a storage, compression, or metering facility.

GOR is a common means for classifying reservoir fluids and field production. We classify oil-producing struc-

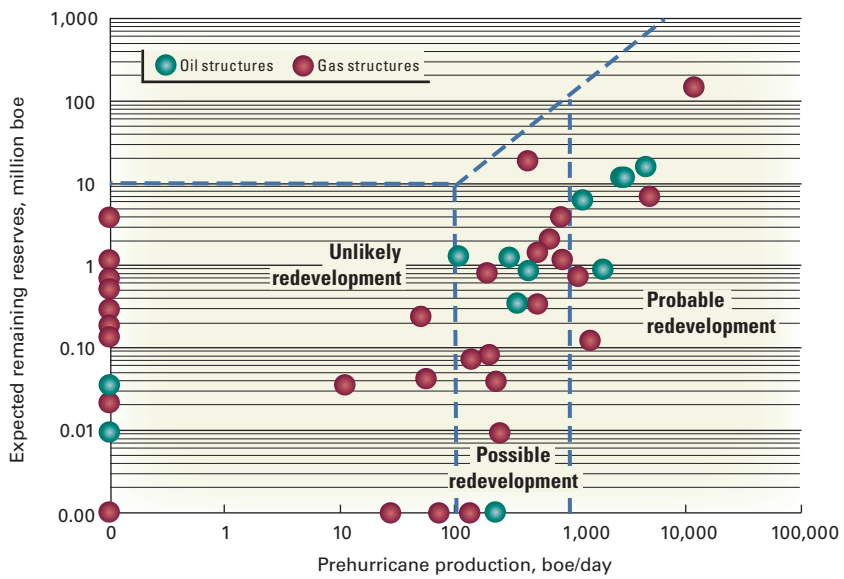
Destroyed structure historic production

Fig. 7



Redevelopment opportunity matrix

Fig. 8



Redevelopment opportunity matrix includes (1) unlikely, (2) possible, and (3) probable redevelopment.
The estimated probability of occurrence in each quadrant is $0.10 \le p(1) \le 0.20$, $0.40 \le p(2) \le 0.60$, $0.85 \le p(3) \le 0.95$.

tures as ones that produce with a GOR less than 5,000 scf/bbl. Gas structures are those producing with a 5,000 scf/bbl or greater GOR.

The units for the combined oil and gas production are in barrels of oil equivalent based on heat content (1 bbl = 6 Mcf).

Shut-in production

Figs. 6a and 6b depict the shut-in oil and gas profiles in recent storms as a percent of daily production at the time of the event. Shut-in curves may have more than one peak depending on the timing of successive events. If a second storm enters the gulf before operators assess damage or restart production, then the shut-in curve will have two peaks.

In 2005, Katrina, Rita, and Wilma occurred in quick succession, and the shut-in profile has three distinct bumps. In 2008, Ike followed Gustav within 2 weeks.

The speed of the approaching storm and collective operator response determines the upward slope of the shut-in curve. The storm's impact on the offshore and coastal infrastructure determines the downward slope and the speed at which the curves approach the origin.

If the storm destroys much infrastructure (structures, pipelines, gas processing facilities, and refineries), production will remain offline and the shut-in curve will not return to the origin during the period sampled.

If the storm causes no damage to offshore infrastructure or onshore gas processing plants and refineries, then shut-in production will approach zero and operations will resume without loss of production.

The term "lost production" refers to production associated with destroyed structures that companies plan not to redevelop.

Hurricane impact

MMS's final tally listed 60 structures destroyed by Hurricanes Gustav and Ike. Of these, one-third (20) were idle, meaning that they had no production on them for at least 1 year before the hurricanes. Nine structures never had production and are auxiliary, nonproducing structures.

Companies are unlikely to redevelop idle structures because in most cases they have extracted all the commercial reserves at the site and will schedule decommissioning of these structures when the lease stops producing.

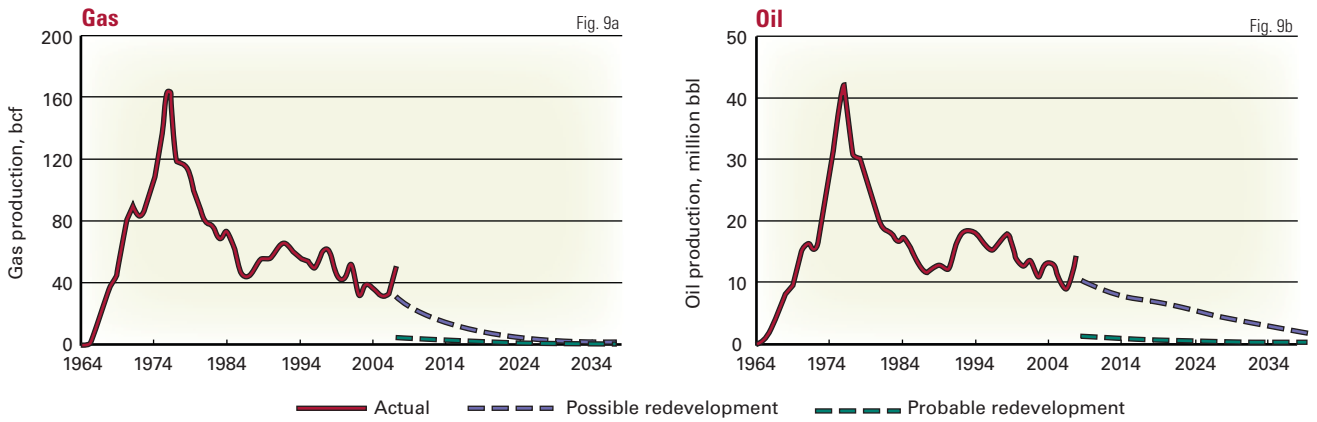
The nine auxiliary structures served in a nonproducing role and depending on the facility requirements and redevelopment options, companies may or may not reinstall them.

Fixed platforms producing gas were the most common structure destroyed (Table 1). About 60% of these structures were 25 years or older (Table 2).

We classify as idle structures, the structures without any producing wells

PRODUCTION POTENTIAL

Fig. 9



Production potential of destroyed structures assumes companies undertake all possible and probable redevelopment opportunities.
Realized redevelopment likely will include 40-60% of the possible and 90% of the probable opportunities; thereby reducing the profiles shown.

in 2007 since these structures did not have any production in 2006.

Idle age is the time since last production. For our list of destroyed idle structures, the average idle age was 7.8 years.

Half of active structures have two wells or fewer producing.

Our estimate is that the 76 oil and 74 gas wells shut in produced 15,446 bo/d and 136.58 MMcfd of gas, or 1.59% of the oil and 2.54% of the gas produced in the gulf.

Our daily production estimates differ from the MMS estimates of 13,657 bo/d and 96.49 MMcfd.[1]

Production, revenue statistics

Table 3 presents the average prehurricane daily production and revenue based on calculated production 1 year before each hurricane and normalized on a daily basis.

For calculating the average daily and annual revenues, we used monthly average oil and gas prices reported by the Energy Information Administration and then adjusted them based on the consumer price index through August 2008.

We did not adjust prices for quality differences in gravity and sulfur content, or applied a location differential to estimate netback prices.

The estimated revenue from the 31 producing structures is $2.1 million/day or $753 million/year. Table 4 summarizes daily production.

Composite production profiles

Fig. 7 shows the aggregated oil and gas production profiles for all structures destroyed by Gustav and Ike. The aggregation leaves out production from McMoRan Exploration Co.'s 23925 structure, shown separately, because the company will likely redevelop the sizable remaining reserves.

We estimated the remaining reserves and associated discounted gross revenue under constant future price scenarios and a discount rate of 10% for each asset. Production models specific to each structure estimated remaining reserves using a combination of forecast methods and heuristic techniques. Discounted revenue calculations assumed first revenue would occur 1 year after initial investment.

Table 5 presents reserves as a range based on future prices that vary from $60 to $140/bbl. Remaining reserves estimates show varying degrees of sensitivity to changes in future prices depending on the age of the asset and nature of the production profile, but in aggregate, the amount of variability is unremarkable because of the assumption that after redevelopment companies will expend no additional capital to increase or enhance production.

For several assets (Structures 305, 927, 1286, 21009, and 23009), initial revenue fell below the structure's revenue threshold or economic limit, and therefore future production is not commercial and depicted as zero.

It is possible that companies may identify additional targets at these sites or redevelop them in conjunction with nearby fields, but such information was unavailable for analysis.

Discounted revenues increase significantly with changes in future prices. The analysis aggregates remaining reserves estimates and discounted gross revenue using three categories for redevelopment: unlikely, possibly, and

HURRICANES GUSTAV, IKE DESTROYED STRUCTURES

Table 1

Production type	Caisson	Well protector	Fixed platform	Total
Oil	1	2	14	17
Gas	1	2	31	34
Total	**2**	**4**	**45**	**51**

Source: Minerals Management Service

STRUCTURES DESTROYED

Table 2

Complex/ structure	Operator	Area	Block	Structure type	Prod. type	Depth, ft	First year on prod.	Last year on prod.	Total number of drilled wells	Total no. of producing wells in 2007	Cumulative prod. Oil, 1,000 bbl	Cumulative prod. Gas, bcf	Cumulative prod. Million boe
305	Energy Partners Ltd.	VR	320	Fixed	Gas	207	1999	2007	4	1	8.5	6.3	1.1
626	Energy XXI GOM LLC	WC	248	Caisson	Gas	80	2000	2002	1	0	0.2	0.9	0.1
806	ERT GOM Inc.	EC	364	Fixed	Gas	373	2000	2007	6	3	170.5	10.2	1.9
927	Merit Energy Co.	EI	288	Fixed	Gas	202	2001	2007	1	1	24.5	5.2	0.9
1055	W&T Offshore Inc.	EI	397	Fixed	Gas	472	2002	2007	19	13	4,269.60	32.5	9.7
1286	Sterling Energy Inc.	EI	268	WP	Gas	190	2003	2007	1	1	3.5	1.6	0.3
1340	Bois D'Arc Offshore Ltd.	VR	122	Fixed	Gas	76	2004	2007	3	3	307.3	11.4	2.2
20068	Mariner Energy Inc.	EI	292	Fixed	Gas	210	1970	2007	17	5	209.6	448	74.9
20135	Conn Energy Inc.	EC	229	Fixed	Gas	115	1972	2005	12	0	0.1	9.3	1.5
20524	Samson LLC	VR	217	Fixed	Gas	121	1967	2005	14	0	572.5	36.9	6.7
20556	Stone Energy Corp.	VR	267	Fixed	Gas	169	1973	2005	12	0	1,641.90	113.8	20.6
20732	Stone Energy Corp.	VR	131	Fixed	Gas	57	1967	2005	2	0	769.7	73.5	13
20739	Apache Corp.	EI	296	Fixed	Gas	214	1973	2007	26	2	7,721.20	276.2	53.8
20940	Chevron USA Inc.	EC	272	Fixed	Gas	182	1973	2005	12	0	4,630.50	126	25.6
20947	McMoran Oil & Gas LLC	SM	49	Fixed	Gas	98	1966	2007	12	7	4,058.80	362.8	64.5
21008	Shell Offshore Inc.	EI	331	Fixed	Gas	246	1972	2003	30	0	26,016.10	170.3	54.4
21009	McMoran Oil & Gas LLC	EI	179	Fixed	Gas	96	1969	2007	7	1	1,112.40	124.5	21.9
21215	Mariner Energy Inc.	EI	266	Fixed	Gas	167	1970	2005	14	0	162.4	226.8	38
21463	Maritech Resources Inc.	SM	48	Fixed	Gas	107	1966	2005	7	0	1,046.70	148.1	25.7
21471	Beryl Oil and Gas LP	ST	196	Fixed	Gas	105	1971	2007	10	2	5,991.80	111.9	24.6
21579	Devon LP	EI	330	Fixed	Gas	244	1973	2007	39	9	38,320.80	384.4	102.4
21764	Stone Energy Corp.	EC	281	Fixed	Gas	175	1976	2007	13	2	1.3	169.1	28.2
21768	Ncx Company LLC	EI	349	Fixed	Gas	320	1975	2002	44	0	8,356.30	266.3	52.7
22012	Stone Energy Corp.	VR	329	Fixed	Gas	220	1979	2005	10	0	1	86.8	14.5
22248	Merit Energy Co.	VR	386	Fixed	Gas	324	1981	2001	14	0	3,191.90	53.6	12.1
22343	Mariner Energy Inc.	EI	267	Fixed	Gas	176	1981	2007	11	2	51.5	62.8	10.5
22444	Beryl Oil and Gas LP	ST	195	Fixed	Gas	100	1981	2007	11	1	178.2	105.7	17.8
23098	SPN Resources LLC	EC	330	Fixed	Gas	255	1985	2007	8	2	1,210.10	21.8	4.8
23308	W&T Offshore Inc.	EI	371	Fixed	Gas	415	1989	2007	24	4	3,229.00	79.8	16.5
23925	McMoran Oil & Gas LLC	EW	947	Fixed	Gas	477	1990	2007	30	11	5,594.20	109.5	23.8
26044	Apache Corp.	SS	291	WP	Gas	235	1994	2007	2	1	98	23.8	4.1
29049	Apex Oil & Gas Inc.	WC	473	Fixed	Gas	130	1996	2006	1	0	6.9	6.5	1.1
80003	Walter Oil & Gas Corp.	EI	390	Fixed	Gas	350	1997	2007	3	1	26.1	39.3	6.6
90004	St Mary Land Exp. Co.	VR	281	Fixed	Gas	176	1997	2007	9	2	820.2	18	3.8
1038	Energy Resource Technology GOM Inc.	EI	302	Fixed	Oil	224	2002	2007	5	4	2,735.70	9.5	4.3
20330	Apache Corp.	EI	175	Fixed	Oil	85	1966	1984	12	0	9,378.70	11.3	11.3
20530	Century Exploration Inc.	SS	154	Fixed	Oil	62	1955	2000	20	0	11,233.60	12.3	13.3
20565	Energy XXI GOM LLC	ST	21	Fixed	Oil	41	1962	1978	2	0	373	0.6	0.5
20670/1	Chevron USA Inc.	EC	272	Fixed	Oil	188	1973	2007	15	3	16,544.90	17.7	19.5
20670/3	Chevron USA Inc.	EC	272	Fixed	Oil	188	1973	2007	16	5	10,879.80	28.3	15.6
20737	SPN Resources LLC	SS	253	Fixed	Oil	187	1967	1979	8	0	986	4.4	1.7
20810	Devon Energy Production Co. LP	EI	119	Fixed	Oil	37	1962	1990	1	0	1,712.90	1.4	1.9
20832	Devon LP	EI	125	Fixed	Oil	40	1972	2004	2	0	799.7	1.3	1
21031	Devon LP	EI	330	Fixed	Oil	254	1973	2007	39	19	72,469.60	118.6	92.2
21583	Chevron USA Inc.	EI	339	Fixed	Oil	260	1973	2007	44	16	32,889.40	69.2	44.4
21781	Unocal Pipeline Co.	SS	208	Fixed	Oil	97	1964	2007	10	2	11,459.10	53.8	20.4
21795	Chevron USA Inc.	EI	339	Fixed	Oil	268	1975	2007	27	6	6,084.10	12.3	8.1
23009	Chevron USA Inc.	EC	272	Fixed	Oil	185	1985	2007	10	2	1,793.50	8.1	3.1
23370	Apache Corp.	VR	284	Fixed	Oil	186	1991	2007	8	5	10,320.60	12.6	12.4
23974	Nexen USA Inc.	EI	258	WP	Oil	155	1992	2002	2	0	2,355.10	6.1	3.4
27008	Maritech Resources Inc.	EC	328	Fixed	Oil	243	1995	2007	28	14	3,896.20	9.8	5.5
Total									**678**	**150**	**315,715.20**	**4,101**	**998.9**

Note: WP = well protector.

most likely.

Companies likely will decommission structures with production of fewer than 100 boe/d, may redevelop structures with production between 100-1,000 boe/d, and likely will redevelop structures with production of more than 1,000 boe/d.

We selected these cutoff values from historical data based on the redevelopment rates of previous hurricane events.

At $60/bbl oil, companies may redevelop 31 millon boe and likely redevelop 201 million boe with discounted values of $677 million and $4.0 billion (Table 5).

At $100/bbl oil, companies may redevelop and most likely will redevelop reserves equal to $1.1 billion and $6.7 billion, respectively.

Redevelopment potential

Redevelopment strategies available to companies are site-specific. It is difficult or impossible to assemble many relevant factors such as the geologic conditions of the reservoir and drilling opportunities available, cleanup and redevelopment cost, and strategic decisions.

Fortunately, there are many other accessible factors with a reasonable degree of accuracy, such as production and drilling profiles and lease inventories.

Estimates of remaining reserves and valuations have a larger degree of uncertainty.

When a storm destroys a producing structure, most wells require abandonment. Depending on the lease infrastructure and processing and transportation options available, the operator may replace the structure and drill new wells. The operator may replace a structure at the original site or elsewhere on the lease or an adjacent lease, depending on field configuration.

A company may base the decision to redevelop on factors such as expected posthurricane production potential, estimated remaining reserves, probability of success, and cost of cleanup and redevelopment.

Our analysis assumes that prehurricane production provides a reasonable, first-order indicator of expected redevelopment potential. Estimated remaining reserves have a reasonable degree of certainty, while cleanup and redevelopment cost are unknown and uncertain. For each destroyed structure, we have plotted prehurricane production rates and expected remaining reserves (Fig. 8).

Each destroyed structure is a candidate for redevelopment and is unique in its production capacity and damages incurred. Idle structures fall on the vertical axis and are unlikely to be redeveloped.

Structures with positive prehurricane production rates and zero expected remaining reserves arise from modeling a structure's entire production lifecycle and may or may not be redeveloped. Our working assumption is that companies are more likely to redevelop structures with large prehurricane production rates and remaining reserves.

We classify regions as redevelopment unlikely, possible, and probable and assign probabilities of occurrence to each region.

We base the estimated probability of redevelopment on previous hurricane events (Ivan, Katrina, and Rita). The ranges are 10-20% unlikely, 40-60% possible, and 80-90% probable.

Companies are unlikely to restart structures in the left most quadrant because the projects will have both low cash flows and low valuations. Structures residing in the possible and probable redevelopment regions have a greater likelihood of returning the capital expenditures required by the investment.

In the middle quadrant, where prehurricane production rates range from 100-1,000 boe/d and expected remaining reserves generally range from 10,000 to 20 million boe, structures have about a 50:50 chance of redevelopment.

Our analysis calculates expected remaining reserves by multiplying the reserve estimates by the anticipated redevelopment rates (pi), where i = 1, 2, 3 per category assumed, for instance p1 = 15%, p2 = 50%, and p3 = 90%.

The calculation for the expected value of the redevelopment opportunities assigns a probability vector to future prices. If (q1, q2, q3, q4) = (0.35, 0.35, 0.20, 0.10) corresponds to future price expectations of ($60/bbl, $80/bbl, $100/bbl, and $120/bbl), then E(P) = $74/bbl. Table 6 summarizes the expected value of gross revenue, E(REV).

Figs. 9a and 9b show the oil and gas production forecast for the collection of producing structures classified according to possible and probable redevelopments.

Our results are sensitive to the redevelopment of structure 23925 that is responsible

Structures statistics in 2007

Table 3

Complex/ structure	Production type	Production[1] Oil, b/d	Gas, Mcfd	boe/d	Daily revenue,[2] $	Annual revenue,[2] $1,000
305	Gas	0	162	27	1,070	391
806	Gas	13	1,056	189	7,971	2,910
927	Gas	1	420	72	2,891	1,055
1055	Gas	869	23,402	4,770	220,084	80,331
1286	Gas	2	775	131	5,246	1,915
1340	Gas	102	6,133	1,124	48,248	17,611
20068	Gas	1	4,843	809	32,134	11,729
20739	Gas	34	2,808	502	21,116	7,707
20947	Gas	52	8,306	1,437	58,874	21,489
21009	Gas	3	1,434	242	9,728	3,551
21471	Gas	124	576	220	13,120	4,789
21579	Gas	517	1,890	832	51,337	18,738
21764	Gas	0	1,120	187	7,409	2,704
22343	Gas	0	300	50	1,984	724
22444	Gas	0	62	11	444	162
23098	Gas	166	2,005	501	25,763	9,404
23308	Gas	112	1,837	418	20,562	7,505
23925	Gas	1,922	55,829	11,227	513,657	187,485
26044	Gas	4	310	55	2,333	851
80003	Gas	1	3,820	637	25,330	9,245
90004	Gas	121	102	138	9,796	3,576
1038	Oil	1,165	4,346	1,889	116,234	42,425
20670/1	Oil	376	300	426	30,210	11,027
20670/3	Oil	232	355	291	19,770	7,216
21031	Oil	3,752	4,310	4,471	310,366	113,283
21583	Oil	2,113	4,658	2,889	189,527	69,177
21781	Oil	37	421	107	5,574	2,035
21795	Oil	1,137	734	1,260	90,278	32,951
23009	Oil	0	1,337	223	8,866	3,236
23370	Oil	283	346	341	23,562	8,600
27008	Oil	2,305	2,588	2,736	190,240	69,438
Total		**15,446**	**136,584**	**38,210**	**2,063,723**	**753,259**

[1]Computed 1 year prior to the hurricane events and normalized on a daily basis. [2]Computed 1 year prior to the hurricane events based on monthly EIA oil and gas prices and CPI-adjusted through August 2008.

Daily production

Table 4

Prehurricane production, boe/d	Oil	Gas	All
<100	0	5	5
100-250	2	6	8
250-500	3	1	4
500-1000	0	5	5
1,000-2,500	2	2	4
2,500-5,000	3	1	4
5,000-10,000	0	0	0
>10,000	0	1	1
All	**10**	**21**	**31**

ACTIVE STRUCTURE ESTIMATED REMAINING RESERVES, REVENUES

Table 5

Complex/ structure	Remaining reserves, 1,000 boe, $60-140/bbl	Discounted revenue at 10%, $1,000 $60/bbl	$80/bbl	$100/bbl	$120/bbl	$140/bbl
305	0-0	0	0	0	0	0
806	63-81	2,093	2,790	4,329	5,195	6,060
927	0-0	0	0	0	0	0
1055	6,910-6,927	187,857	250,594	313,242	375,891	438,539
1286	0-0	0	0	0	0	0
1340	697-708	21,021	28,271	35,339	42,407	49,475
20068	3,763-3,924	70,759	94,561	118,352	142,062	165,809
20739	243-386	6,904	10,601	13,960	17,327	20,668
20947	91-135	2,659	4,124	5,405	6,722	8,058
21009	0-23	0	0	517	1,088	1,684
21471	39-46	1,627	2,169	2,711	3,724	4,345
21579	1,050-1,139	29,759	40,254	50,745	61,067	71,401
21764	745-844	15,427	20,912	26,313	31,717	37,114
22343	170-270	4,458	6,845	9,014	11,189	13,347
22444	15-43	508	1,132	1,813	2,520	2,941
23098	1,347-1,463	31,957	42,998	53,944	64,892	75,777
23308	18,797-18,884	391,749	522,346	652,939	783,533	914,124
23925	146,956-147,042	2,553,676	3,404,902	4,256,129	5,107,355	5,958,581
26044	0-54	0	1,090	2,234	2,680	3,907
80003	1,946-2,107	38,361	51,530	64,677	77,684	90,755
90004	64-79	2,716	4,040	5,049	6,442	7,515
1038	881-881	36,287	48,383	60,478	72,574	84,670
20670/1	825-896	25,203	33,910	42,543	51,178	59,763
20670/3	1,201-1,293	31,211	41,875	52,477	63,080	73,678
21031	16,094-16,152	427,729	570,317	712,902	855,488	998,073
21583	11,936-11,995	315,107	420,158	525,206	630,254	735,301
21781	1,135-1,362	17,481	23,356	29,208	35,056	40,901
21795	6,043-6,100	143,825	191,786	239,755	287,717	335,675
23009	0-0	0	0	0	0	0
23370	317-375	11,785	16,199	20,643	24,944	29,398
27008	11,723-11,776	301,059	401,427	501,791	602,155	702,517
Subtotal-A	185-366	4,966	9,067	13,061	16,389	20,195
Subtotal-B	31,536-32,901	677,032	907,539	1,138,408	1,368,988	1,598,993
Subtotal-C	201,330-201,716	3,989,219	5,319,962	6,650,248	7,980,563	9,310,890
Total	**233,051-234,983**	**4,671,216**	**6,236,569**	**7,801,717**	**9,365,940**	**10,930,077**

Note: Remaining reserves correspond to oil prices that range from $60/bbl to $140/bbl. Revenue computed based on the assumption that first revenue occurred 1 year after initial investment. Structures with no remaining reserves are uneconomic at the time of the assessment. Subtotal A computed from all structures with prehurricane production less than 100 boe/d and designated as unlikely to be redeveloped. Redevelopment rates from this class are estimated at 10-20%. Subtotal B computed from all structures with prehurricane production greater than 100 boed and less than 1,000 boe/d designated as a possible redevelopment opportunity. Only a percentage of these reserves are likely to be recaptured in the future, estimated at 40-60%. Subtotal C computed from structures with prehurricane production greater than 1,000 boe/d and are considered highly likely to be redeveloped. Most of these reserves are likely to be recaptured, estimated at 90% or greater.

GROSS REVENUE EXPECTED VALUE

Table 6

Scenario	$60/bbl	$80/bbl	$100/bbl	$120/bbl	E(P), $/bbl	Expected value of gross revenue, billion $
1	0.70	0.10	0.10	0.10	72	14.2
2	0.50	0.30	0.10	0.10	76	15.0
3	0.40	0.20	0.20	0.20	84	16.6
4	0.35	0.35	0.20	0.10	81	16.0
5	0.25	0.25	0.25	0.25	90	17.8
6	0.10	0.20	0.35	0.35	99	19.6
7	0.20	0.20	0.20	0.40	96	19.0
8	0.10	0.10	0.30	0.50	104	20.5
9	0.10	0.10	0.10	0.70	108	21.3

for more than half of the total production potential. ✦

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LOW CO_2 SLIP—Conclusion

Low CO_2 slip in high-pressure MDEA systems investigated

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This article concludes a two-part series that presents experience in 2008 with various marketed process simulators modeling Suncor's 85-MMscfd Simonette sour-gas plant in northwestern Alberta. This experience showed that predicted results differed widely from actual operating conditions.

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

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

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

Simulator comparisons

Simulation results were compared to field data at the Simonette plant for:

- CO_2 slip.
- Temperatures (selected absorber and stripper trays, stripper overhead, and boil-up).
- Lean-amine loadings (stripper performance).
- Sweetened gas H_2S compositions.

Further comparisons were made to actual equipment heat exchanger duties; the accompanying table lists the results from process simulator Nos. 2 through 5.

Based on the comparison of simulators used, as noted in the table, Simulator 2, Case 2d-2 appeared to provide the closest matching field results. A subsequent smaller study looked at the effects of varying certain parameters using the baseline case.

Fig. 1 shows certain parameter variance to the effects of H_2S in the treated gas, CO_2 slip, and clear liquid residence time (CLRT, discussed in Part 1). Many other studies were performed, such as varying the inlet temperature, lean-amine temperature, amine feed tray, and lowering amine strength. All produced slight variations, but none of the modeled results showed great promise for effecting changes to CO_2 slip.

During the simulation work, other solutions were experimented with to fulfill initial speculations discussed with Suncor.

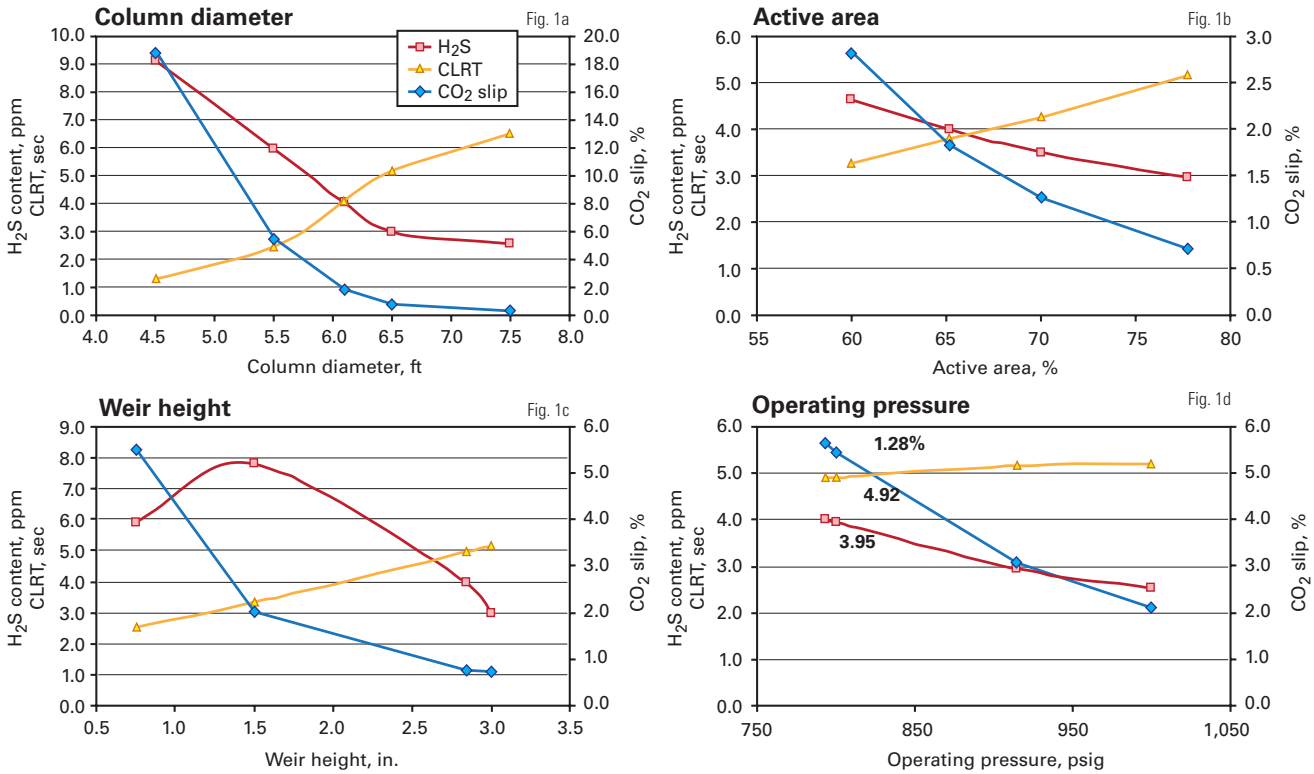
- *Packed columns.* The trayed column was substituted with packing but was not seen to yield improvements in slip.
- *Pumparounds with cooling, heating.* Pumparounds were tried around the predicted column temperature bulges both by decreasing and increasing the stage liquid temperatures. The column convergence proved to be difficult and the results obtained were marginal.
- *Case study for a process configuration with a three-stage crossflow absorption (mixer-settler configuration).* A static mixer was incorporated in the feed with a proportional amount of amine diverted that showed some favorable results. It was not determined, however, whether the configuration of a cocurrent column could model the system.

While a two-stage countercurrent contactor was implemented, it was not determined whether the settings for the ideal-real stage ratios or the tray efficiencies corresponded to accurate system behavior.

Based on the single static mixer results, a system was modeled similar in

PARAMETER VARIANCES

Fig. 1



concept to Framo Purification's three-stage contactor process,[1] shown in Fig. 2 but with some modifications.

Based on the inlet feed flow rates and gas compositions, similar lean-amine flows, and capabilities of the regeneration system, the arrangement appeared capable of slipping 98% of CO_2 while meeting H_2S specifications in the treated gas by making use of a static mixer's short residence time that appears to match the kinetic requirements.

Some additional cooling would be required as indicated by the exchangers between mixing elements.

The flow pattern in a static mixer is likely analogous to a spray regime in a column, which, while an interesting concept when applied to an absorber as maximizing CO_2 slip, is beyond the focus of this article. Suffice to say that increased slip may be realized by operating an absorber column outside of the normal range of flood.[2]

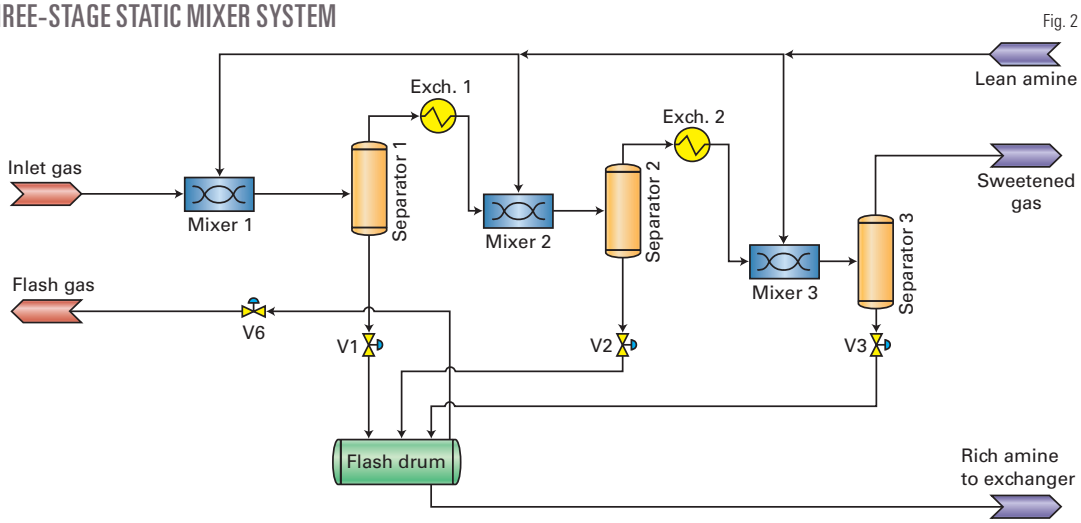
Effects of DEA

The table shows a large variance between CO_2 slip values. Why was the variance so great?

Simulator No. 2, chosen partly for modeling CO_2 slip values closest to actual plant operating data, may have inherently predicted less slip (more CO_2

THREE-STAGE STATIC MIXER SYSTEM

Fig. 2



pickup). Conversations with other researchers revealed that the particular simulator chosen for the baseline study may inherently over predict the amount of CO_2 removal.

Fig. 3 shows the results of varying selected parameters with respect to H_2S in the outlet gas and CO_2 slip, comparing the MDEA system with and without DEA.

What do the results of the study tell? According to one popular process simulator, taking out a small amount (1.4%) of DEA shows a jump in CO_2 slip, by an order of magnitude in some cases. Accompanying the CO_2 rejection, however, the simulator also predicts a worsening of H_2S concentration in the treated-gas outlet stream.

The simulation seems inconclusive, considering results from the other process simulators that either promised adequate slip, an adequate H_2S outlet-gas specification, or both.

Are the results believable?

Operating experiences

Discussions with industry people indicated a consensus that small amounts of DEA in MDEA at high pressures could cause large amounts of CO_2 pickup. A similar situation was experienced by a northern Alberta gas plant, initially slipping a high percentage of the feed CO_2. In 1994, the plant operated at about 500 psig inlet pressure, processing some 25 MMscfd feed with 3.5 mol % CO_2 and 1.5 mol % H_2S. It was initially held that a small amount of DEA added caused the slip to decrease virtually to zero.

A second gas plant in central Alberta has a system of two HP amine contactors operating in parallel at about 1,000 psig and flow rate of about 180 MMscfd of 7% H_2S and 5% CO_2 feed. This plant, which initially had about 10% CO_2 slip, went virtually to zero unexpectedly.

Upon analyzing the lean amine, the plant found it had been contaminated with small amounts of DGA and DEA thought to have come from cross contamination when the amine system had been topped up. (The concentration was suspiciously equivalent to a truckload of amine.) The CO_2 slip has not improved back to the initial design levels; in spite of replacement of lost system amine over 1½ years, the current DEA component being about 1.6%.

While the reported operating experience from two plants alone may not indicate DEA causing low slip operation, unofficial discussion with others in industry seems to substantiate this phenomenon. This led to speculation that any DEA in the mix will absorb most of the CO_2 in addition to the H_2S at high pressures.

The small amounts of DEA in solution appear to be able to pick up a disproportionate amount of CO_2 in the solution mix, leading to speculation that DEA may be acting as a shuttle mechanism within the MDEA system. Subsequent discussions with commercial amine suppliers, however, failed to reveal any proposed mechanism to account for this apparent phenomenon.

Proprietary amine blends

Many MDEA suppliers have "doctored" their products with specific additions of primary and secondary amines, making them proprietary. In many instances, lab amine testing precludes reporting certain blends and, depending who does the testing and where the results are from, may exclude these specific known blended components or else provide component data as relabeled pseudonyms.

For example, it was speculated by one amine supplier that a component NMEA or MMEA could have been present but had not shown up in previous test reports. Specific testing for that component, although mentioned possibly being present, was not subsequently shared.

SIMULATOR COMPARISONS

	Actual	Simulator 2		
		Case 1d	Case 2d	Case 2d-2
Parameter, units	Measured (design) values)	50 wt % MDEA, 0 wt % DEA	48.6 wt % MDEA, 1.4 wt % DEA, 0.16 wt H_2SO_4	48.6 wt % MDEA, 1.4 wt % DEA, 0 wt % H_2SO_4
C-520 H_2S in * (dry basis), %	3.063	3.063	3.063	3.063
C-520 H_2S out (dry basis), ppm	4.342	7.5	6.119	2.96
C-520 CO_2 in * (dry basis), %	2.033	2.033	2.033	2.033
C-520 CO_2 out (dry basis), %	—	0.093	0.013	0.015
C-520 CO_2 % Slip, %	~0.2	4.6	0.65	0.72
C-520 Tray 4 Temp, °C.	67.0	62.6	64.2	64.2
C-2-1 H_2S in * (dry basis), %	5.712	5.712	5.712	5.712
C-2-1 H_2S out (dry basis), ppm	5.22	8.04	12.90	5.47
C-2-1 CO_2 in * (dry basis), %	1.108	1.108	1.108	1.108
C-2-1 CO_2 out (dry basis), %	–	0.01757	0.00495	0.00629
C-2-1 CO_2 % Slip, %	–	1.585	0.447	0.567
C-2-1 Tray 7 temp., °C.	33.3	42.7	42.3	42.3
C-2-2 feed temp. *, °C.	94.8	94.8	94.8	94.8
C-2-2 Tray 5 temp., °C.	126.3	125.1	124.9	125.1
C-2-2 overhed temp., °C.	100	93.3	87.0	95.2
Boilup return temp., °C.	126.8	126.9	126.8	126.9
Reflux rate, cu m/day	76.9	53.4	36.5	61.5
E-2-4 duty lLean/rich exch., MMbtu/hr	(12.5)	16.9	16.5	16.5
E-2-6 duty amine cooler, MMbtu/hr	(14.21)	15.4	15.63	15.75
E-2-7 duty reboiler, MMbtu/hr	(27.0)	26.1	24.5	27.2
E-2-8 duty Condenser, MMbtu/hr	(10.2)	5.74	4.00	6.58
E-2-8 disch. Temp. cond.*, °C.	28.6	28.6	28.6	28.6
HM flow (60/40 wt % EG), cu m/day	5,956	5,539	5,207	5,780
% DEA	1.4	–	1.4	1.4
% MDEA	48.6	50.1	48.7	48.7
% H_2SO_4	0.16	–	0.16	–
C-520 rich-amine load, mol:mol	–	0.4899	0.4946	0.4949
C-2-1 rich-amine load, mol:mol	–	0.1768	0.1761	0.1762
Total rich-amine load, mol:mol	–	0.3925	0.3955	0.3957
CO_2 lean-amine loading, mol:mol	0.0004	0.0012	0.0015	0.0022
H_2S lean-amine loading, mol:mol	0.0049	0.0038	0.0035	0.0028
Total lean-amine loading, mol:mol	–	0.0050	0.0050	0.0050

Simulator 3				Simulator 4		Simulator 5		
7A	7B	7C	7D	Sim1	Sim2	Simon 1	Simon 2	Simon 3
50 wt % MDEA, 0 wt % DEA	48.6 wt % MDEA, 1.4 wt % DEA, 0.16 wt H_2SO_4	48.6 wt % MDEA, 1.4 wt % DEA, 0 wt H_2SO_4	48.6 wt % MDEA, 1.4 wt % DEA, 0.16 wt H_2SO_4 + full HSS comp	50 wt % MDEA, 0 wt % DEA	48.6 wt % MDEA, 1.4 wt% DEA	50 wt % MDEA, 0 wt % DEA	48.6 wt % MDEA, 1.4 wt% DEA	48.6 wt % MDEA, 1.4 wt % DEA, 0.16 wt H_2SO_4
3.063	3.063	3.063	3.063	3.063	3.063	3.063	3.063	3.063
3.791	0.014	0.006	0.146	2.56	3.45	1.53	1.33	1.33
2.033	2.033	2.033	2.033	2.033	2.033	2.033	2.033	2.033
0.520	0.521	0.513	0.447	0.896	0.644	0.768	0.691	0.691
25.6	25.7	25.2	22.0	44.1	31.7	37.8	34.0	34.0
65.5	66.4	66.7	67.6	82.1	86.0	62.9	63.8	63.8
5.712	5.712	5.712	5.712	5.712	5.712	5.712	5.712	5.712
5.288	0.024	0.007	0.310	3.53	3.44	2.55	2.21	2.20
1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108
0.231	0.227	0.222	0.115	0.401	0.134	0.192	0.161	0.161
20.8	20.5	20.1	10.4	36.1	12.1	17.4	14.5	14.5
43.5	43.8	43.8	44.0	43.1	43.3	43.4	43.4	43.4
94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8
124.6	124.8	124.6	124.8	122.7	122.6	126.3	126.3	126.3
90.2	111.4	114.8	92.2	112.1	111.7	107.0	107.1	107.1
126.7	127.0	126.9	126.7	124.6	124.7	126.8	126.8	126.8
31.9	214.9	350.2	41.4	310.6	305.5	139.6	143.5	143.6
17.0	17.0	16.9	17.0	14.0	13.8	18.7	18.6	18.6
16.3	16.5	16.5	16.7	11.9	12.3	11.2	11.4	11.4
24.9	44.0	58.0	26.1	48.0	48.0	30.4	31.0	31.0
3.58	22.6	36.6	4.57	31.9	31.4	14.1	14.5	14.6
28.6	28.6	28.6	28.6	28.7	28.7	28.6	28.6	28.6
N/A	N/A	N/A	N/A	10,858	10,860	7,205	7,340	7,344
–	1.4	1.4	1.4	–	1.4	–	1.4	1.4
50.1	49.1	48.8	49.1	50.1	49.2	50.0	48.5	48.4
–	0.16	–	0.16	–	–	–	–	0.16
0.4420	0.4352	0.4412	0.4392	0.563	0.575	0.428	0.434	0.435
0.1729	0.1702	0.1733	0.1719	0.163	0.166	0.174	0.174	0.174
0.3604	0.3549	0.3582	0.3582	0.409	0.420	0.349	0.354	0.354
0.0023	0.0049	0.0059	0.0049	6.9E-07	1.3E-06	8.3E-04	1.0E-03	1.3E-03
0.0031	0.000007	0.000004	0.000036	0.0050	0.0050	0.0042	0.0040	0.0037
0.0055	0.0049	0.0059	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050

One process simulator vendor told of having certain components available in the simulator provided to special customers that were unavailable to general industry, the reason being that certain amine suppliers have developed specialized kinetic variables they are unwilling to share.

Other process simulator vendors have provided certain components in their packages that are not active. For example, it was found that Piperazine was included in one of the available process simulator components but was rendered inert because the equilibrium coefficients were not included.

DEA-MDEA model

First, the box presented in Part 1 ("Basic MDEA/DEA reactions," OGJ, July 13, 2009, p. 48) is a look at the usual published MDEA/DEA chemistry. With MDEA in solution, the box shows the normal mechanism for H_2S pickup.

DEA as a secondary amine can indirectly insert CO_2 between its N-H bond, forming a carbamate via hydrolyzing first into water and bicarbonate.

The carbamate formed by this reaction is very stable, translating into more regeneration energy required (on average) for DEA in comparison with MDEA, which does not form carbamates due to its trisubstituted nature. (MDEA can only form various salts through acid-base equilibria.)

The presence of DEA in MDEA speeds up formation of bicarbonate, which otherwise has to be formed by the direct (but slow) reaction between CO_2 and H_2O, forming carbonic acid. DEA acts as a catalyst to the reaction of MDEA with CO_2.

In studying the currently accepted mechanisms for CO_2 and H_2S interaction with secondary and tertiary amines and following discussion with industry representatives and a literature search (partially listed[3,4]) for a probable mechanism to account for Simonette's zero slip, attention was focused on S_N2 reactions.

S_N2 reactions

The S_N2 reaction (also known as bimolecular nucleophilic substitution) can occur when one of the atoms bonded to carbon is weak or highly polarized (i.e., making the carbon more electrophilic), potentially rendering this atom into a good leaving group. As an example, the bond between carbon-chlorine is highly polarized; the Cl^- presents as a good leaving group because it is a stable anion in solution.

If NaOH is added into an aqueous solution of CH_3Cl, the HO^- (the nucleophile) will displace the chloride because the HO^- anion is much less

RESULTS OF SIMULATOR CASES

Fig. 3

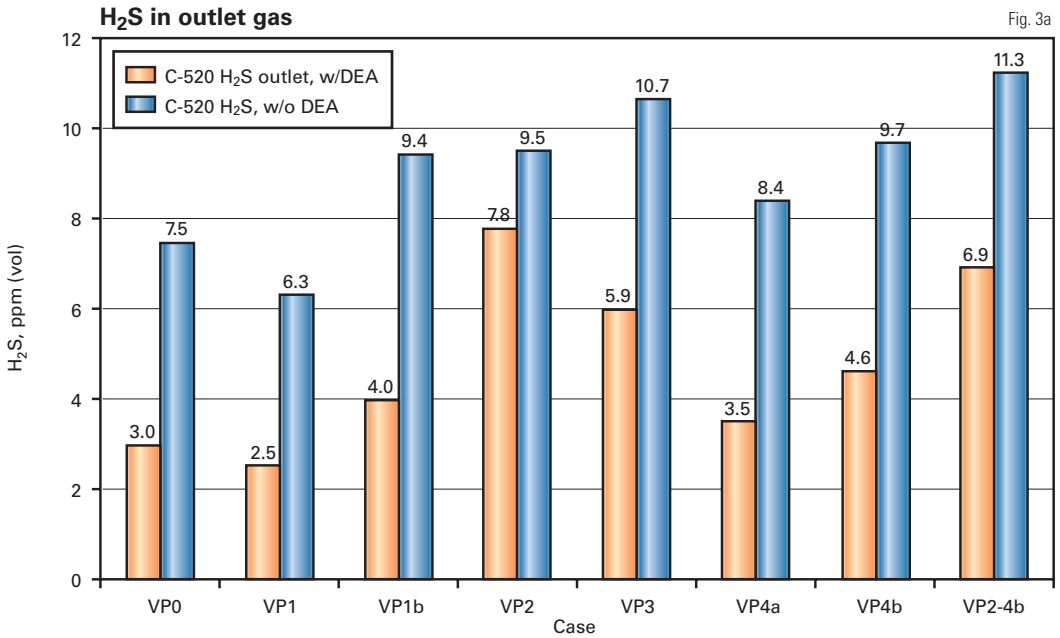


Fig. 3a

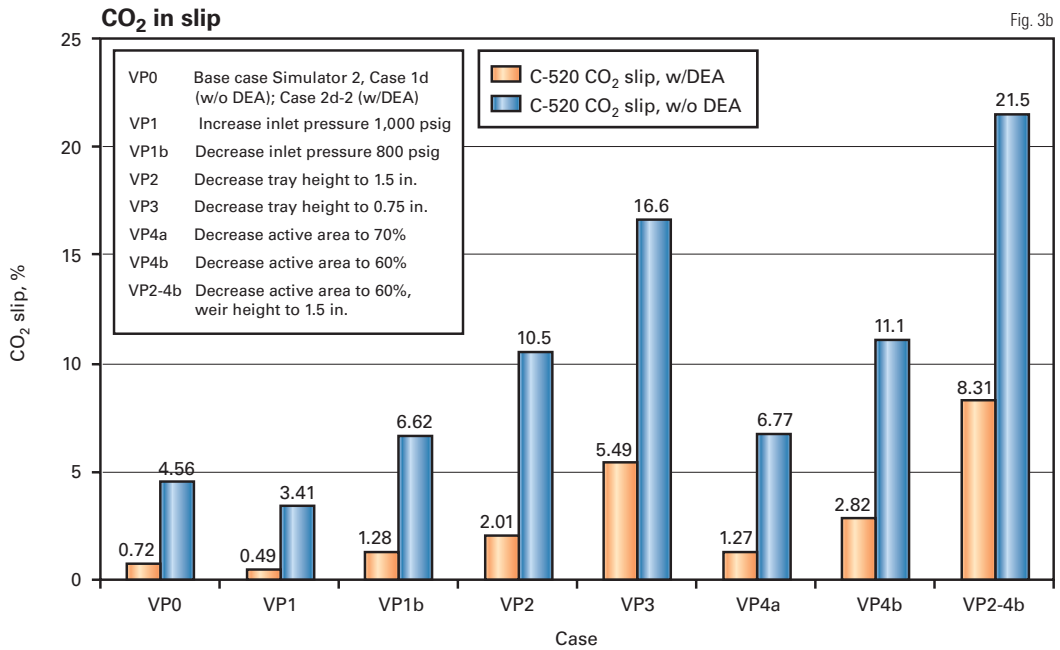


Fig. 3b

stable in solution than a chloride ion. This provides a rationale as to driving force of the reaction, in which thermodynamically more stable products are potentially made. This mechanism suggests that a probable model exists in which DEA contaminants may increase the pickup rate of CO_2 in MDEA systems.

The actual S_N2 reaction takes place in a single step as a concerted process. This involves simultaneous bond formation of the nucleophile to the carbon and bond breakage between the carbon and the leaving group. As the bond formation becomes more complete for the nucleophile, the bond breaking also becomes more complete for the leaving group.

This concerted process has an activation energy barrier that corresponds to some point along the reaction coordinate (i.e., the highest potential energy is reached at say, 50% new bond formation and 50% bond breakage).

This mechanism suggests a probable model exists in which DEA contaminants may increase the pickup rate of CO_2 in MDEA systems. MDEA and other amines used in acid-gas removal processes are basic compounds and, as such, are in equilibrium between the protonated and nonprotonated state.

In its protonated form, the C-N bond to the methyl substituent becomes more polarized and weakened. Effectively, the methyl group is made more electrophilic and subject to undergo S_N2 reaction with a nucleophile. As such, it may be that a reaction between the DEA carbamate anion as a nucleophile could occur in absorbers operating in higher pressure systems.

In this reaction, the methyl substituent of MDEA is picked up by the

carbamate to form the methyl carbamate of DEA (see product diagrams, Fig. 4), which displaces another pseudo molecule of DEA, at which point the same reaction may be repeated until no CO_2 remains.

This proposed pathway may explain why trace DEA impurities in MDEA bulk systems lead to large drops in CO_2 slip, as the DEA present acts as a CO_2 sink and is catalytic, such that each molecule of CO_2 that is trapped leads to the formation of another molecule of free (pseudo)-DEA in higher pressure systems.

When we look at the DEA-carbamate molecule reacting with a protonated MDEA molecule, the S_N2 reaction takes place at the methyl group carbon (Fig. 4b).

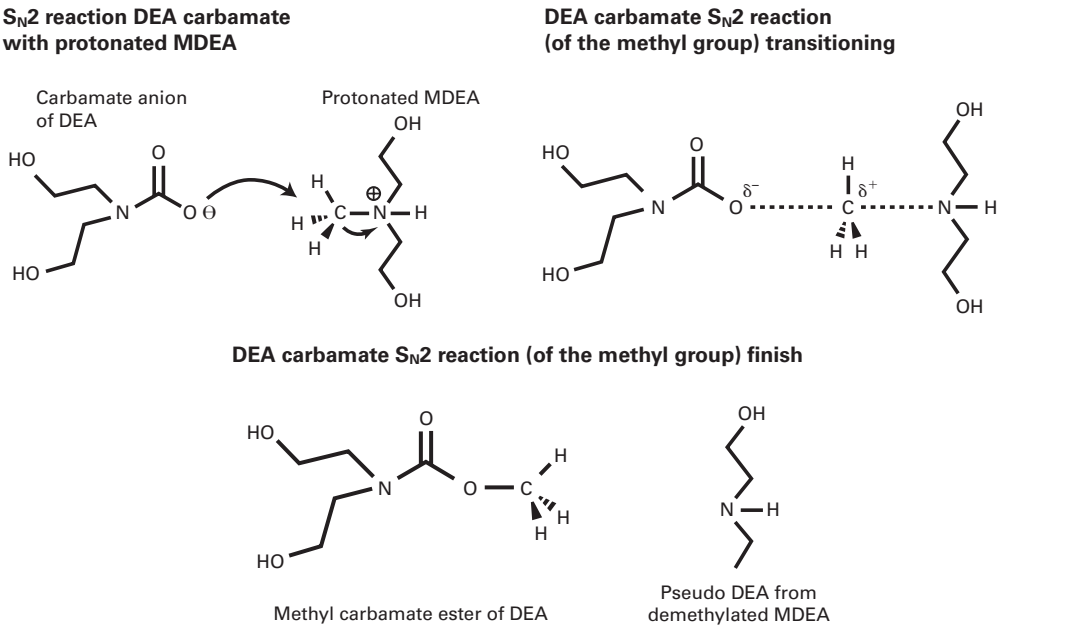
After reaction completion, the products shown in Fig. 4c would prevail.

Given a chain reaction of events starting with a small amount of DEA that quickly converted to carbamate and subsequently methylated (Fig. 4), could this provide a cascading effect of producing an unstable, pseudo-DEA capable of CO_2 pickup from the protonated (thought to be a large fraction of the solution species) of MDEA?

This would certainly help explain why CO_2 slip suddenly goes to zero when small amounts of DEA are present in solution. But large increases in the DEA component relative to MDEA of the regenerated rich amine (flowing back into the acid-gas stripper) should be detected at sampling points upstream if the process outlined were irreversible. This would most likely not be the case.

S_N2 REACTION AND RESULTING PRODUCTS

Fig. 4



At the lower pressure and elevated temperature conditions of the regenerator, which drive off acid gases, the reaction solution becomes basic again. Under these reaction conditions, the methylated DEA carbamate could become demethylated by free DEA in solution, allowing the subsequent loss of CO_2. Essentially, the regenerator would present conditions in which the favorable direction of reaction would be reversed.

In this manner, all MDEA would become regenerated, as well as the DEA impurity. Of course, without actual experimentation, the mechanism of this regeneration step is speculation and could proceed via another mechanism.

Nonetheless, the theory remains a plausible explanation for the decreased CO_2 slip phenomenon.

Acknowledgments

Special thanks to Mark Conacher in arranging permission to present the material from the Suncor Simonette plant as well as to the plant personnel Lyle Leadley and Todd Kroeker who gathered, reviewed, and forwarded the data used. Thanks also to Jacobs Canada Inc. for use of the various licensed software in performing the simulation comparisons and to Rupert Wagner, BASF, for comments provided during compilation of the earlier version of this article. ✦

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CORROSION—1

Study helps model buried pipeline pitting corrosion

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New deterministic and stochastic models can perdict the evolution of pitting corrosion depth and rate distributions from observed soil properties. Researchers performed a total of 259 excavations in 3 years gathering data that serve as the basis for these models.

Background

Recent reports place pipeline corrosion costs in Canada and the US at $7 billion/year.[1] Corrosion is the second and third leading cause, respectively, of pipeline failures in North America and Europe.[2-4] Pitting corrosion causes a higher percentage of failures than other corrosion mechanisms.

Corrosion pitting caused roughly 70% of external corrosion-related hazardous liquid spills and gas leaks in cross-country European oil and gas pipelines from the early 1970s through the mid-2000s, according to incidents reported to the European Gas Pipeline Incident Data Group (EGIG) and Conservation of Clean Air and Water in Europe (CONCAWE).[3,4] In the US, pitting corrosion caused 79% of total incidents reported to the Office of Pipeline Safety (OPS) for onshore transmission oil and gas pipelines between 2002 and 2008.[2]

In Mexico, a recent study identified about 99% of external corrosion-related incidents reported between 1994 and 2004 as pinhole-type leaks produced by corrosion pitting (OGJ, Nov. 27, 2006, p. 60).

Its high incidence has caused multiple modeling studies to focus on corrosion pitting of underground oil and gas pipelines.[5-11] Given that localized corrosion is extremely difficult to model on the basis of electrochemical reactions, statistical approaches have been used instead of electrochemical principles in developing predictive models for pitting corrosion in underground pipelines.

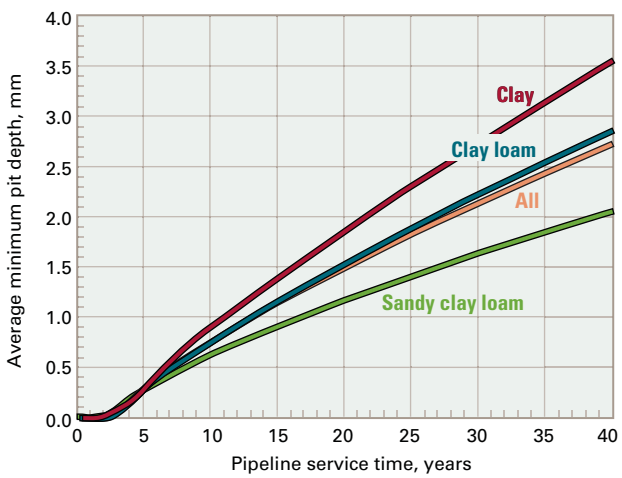
Available statistical approaches for modeling pitting corrosion use pit depth as the dependent corrosion variable and various environmental factors as the independent (predictor) variables.[5-9] Three key elements underlie these models: the law governing the time dependence of pit depth, the data available on environmental factors, and the model used to correlate the measured pit depth to these factors.

Despite the scientific and technical progress in modeling pitting corrosion in underground pipelines, several issues relevant to this damage mechanism remain and should be properly addressed. The need for more accurate predictive models for pit growth fully based on pipeline and soil characteristics, the need for a better understanding of the statistical properties of pitting depth and rate distributions, and the need for holistic approaches exploiting the symbiosis between the deterministic and stochastic models describing pipeline corrosion-pitting in soils all continue to guide pipeline engineers.

This article summarizes the results of recent study aimed at addressing these

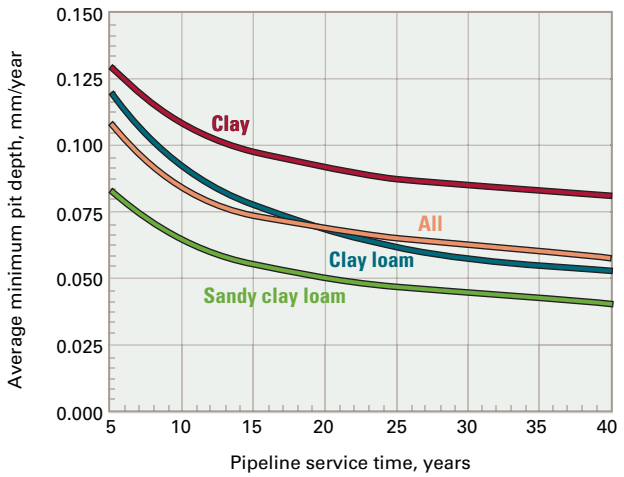
PIT DEPTH

Fig. 1



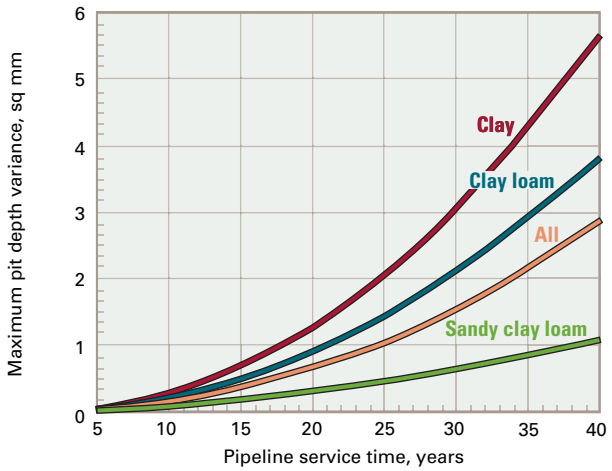
PIT GROWTH RATE

Fig. 2



PIT DEPTH VARIANCE

Fig. 3



needs. Part 1, presented here, describes new deterministic and stochastic predictive models for external pitting corrosion in underground pipelines. The deterministic model considers local chemical and physical properties of soil as well as pipeline coating to predict the time dependence of pitting depth and rate in a range of soils.

Researchers used this model, based on results from a field study, to conduct Monte Carlo simulations establishing the probability distribution of pitting depth and growth rate in the studied soils and their evolution over the pipeline lifetime.

In the last stage of the study, researchers developed an empirical Markov chain-based stochastic model for predicting the evolution of pitting corrosion depth and rate distributions from the observed properties of the soil. Part 2 (next week) will illustrate these models using real-life case studies involving the Monte Carlo simulated and experimental pit depth distributions.

Field study

The values of the soil and pipeline variables listed in Table 1 show a 3-year period at 259 excavation sites at underground pipelines operating in southern Mexico for up to 50 years.[12] External corrosion-caused metal losses with a diameter equal to or less than two times WT qualified as pits. In each exposed pipeline segment in situ measurements (redox potential, pH, pipe-to-soil potential, and soil resistivity) determined maximum pit depth and the value of selected local soil properties.

Soil samples taken from the excavation site determined the rest of the properties considered in the model (soil texture, water content, bulk density, and dissolved chloride, bicarbonate, and sulfate ion concentrations) in a laboratory setting. Pipeline age and coating type also made up part of the collected data sets. Experimental details regarding this field study are published elsewhere.[12]

MODEL VARIABLES

Table 1

Observed variable	Symbol	Unit
Maximum pit depth	d_{max}	mm
Pipeline service time	t	Years
Soil resistivity	re	Ω–m
Sulfate content	sc	ppm
Bicarbonate content	bc	ppm
Chloride content	cc	ppm
Water content	wc	%
pH value	ph	—
Pipe-to-soil potential[1]	pp	v
Soil bulk density	bd	g/ml
Redox potential[2]	rp	mv
Coating type	ct	—

[1]Relative to a $Cu/CuSO_4$(sat.) reference electrode.
[2]Relative to standard hydrogen electrode.

Data analysis

The weight ratio of the three soil separates (sand, silt, and clay) determined soil texture.[13] Textural classes used by the US Department of Agriculture categorized the soil samples. Identified soil categories included:

- Clay (110 samples).
- Sandy clay loam (79 samples).
- Clay loam (61 samples).
- Silty clay loam (6 samples).
- Silty clay (2 samples).
- Silt loam (1 sample).

Only the first three categories contained a large enough number of samples to ensure statistical significance. Standard exploratory statistical tools allowed analysis of the distribution of measured variables, examined the correlation between them, and determined the presence of outliers. Table 2 shows the results of the statistical fitting of measured data for all observed samples (all) and for clay (c), sandy clay loam (scl), and clay loam (cl) samples.

A scoring model previously reported by the authors accounted for the influence of pipe coating type on pit growth.[12] Practical criteria quantifying the general body of practical experience reported in the literature on the susceptibility of pipeline coatings to failure provide the basis for this model (Table 3).[9 13 14] Table 3 also gives the probability of occurrence of each score used in the Monte Carlo simulations.

Depth model

Maximum pit depth was modeled using Equation 1 as a power function of the pipeline service time (t).[12]

Researchers performed a multivariate regression analysis with dmax as the dependent variable and exposure time and soil and pipe characteristics as the independent (predictor) variables. Equations 2 and 3 provided the best correlation between the proportionality and exponent parameters and the predictor variables.

Table 4 gives the adjusted regression coefficients, k_i and n_i, for each soil category. It also reports the value fitted for the pit initiation time (t_0) in each soil class. The pit depth model described by Equations 1-3 is more sensitive to pH value, pipe-to-soil potential, pipe coating type, bulk density, water content, and the dissolved chloride content, in that order.

A Monte Carlo simulation[12] yielded unbiased estimates of the model parameters (kt and nt) in each soil class for typical conditions. Table 4 also shows the values of k_t and n_t.

Fig. 1 shows the time evolution of the average maximum pit depth under average (typical) conditions in each soil class. Equation 1 together with the information presented in Table 4 allowed creation of these curves. Table 4 and Fig. 1 show the order of corrosivity predicted by the proposed model as clay > clay loam > sandy clay loam. These findings agree with those from previous works on pitting corrosion of low carbon steel in soils.[5 7 8 15]

EQUATIONS

$$d_{max} = k(t - t_0)^n \quad (1)$$

Where pitting initiation time (t_0) is treated as an unknown parameter to be determined as part of the analysis, while the pitting porportionality (k) and the exponent (n) parameters are treated as functions of the predictor variables.

$$k = k_0 + k_{rp}rp + k_{ph}ph + k_{re}re + k_{cc}cc + k_{bc}bc + k_{sc}sc \quad (2)$$

$$n = n_0 + n_{pp}pp + n_{wc}wc + n_{bd}bd + n_{ct}ct \quad (3)$$

$$v_m(t) = k'(t - t_0)^{n'} \quad (4)$$

where $n' = n - 1 < 1.0$ and $k' = nk$.

$$\frac{dp_{i,j}(t)}{dt} = \begin{cases} \lambda_{j-1}(t)\,p_{i,j-1}(t) - \lambda_j(t)\,p_{i,i}(t), & j \geq i+1 \\ -\lambda_i(t)\,p_{i,j}(t) \end{cases} \quad (5)$$

$$p_{m,\ell}(t_i, t) = \binom{\ell - 1}{\ell - m} p_s(t_i, t)^m (1 - p_s(t_i, t))^{\ell - m} \quad (6)$$

$$p_s(t_i, t) = \left(\frac{t_i - t_0}{t - t_0}\right)^n, \; t \geq t_i \geq t_0 \quad (7)$$

$$p_t(t) = \sum_{m=1}^{\ell} p_m(t_i)\, p_{m,\ell}(t_i, t) \quad (8)$$

$$f(v; m, t_i, t) = p_m(t_i)\, p_{m,m+v\Delta t}(t_i, t)\, \Delta t \quad (9)$$

$$f(v; t_i, t) = \sum_{m=1}^{N} f(v; m, t_i, t) \quad (10)$$

Rate model

The time derivative of Equation 1 for the maximum pit depth yielded the functional form of the corrosion pitting rate. Accordingly, Equation 4 models time dependence of the average pit growth rate of deeper pits ($v_m(t)$).

This approach has an advantage in that the value of the proportionality and exponent parameters of Equation 4 can be determined from the adjusted regression coefficients in Table 4. The resulting values for of k' and n' are shown in Table 4. Together with the value of t_0 in this table they allow derivation of an empirical formula for the time evolution of the average pitting rate for the four soil categories.

Fig. 2 shows the evolution of the average pit growth rate with pipeline service time for a 40-year span of each soil class. For long exposure periods (30 years and longer), the corrosion rate in all soil classes attains a slightly decreasing value, which is unique for each soil category, and shows a relative variation of less than 10% over a 10-year period, beginning at 30 years. In pipeline integrity management practice pitting rate values within such limits are considered relatively constant.

FIELD CORROSION DATA STATISTICS

Table 2

Variable[1]	Probability density function, expressed in type (mean, variance) format			
	Clay, 110 samples	Sandy clay loam, 79 samples	Clay loam, 61 samples	All, 250 samples
d_{max}, mm	GEVD (2.25, 3.90)[2]	GEVD (1.25, 0.99)	GEVD (1.88, 2.97)	GEVD (1.84, 2.92)
re, Ω–m	Weibull (62, 4275)	Lognormal (49, 2,363)	Weibull (28, 566)	Lognormal (50, 2,931)
sc, ppm	Gamma (131, 12,566)	Weibull (144, 9,836)	Lognormal (208, 65,549)	Lognormal (154, 25,328)
bc, ppm	Lognormal (19, 639)	Lognormal (14, 36)	Lognormal (23, 548)	Lognormal (19, 436)
cc, ppm	Lognormal (53, 4,709)	Lognormal (22, 559)	Lognormal (45, 2,946)	Lognormal (41, 3,135)
wc, %	Normal (24, 47)	Normal (22, 33)	Weibull (25, 27)	Normal (24, 38)
ph	Gumbel (5.94, 0.97)	Normal 6.23, 0.637)	Gumbel (6.36, 0.77)	Gumbel (6.13, 0.84)
pp, v	Normal (–0.86, 0.04)	Normal (–0.92, 0.023)	Normal (–0.81, 0.04)	Normal (–0.86, 0.04)
bd, g/ml	Normal (1.22, 0.003)	Gumbel (1.39, 0.002)	Gumbel (1.32, 5×10^{-4})	Normal (1.30, 0.007)
rp, mv	Uniform (2.14, 348)[3]	Uniform (20, 339)	Uniform (19, 301)	Uniform (2.14, 348)

[1]See Table 1. [2]GEVD = generalized extreme value distribution. [3]The range of variable is reported instead of the two first moments.

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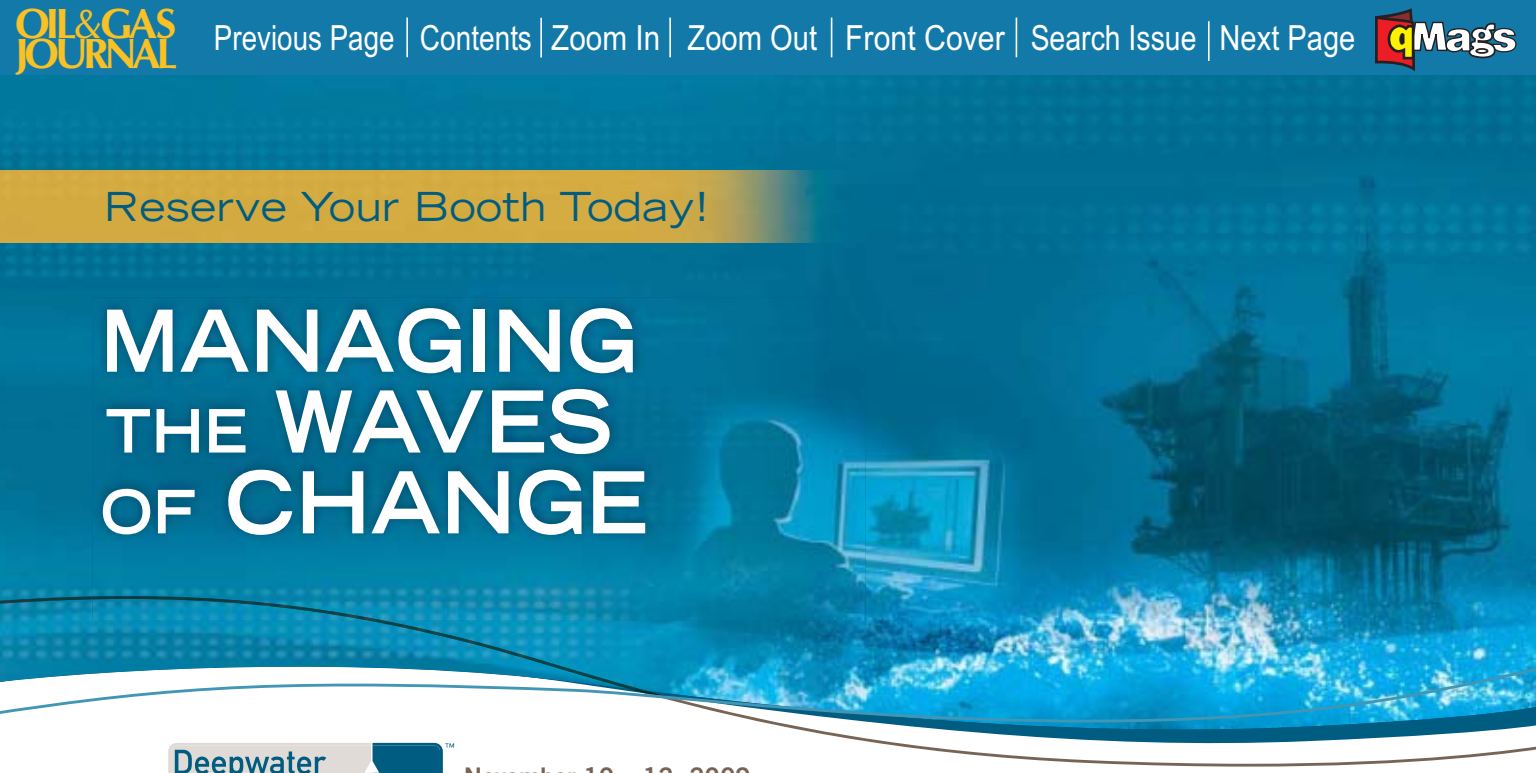

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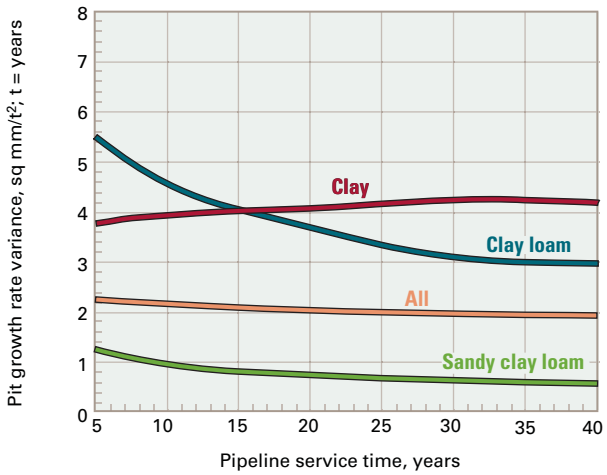
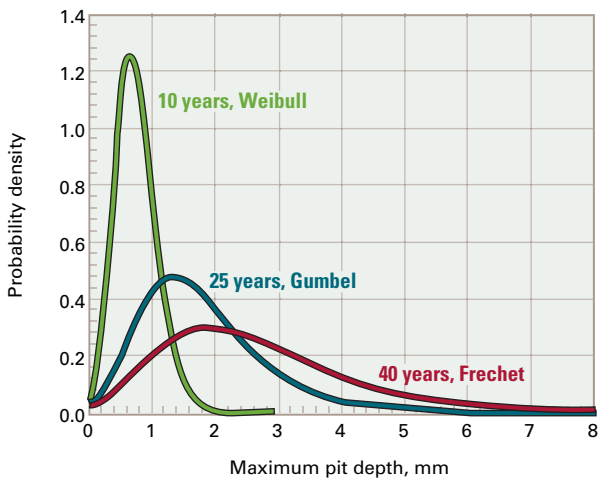
PIT GROWTH RATE VARIANCE

Fig. 4



PIT DEPTH DISTRIBUTIONS

Fig. 5



PIPELINE COATING SCORING MODEL

Table 3

Coating condition	Score	Coating probability by soil: Clay	Sandy clay loam	Clay loam	All
Bare pipe	1.0	0.102	0.194	0.119	0.118
Asphalt enamel	0.9	0.019	0.039	0.017	0.024
Wrap-tape*	0.8	0.421	0.429	0.288	0.382
Coal-tar	0.7	0.449	0.273	0.542	0.443
Fusion-bonded epoxy	0.3	0.009	0.065	0.034	0.033

*Single and double-wrapped polyolefin tape.

Probabilistic distributions

Study of the probability distributions of the maximum pit depth and growth rate used Monte Carlo simulations.[16] Equations 1-4, used together with information from Tables 2-4, simulated these distributions in each soil class for different service times. Researchers drew random values of the predictor variables from the probability distributions fitted to the observed corrosion data (Table 2). Random predictors evaluated pitting depth and rate models 5,000 times.

For each soil class, equally spaced, 2.5-year apart, simulation times simulated Year 5 to Year 40. In most cases, generalized extreme value (GEV) distribution proved the best model for fitting the distributions obtained by means of the Monte Carlo framework.[17] The value of the shape parameter (z) of the fitted GEV distribution determined whether the Weibull ($z < 0$), Gumbel ($z = 0$), or Fréchet ($z > 0$) distribution best fit the simulated data.

Fig. 3 shows the time evolution of nonparametric estimates of the variance of the Monte Carlo-simulated maximum pit depth distribution in each soil class. This figure illustrates the stochastic nature of pitting corrosion in all soil categories. The larger the exposure time is, the higher the uncertainty in the estimates as measured by the variance of the maximum pit depth distribution. Fig. 3 also reveals the variability in the predicted maximum pit depth increasing with soil corrosivity.

Fig. 4 shows the time evolution of the nonparametric estimates of the variance of the Monte Carlo-simulated pitting rate distribution for each soil category. For long-term exposure, the variance of the pitting corrosion rate shows a slightly decreasing trend with time, attaining a relatively constant value differing considerably from one soil to another. Pipeline corrosion literature has already reported this result.[9]

For sufficiently long exposure, the deepest pits are theoretically the most likely to grow, such that the growth rate of the deepest pits largely determines the range of pitting rates. These grow with a steadily decreasing rate because of the stability attained during the long-term diffusion-controlled pit growth. Other factors, such as the buildup of corrosion products, also reduce and stabilize the variability of the pitting corrosion rate as exposure time increases.

Monte Carlo simulations are especially suitable for investigating the shape of the pitting depth and rate probability distributions. The temporal variation of the shape parameter of the GEV distribution fitted to the simulated distributions ascertained which of the three extreme value distributions (Weibull, Gumbel, or Frechet) best fits the maximum pit depth distribution during the lifetime of the pipelines in each soil class.

For relatively short exposure periods, the Weibull distribution is the most appropriate for description of the simulated extreme pit depth data. For long-term exposure, the Gumbel distribution and then the Fréchet distribution become the best fitting distributions. This is the case for all studied soil categories and may explain why different distribution types have been reported for maximum pit depth in previous studies.[7 10 11]

Fig. 5 illustrates how the shape parameter of the fitted GEV distribution varies with exposure times for the all soil class.

The increase in the shape parameter of the GEV distributions fitted to the Monte-Carlo-simulated maximum pit-depth distributions can be associated with the fact that, for sufficiently long exposures, the deeper pits are the most apt to continue growing. This causes the maximum pit depth distribution to skew toward large pit depths and the tail at large depths to become more extensive, as Fig. 5 shows. This behavior also occurs for the micropitting regime of aluminum alloys in tap water[18] and for line pipe steel in laboratory-simulated soil corrosion conditions.[19]

The simulations also revealed the shape parameter of the maximum pit depth distribution as different for different soil categories and that the higher the soil corrosivity and the longer the exposure time, the larger the value of the shape parameter. Other authors previously reported this result in a practical extreme value analysis of steel storage tank pitting.[20] Fig. 6 shows how the type of extreme distribution varies from one soil class to another for a 20-year service lifetime.

The increase in the variance of the distribution of maximum pit depths with exposure time observed in Fig. 3 seems to be related to the sustained growth of the deepest pits. The difference in the growth behavior of the deepest pits with respect to the rest of the pit population increases with the corrosivity of the soil. This explains why the Frechet distribution becomes the best fit for the distribution of maximum pit depths earlier in clay soils than in the rest of the soil categories.

In the case of the corrosion pitting rate (as in the case for the maximum pit depth), the Weibull, Gumbel, and Frechet models become the best fitting distributions as the exposure time increases. The Frechet distribution best fits the pitting rate data for exposures longer than 20 years in all soil environments considered in this study. The previously explained long-term stability of pit growth explains these results. A further detailed discussion of this subject can be found elsewhere.[16]

Fig. 7, for example, shows how the GEV distribution fit to the Monte Carlo-simulated pitting rate distributions evolves with time for the sandy clay loam soil class. After long-term service times, the deepest pits in the pipeline are the most likely to grow, but they do so with a slightly decreasing rate (Fig. 2). The lower rate limit is zero, concentrating the mass of the pitting rate distribution at the lower rate values (left) with increased exposure time.

Concurrently, the higher growth rates of new and short-life shallow pits, though less numerous, contribute to the increased importance of the upper tail of the distribution. Therefore, the variance of the pitting rate distribution becomes more dependent on the less frequent extreme growth rate of the short-life pits. The Fréchet distribution provides the best model to fit the right-skewed, leptokurtic Monte Carlo-simulated distributions of long-term pitting rate data.

Based on these results, the long-term (≥25 years) the Frechet distribution reasonably approximates pit growth rate in the soils considered in this work, with parameters and cumulative probability functions (CDFs) shown in Table 5 and Fig. 8, respectively.

The 80% probability bound (x80) for the pit growth rate obtained by the present study is lower than those published elsewhere.[9 21 22] Taking the all soil class as an example, Table 5 shows the value of x_{80} as 0.087 mm/year (3.5 mils/year). This value is four times less than the NACE recommended 80% upper bound of 0.4 mm/year (~16 mils/year)[21] and three times less than the maximum rate of 0.31 mm/year (~12 mils/year) proposed in ASME B31.8S code.[22]

The differences between the value of x_{80} for the all soil category in Table 5 and the NACE and ASME recommended bounds for pit growth rate are easily explainable. The results of up-to-17-year

Pit growth model coefficients, parameters

Table 4

Variable, parameter	Value by soil class: Clay	Sandy clay loam	Clay loam	All
Soil resistivity, re; Ω–m	-2.2×10^{-4}	-2.1×10^{-4}	-3.0×10^{-4}	-2.6×10^{-4}
Sulphate content, sc; ppm	-5.3×10^{-5}	-1.1×10^{-4}	-2.1×10^{-4}	-1.2×10^{-4}
Bicarbonate content, bc; ppm	-1.3×10^{-3}	-6.8×10^{-4}	-4.9×10^{-4}	-6.4×10^{-4}
Chloride content, cc; ppm	8.4×10^{-4}	8.6×10^{-4}	1.8×10^{-3}	8.7×10^{-4}
Water content, wc; %	3.7×10^{-3}	4.5×10^{-4}	1.7×10^{-2}	4.6×10^{-4}
pH value, ph	-5.9×10^{-2}	-6.4×10^{-2}	-1.2×10^{-1}	-6.5×10^{-2}
Pipe/soil potential, pp; v	4.9×10^{-1}	5.1×10^{-1}	4.6×10^{-1}	5.2×10^{-1}
Bulk density, bd; g/ml	-1.0×10^{-1}	-1.6×10^{-1}	-9.9×10^{-2}	-9.9×10^{-2}
Redox potential, rp; mv	-9.0×10^{-5}	-1.8×10^{-4}	-1.1×10^{-4}	-1.8×10^{-4}
Coating type, ct	4.7×10^{-1}	4.3×10^{-1}	5.7×10^{-1}	4.3×10^{-1}
Pitting initiation time, t_0, years	3.0	2.6	3.1	2.9
Constant propagation term, k_0 (mm/year^{n_0})	5.5×10^{-1}	6.0×10^{-1}	9.8×10^{-1}	6.1×10^{-1}
Constant exponent term, n_0	8.8×10^{-1}	9.6×10^{-1}	2.8×10^{-1}	8.9×10^{-1}
Pit depth propagation factor, k_t (mm/year^{n_t})	0.178	0.144	0.163	0.164
Pit depth exponent factor, n_t	0.829	0.734	0.793	0.780
Pitting rate propagation factor, k'_t (mm/year^{n_t})	0.148	0.106	0.129	0.128
Pitting rate exponent factor, n'_t	–0.171	–0.266	–0.207	–0.220

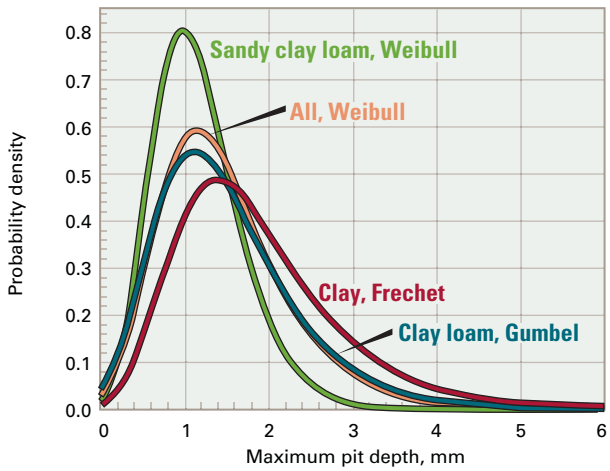
Long-term pit growth rate distribution

Table 5

Soil	Frechet cumulative probably function: $F(x) = \exp\{-((x-\lambda)/\eta)^{-\xi}\}$, $x \geq \lambda$, $\xi > 0$, and $\eta > 0$: ξ	η, mm/year	λ, mm/year	Mean, mm/year	Variance, sq mm/t²; t = year	x_{80}, mm/year
Clay	6.03	0.227	–0.172	0.084	0.0040	0.119
Clay loam	4.04	0.112	–0.079	0.057	0.0032	0.083
Sandy clay loam	24.1	0.453	–0.42	0.044	0.0007	0.062
All	8.01	0.231	–0.191	0.062	0.0020	0.087

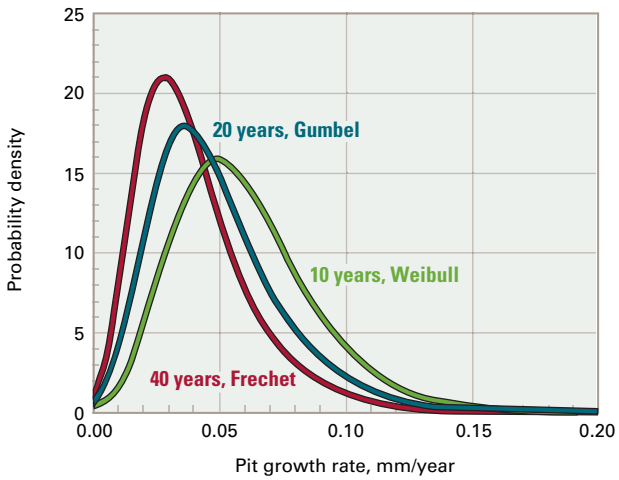
20-YEAR PIT DEPTH DISTRIBUTION

Fig. 6



SANDY CLAY LOAM PITTING RATE DISTRIBUTION

Fig. 7

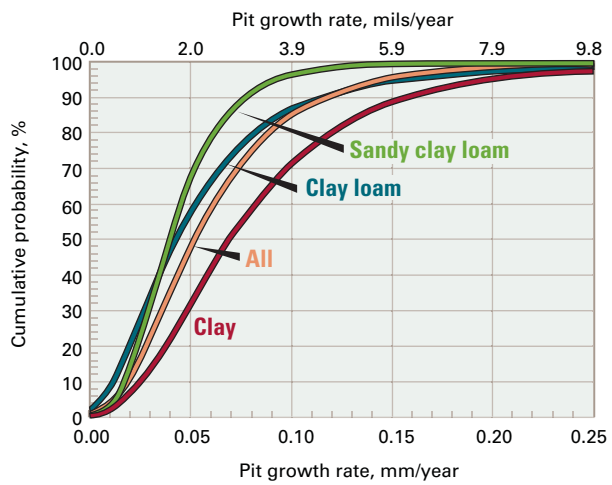


corrosion tests of cathodically unprotected, bare steel coupons in a range of soils provide the basis for the NACE and ASME recommendations.[21] These conditions contrast with those of the pipelines considered in this study, which are under the influence of more realistic operating conditions with moderated potential for corrosivity.

Table 2 presents information corroborating studied pipelines as having been exposed to weakly-acidic soil environments with a relatively high resistivity (~5,000 W–cm), a redox potential above 100 mv, and a pipe-to-soil potential (natural or imposed) close to the optimum level of cathodic protection.

LONG-TERM CUMULATIVE PROBABILITY FUNCTION

Fig. 8



Markov chain model

A continuous-time, non-homogenous linear growth (pure birth) Markov process[23] modeled pipeline corrosion pitting.[24] This model assumes the pipe wall is divided into N discrete states and pit depth at any point in time t can be represented by a discrete random variable D with probability $P\{D(t) = i\} = p_i(t)$, $i = 1, 2....N$. It also assumes the probability that if damage at the i-th state jumps one state during a short interval of time Δt can be written as $\lambda_i(t)\Delta t + o(\delta t)$.

For a linear growth Markov process with intensities $\lambda_i(t) = i\lambda(t)$, Equation 5 governs the probability pitting damage presently in state i will be in state j ($j \geq i$) at some later time.[23]

The solution to this equation provides the conditional probability of transition of the pitting damage from the m-th to the ℓ-th state ($\ell \geq m$) in the time interval (t_i,t); that is, $p_{m,\ell}(t_i,t) = P\{D(t) = \ell \mid D(t_i) = m\}$. Equation 6 depicts this probability in closed form.[23]

Equation 6 describes the probability of increasing pit depth from m to ℓ in an interval of length $t - t_i$ as following a negative binomial distribution NegBin(r,p) with parameters r = m and p = p_s. The authors recently have shown that when the power function given by Equation 1 accurately describes the time evolution of maximum pit depth, the probability ps in Equation 6 can be obtained using Equation 7.[24]

Knowing the pitting corrosion initiation time (t_0) and the pitting exponent factor (n) allows prediction of the evolution of corrosion pitting damage in a given pipeline from the measured (or assumed) initial pit depth distribution ($p_m(t_i)$) and the observed local soil and pipe characteristics.

For example the results of in-line inspection of the pipeline can predict $p_m(t_i)$ with t_i as the time of the inspection. In addition, soil and pipe properties can estimate t_0 and n, using Equation 3 together with information shown in Tables 2 and 4. Equation 6 together with Equation 8 can determine the probability of pitting damage depth at any future time, $p_l(t)$, once $p_m(t_i)$ has been obtained and p_s has been deter-

mined from t_0 and n.[24]

Furthermore, $p_{m,1}(t_i,t)$, allows an estimate of the probability distribution of the damage rate f (v; m, t_i, t) associated with the pitting corrosion process over the interval of length $\Delta t = t - t_i$, when the damage depth is at the m-th state in the moment of time t_i. Equation 9 provides this estimation.

Using Equation 10 from f (v; m, t_i, t) provides a straightforward estimation of the probability distribution of the damage rate associated with the entire pipeline pit population.

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Correction

In the articles "US construction plans slide; pipeline companies experience flat 2003, continue mergers," by Warren R. True and Jeannie Stell, and "US gas carriers see 2004 net jump; construction plans rebound," by Christopher E. Smith, Warren R. True, and Jeannie

US PIPELINE COSTS: ESTIMATED VS. ACTUAL, 2003-04

Table 7

Size, in.	Location	Length, miles	$ Materials	Labor	Misc.	ROW & damages	Total	$/mile
Land pipelines								
24	Idaho	4.80						
	Estimated		1,388,000	7,032,000	808,037	2,320,000	11,548,037	2,405,841
	Actual		1,029,000	7,485,000	608,215	2,704,000	11,826,215	2,463,795
24	Idaho	9.40						
	Estimated		2,096,000	10,352,000	1,039,851	1,427,000	14,914,851	1,586,686
	Actual		1,572,000	10,913,000	749,321	1,312,000	14,546,321	1,547,481
24	Idaho	11.20						
	Estimated		1,992,000	5,878,000	662,325	974,000	9,506,325	848,779
	Actual		1,885,000	7,514,000	549,826	711,000	10,659,826	951,770
24	Idaho	19.60						
	Estimated		3,862,000	13,273,000	1,463,739	2,393,000	20,991,739	1,071,007
	Actual		3,253,000	15,318,000	1,089,921	1,509,000	21,169,921	1,080,098
30	Alabama	1.45						
	Estimated		903,828	1,558,837	1,286,099	231,125	3,979,889	2,744,751
	Actual		545,626	1,793,402	646,769	83,964	3,069,761	2,117,077
30	Wyoming	15.50						
	Estimated		4,321,000	6,785,000	960,372	1,713,000	13,779,372	888,992
	Actual		4,480,000	8,169,000	739,589	951,000	14,339,589	925,135
30	Wyoming	30.60						
	Estimated		8,322,000	11,071,000	1,682,306	3,010,000	24,085,306	787,102
	Actual		7,191,000	11,949,000	1,128,847	1,712,000	21,980,847	718,328
30	Louisiana-Arkansas	41.70						
	Estimated		14,226,000	14,480,000	10,308,000	2,062,000	41,076,000	985,036
	Actual		15,650,186	14,665,395	8,418,671	2,533,009	41,267,261	989,623
36	New Jersey (L)	3.59						
	Estimated		1,993,000	4,446,000	2,443,000	412,000	9,294,000	2,588,858
	Actual		1,638,000	3,735,000	1,767,000	264,000	7,404,000	2,062,396
36	New Jersey (L)	3.71						
	Estimated		1,935,000	4,006,000	2,298,000	592,000	8,831,000	2,380,323
	Actual		1,587,000	3,725,000	1,709,000	330,000	7,351,000	1,981,402
36	New Jersey (L)	4.05						
	Estimated		2,767,000	7,339,000	3,038,000	1,047,000	14,191,000	3,503,951
	Actual		2,268,000	5,070,000	2,237,000	410,000	9,985,000	2,465,432
36	New Jersey (L)	4.45						
	Estimated		2,143,000	5,382,000	2,667,000	478,000	10,670,000	2,397,753
	Actual		1,754,000	6,171,000	1,694,000	487,000	10,106,000	2,271,011
36	Washington	27.79						
	Estimated		11,412,000	74,435,000	6,269,000	6,034,000	98,150,000	3,531,846
	Actual		12,885,000	72,110,000	4,886,000	4,769,000	94,650,000	3,405,901
36	Illinois	28.08						
	Estimated		8,961,218	31,877,293	4,646,773	11,421,176	56,906,460	2,026,583
	Actual		9,273,000	32,792,200	6,532,800	7,383,000	55,981,000	1,993,625

Stell, Table 7 (OGJ, Aug. 23, 2004, p. 64 and OGJ, Sept. 12, 2005, p. 64, respectively) contained errors. The tabulation below and the one on the previous page are corrected versions of the affected portions of each table.

US PIPELINE COSTS: ESTIMATED VS. ACTUAL, 2004-05

Table 7

Size, in.	Location	Length, miles	$ Materials	Labor	Misc.	ROW & damages	Total	$/mile
Land pipelines								
20	Kansas-Missouri	15.67						
	Estimated		2,774,063	4,987,312	1,547,385	510,400	9,819,160	626,622
	Actual		2,140,362	8,754,622	3,114,634	736,506	14,746,124	941,042
24	Texas	7.57						
	Estimated		1,656,950	3,400,160	2,979,770	862,120	8,899,000	1,175,561
	Actual		1,478,422	2,195,793	2,337,518	1,383,294	7,395,027	976,886
30	Minnesota (lat.)	5.60						
	Estimated		2,197,965	3,743,645	3,393,754	648,022	9,983,386	1,782,748
	Actual		1,707,889	3,033,279	2,633,832	760,000	8,135,000	1,452,679
30	Texas	9.28						
	Estimated		2,892,740	3,768,080	4,808,060	1,614,120	13,083,000	1,409,806
	Actual		3,478,943	3,405,196	3,184,161	1,761,870	11,830,170	1,274,803
30	Wisconsis (L)	11.70						
	Estimated		4,894,734	12,300,376	4,071,011	1,777,233	23,043,354	1,969,517
	Actual		4,755,597	11,894,215	4,528,260	2,653,663	23,831,735	2,036,900
36	Pennsylvania	1.79						
	Estimated		1,946,376	3,385,472	1,271,642	103,082	6,706,572	3,746,688
	Actual		1,279,273	2,803,661	1,732,420	107,649	5,923,003	3,308,940
36	Pennsylvania	4.64						
	Estimated		3,139,584	6,079,690	2,646,766	185,037	12,051,077	2,597,215
	Actual		2,654,954	8,976,070	3,475,723	103,325	15,210,072	3,278,033
36	Pennsylvania	4.90						
	Estimated		3,499,499	5,882,401	2,539,057	195,405	12,116,362	2,472,727
	Actual		1,978,497	4,762,775	2,553,970	48,661	9,343,903	1,906,919
36	New Jersey	6.30						
	Estimated		3,608,635	14,425,530	5,021,594	486,173	23,541,932	3,736,815
	Actual		3,435,120	14,325,517	8,413,569	409,838	26,584,044	4,219,690
36	New Jersey	7.10						
	Estimated		3,297,041	11,648,624	5,383,912	2,001,236	22,330,813	3,145,185
	Actual		2,268,000	5,070,000	2,237,000	410,000	9,985,000	1,406,338
36	Pennsylvania	12.46						
	Estimated		7,438,033	15,769,692	7,143,706	480,084	30,831,515	2,474,439
	Actual		5,383,330	15,022,698	9,266,102	341,432	30,013,562	2,408,793

Equipment/Software/Literature

Two transmitters added to wireless family

Two discrete-input transmitters have been added to the family of XYR wireless devices: The STXW 500 and the STTW 401 transmitters can convert any measurement device with a contact-closure switch input into a wireless input, enabling manufacturers to decrease costs and improve efficiency by wirelessly monitoring more processes at their plants.

The transmitters are suited for applications such as wirelessly monitoring level switches, pump status, and system alarms.

The new devices can transmit signals from as many as three contact switches. The STXW 500 transmitter accepts three discrete-digital inputs while the STTW 401 transmitter accepts a thermocouple input and two discrete-digital inputs. Both transmitters carry intrinsically safe approvals for use in hazardous areas from FM Global and the Canadian Standards Association.

These new XYR 6000 transmitters enable plants to convert existing measurement devices to wireless solutions without needing to replace the equipment.

The STXW 500 and STTW 401 transmitters complement the other wireless transmitters in the firm's XYR 6000 product line, which includes: absolute and differential pressure transmitters, temperature transmitters, analog transmitters, corrosion monitoring transmitters, and gauge pressure transmitters.

Source: **Honeywell International Inc.,** 101 Columbia Rd., Morristown, NJ 07962.

New on line control valve sizing program

FlexSelect is a new control valve size selection process for this firm's rotary control FlexStream technology.

This on line program (http://www.mogas.com/Valvesizing/login.aspx) can help users determine the appropriate valve and trim configuration for their quarter-turn control valve needs.

After inputting the appropriate data into the program, an estimated sizing configuration will be generated that, if given the proper data, will show the client the recommended characteristics to meet the requirements for their application.

The program is for the use of control valve applications using proprietary FlexStream technology.

Control valves utilizing FlexStream force fluids or gases through a series of right angle turns, providing the ability to control each stage of pressure letdown, while removing kinetic energy from fluids and lowering pressure in a controlled manner.

The trim element delivers pressure reduction, velocity control, and noise reduction. Additionally, the tortuous paths in the trim help to combat cavitation and flashing.

Source: **MOGAS Industries Inc.,** 14330 E. Hardy St., Houston, TX 77039.

Services/Suppliers

Noble Denton,

London, has appointed Ian Bonnon group managing director, renewables. He will develop the renewables business globally, and the new position reflects Noble Denton's intention to secure significant worldwide market share in the provision of engineering, consultancy, and project management services to the renewables industry. Over the last 10 years, Bonnon has led the development of the UK renewables business within Noble Denton. He has more than 28 years of experience in the oil and gas, renewable energy, marine, and subsea cable industries. He joined BOMEL in 1998 as engineering manager and in 2003 was appointed to the position of director of engineering and projects. In 2004, following the acquisition of BOMEL by Noble Denton, he was appointed managing director of BOMEL. In 2008, Bonnon was named Europe southern operations director in Noble Denton.


Bonnon

Noble Denton, wholly owned by Germanischer Lloyd, is a provider of life cycle marine and offshore engineering services to the oil and gas, marine, and renewables industries.

National Oilwell Varco,

Houston, has named Hege Kverneland senior vice-president and chief technology officer, replacing Bob Bloom, who is retiring after 40 years of service to NOV. She is relocating from Stavanger to Houston. Kverneland has an MS in mechanical engineering from the Norwegian University of Science and is a recent graduate of Harvard Business School's General Management Program. She has 10 years of extensive engineering and product management background, contributing to quality assurance and research and product development. Kverneland began with Hitec in 1994, joining NOV through acquisition. She has authored numerous peer-reviewed technical papers, as well as two textbooks on offshore hydraulics.

NOV is a leader in the design, manufacture, and sale of comprehensive oil field systems and components, tubular inspection and coatings, integrated systems, drill string products, lifting and handling equipment, as well as in providing supply chain integration services to the upstream oil and gas industry.

Cameron,

Houston, has acquired the MaxTorque line of products and services. The business will now be offered through Cameron's Flow Control division, part of the company's Drilling & Production Systems group. MaxTorque designs, manufactures, markets, and sells high-performance quarter-turn and multi-turn gear operators for motorized and manual applications, subsea operators, Navy-specific operators, overrides, and engineered solutions. The company has a manufacturing plant in Limerick, Me., that will continue to develop, sell, and service these products.

Cameron is a leading provider of flow equipment products, systems, and services to the worldwide oil, gas, and process industries.

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CRDASSAY Current

Worldwide Oil Field Production Survey — Field name, field type, discovery date, and depth.
E1077 Current E1077C Historical, 1980 to current

Enhanced Oil Recovery Survey — Covers active, planned and terminated projects worldwide. Updated biennially in March.
E1048 Current E1148C Historical, 1986 to current

Worldwide Gas Processing Survey — Gas processing plants worldwide with details.
E1209 Current E1219C Historical, 1985 to current

International Ethylene Survey — Information on country, company, location, capacity, etc.
E1309 Current E1309C Historical, 1994 to current

LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current	Historical 1996–Current
Refinery	E1340	E1340C
Pipeline	E1342	E1342C
Petrochemical	E1341	E1341C
Gas Processing	E1344	E1344C

U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
PIPEMILL

OGJ 200/100 International Company Survey — Lists valuable financial and operating data for the largest 200 publicly traded oil and gas companies.
E1345 Current E1145C Historical 1989 to current

Oil Sands Projects — Planned Canadian projects in four Excel worksheets. Includes mining, upgrading, in situ projects, and historical table with wells drilled back to 1985.
OILSANDPRJ

Production Projects Worldwide — List of planned production mega-projects.
PRODPROJ

See website for prices

www.ogjresearch.com

Imports of crude and products

	Districts 1–4		District 5		Total US		
	7-3 2009	6-26 2009	7-3 2009	6-26 2009	7-3 2009	6-26 2009	*7-4 2008
	1,000 b/d						
Total motor gasoline	1,176	917	31	62	1,207	979	1,163
Mo. gas. blending comp.	913	668	31	62	944	730	627
Distillate	221	165	0	0	221	165	142
Residual	376	305	49	0	425	305	257
Jet fuel–kerosine	36	25	63	36	99	61	34
Propane–propylene	85	89	4	1	89	90	74
Other	(147)	196	30	(6)	(117)	190	694
Total products	**2,660**	**2,365**	**208**	**155**	**2,868**	**2,520**	**2,991**
Total crude	**8,134**	**8,191**	**1,090**	**1,172**	**9,224**	**9,363**	**9,547**
Total imports	**10,794**	**10,556**	**1,298**	**1,327**	**12,092**	**11,883**	**12,538**

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

Purvin & Gertz LNG netbacks—July 10, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.74	4.09	5.28	3.99	4.63	5.21
Everett	2.77	0.89	2.45	0.99	1.37	3.03
Isle of Grain	2.74	0.87	2.19	0.79	1.34	2.21
Lake Charles	0.94	–0.65	0.74	–0.52	–0.37	1.47
Sodegaura	3.83	5.58	4.08	5.61	4.95	3.25
Zeebrugge	4.55	2.65	3.94	2.56	3.08	3.99

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,351	55,142	37,269	11,338	67,458	15,036	3,765
PADD 2	82,394	50,804	24,445	7,807	31,612	1,165	23,734
PADD 3	181,042	71,095	39,299	14,122	44,296	15,557	33,279
PADD 4	16,755	6,188	1,950	640	3,301	345	[1]1,383
PADD 5	52,755	29,911	23,737	8,932	12,071	4,479	—
July 3, 2009	**347,297**	**213,140**	**126,700**	**42,839**	**158,738**	**36,582**	**62,161**
June 26, 2009	**350,193**	**211,238**	**125,766**	**41,872**	**154,999**	**37,265**	**60,752**
July 4, 2008[2]	**293,936**	**211,766**	**105,084**	**38,764**	**122,501**	**39,366**	**44,001**

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

Refinery report—July 3, 2009

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,404	1,374	2,321	88	388	105	54
PADD 2	3,315	3,297	2,207	202	861	42	281
PADD 3	7,269	7,159	3,022	623	2,047	294	732
PADD 4	556	555	313	27	179	10	[1]75
PADD 5	2,796	2,581	1,391	444	555	133	—
July 3, 2009	**15,340**	**14,966**	**9,254**	**1,384**	**4,030**	**584**	**1,142**
June 26, 2009	**15,373**	**14,992**	**9,241**	**1,321**	**4,184**	**559**	**1,050**
July 4, 2008[2]	**15,686**	**15,488**	**8,929**	**1,526**	**4,641**	**635**	**1,160**
	17,672 Operable capacity		**86.8 utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*7-10-09	*7-11-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	66.99	148.95	–81.95	–55.0
Brent crude	61.01	138.95	–77.94	–56.1
Crack spread	5.99	10.00	–4.01	–40.1
FUTURES MARKET PRICES				
One month				
Product value	68.76	153.57	–84.81	–55.2
Light sweet crude	61.48	140.04	–78.56	–56.1
Crack spread	7.28	13.54	–6.26	–46.2
Six month				
Product value	70.45	155.39	–84.94	–54.7
Light sweet crude	65.94	142.03	–76.09	–53.6
Crack spread	4.51	13.37	–8.86	–66.3

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

OGJ GASOLINE PRICES

	Price ex tax 7-8-09	Pump price* 7-8-09	Pump price 7-9-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	208.5	255.0	412.7
Baltimore	211.5	253.4	403.5
Boston	216.1	258.0	406.5
Buffalo	207.5	268.4	421.5
Miami	221.8	273.4	423.5
Newark	211.8	244.4	395.9
New York	202.5	263.4	413.9
Norfolk	210.8	249.2	395.5
Philadelphia	213.7	264.4	412.6
Pittsburgh	212.6	263.3	403.0
Wash., DC	226.3	264.7	412.7
PAD I avg	213.0	259.8	409.2
Chicago	233.8	298.2	444.7
Cleveland	219.8	266.2	401.4
Des Moines	216.9	257.3	399.7
Detroit	222.8	282.2	410.7
Indianapolis	209.8	269.2	400.7
Kansas City	202.4	238.4	396.7
Louisville	223.3	264.2	403.8
Memphis	202.3	242.1	390.5
Milwaukee	223.9	275.2	412.8
Minn.-St. Paul	216.3	260.3	401.7
Oklahoma City	197.3	232.7	388.0
Omaha	193.5	238.8	398.9
St. Louis	200.4	236.4	393.8
Tulsa	193.2	228.6	387.4
Wichita	198.0	241.4	376.8
PAD II avg	210.3	255.4	400.5
Albuquerque	218.3	254.7	389.7
Birmingham	210.4	249.7	397.7
Dallas-Fort Worth	215.3	253.7	402.7
Houston	211.3	249.7	394.7
Little Rock	207.5	247.7	396.6
New Orleans	211.3	249.7	399.7
San Antonio	205.3	243.7	392.7
PAD III avg	211.4	249.9	396.3
Cheyenne	222.5	254.9	394.8
Denver	221.6	262.0	410.4
Salt Lake City	215.1	258.0	402.9
PAD IV avg	219.8	258.3	402.7
Los Angeles	225.9	293.0	458.7
Phoenix	217.0	254.4	425.7
Portland	231.7	275.1	433.7
San Diego	228.3	295.4	467.7
San Francisco	236.3	303.4	462.7
Seattle	233.5	289.4	442.7
PAD V avg	228.8	285.1	448.5
Week's avg.	**214.5**	**260.1**	**409.1**
June avg.	**214.6**	**260.2**	**404.2**
May avg.	**179.0**	**224.6**	**372.9**
2009 to date	**166.0**	**211.6**	—
2008 to date	**300.6**	**344.3**	—

*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

	7-3-09 ¢/gal		7-3-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	176.00	New York Harbor	163.67
Gulf Coast	171.00	Gulf Coast	162.67
Los Angeles	176.63	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	170.67	ARA	170.57
Singapore	178.33	Singapore	174.17
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	179.13	New York Harbor	144.95
Gulf Coast	178.25	Gulf Coast	146.14
Los Angeles	187.63	Los Angeles	171.49
		ARA	143.61
		Singapore	150.44

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

BAKER HUGHES RIG COUNT

	7-10-09	7-11-08
Alabama	4	5
Alaska	5	6
Arkansas	45	60
California	20	42
Land	20	42
Offshore	0	0
Colorado	45	109
Florida	1	2
Illinois	1	1
Indiana	4	2
Kansas	19	11
Kentucky	9	12
Louisiana	130	182
N. Land	78	76
S. Inland waters	8	22
S. Land	11	27
Offshore	33	57
Maryland	0	1
Michigan	0	1
Mississippi	9	11
Montana	0	12
Nebraska	0	0
New Mexico	38	84
New York	2	5
North Dakota	40	69
Ohio	8	13
Oklahoma	82	200
Pennsylvania	43	24
South Dakota	1	2
Texas	336	908
Offshore	2	7
Inland waters	0	1
Dist. 1	12	21
Dist. 2	16	30
Dist. 3	26	61
Dist. 4	31	95
Dist. 5	77	183
Dist. 6	42	120
Dist. 7B	14	31
Dist. 7C	15	70
Dist. 8	52	139
Dist. 8A	8	25
Dist. 9	19	43
Dist. 10	22	82
Utah	16	44
West Virginia	20	26
Wyoming	30	76
Others—HI-1; NV-2; VA-5;	8	14
Total US	**916**	**1,922**
Total Canada	**178**	**414**
Grand total	**1,094**	**2,336**
US Oil rigs	234	370
US Gas rigs	672	1,544
Total US offshore	37	67
Total US cum. avg. YTD	**1,124**	**1,824**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	7-10-09 Percent footage*	Rig count	7-11-08 Percent footage*
0-2,500	34	2.9	80	3.7
2,501-5,000	60	68.3	138	48.5
5,001-7,500	113	21.2	258	14.7
7,501-10,000	189	3.1	476	3.5
10,001-12,500	183	8.7	488	2.6
12,501-15,000	136	—	324	—
15,001-17,500	120	—	146	—
17,501-20,000	50	—	86	—
20,001-over	30	—	38	—
Total	**915**	**9.6**	**2,034**	**6.7**
INLAND	13		31	
LAND	864		1,940	
OFFSHORE	38		63	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]7-10-09	[2]7-11-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	651	648
California	638	647
Colorado	61	66
Florida	6	6
Illinois	29	27
Kansas	99	105
Louisiana	1,409	1,314
Michigan	15	16
Mississippi	61	60
Montana	92	85
New Mexico	161	163
North Dakota	188	165
Oklahoma	169	176
Texas	1,310	1,339
Utah	55	60
Wyoming	149	144
All others	65	75
Total	**5,177**	**5,117**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	7-3-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	60.00
California-Kern River 13°	51.35
Lost Hills 30°	59.65
Wyoming Sweet	49.39
East Texas Sweet	55.75
West Texas Sour 34°	50.25
West Texas Intermediate	56.25
Oklahoma Sweet	56.25
Texas Upper Gulf Coast	49.25
Michigan Sour	48.25
Kansas Common	55.50
North Dakota Sweet	46.75

*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]	7-3-09
United Kingdom-Brent 38°	67.96
Russia-Urals 32°	67.83
Saudi Light 34°	67.17
Dubai Fateh 32°	70.42
Algeria Saharan 44°	69.35
Nigeria-Bonny Light 37°	70.59
Indonesia-Minas 34°	73.64
Venezuela-Tia Juana Light 31°	68.92
Mexico-Isthmus 33°	68.81
OPEC basket	69.29
Total OPEC[2]	68.84
Total non-OPEC[2]	68.00
Total world[2]	68.47
US imports[3]	66.87

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

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

US NATURAL GAS STORAGE[1]

	7-3-09	6-26-09	7-3-08	Change, %
	bcf			
Producing region	1,013	1,001	715	**41.7**
Consuming region east	1,349	1,289	1,168	**15.5**
Consuming region west	434	431	312	**39.1**
Total US	**2,796**	**2,721**	**2,195**	**27.4**
	Apr. 09	**Apr. 08**	**Change, %**	
Total US[2]	**1,903**	**1,436**	**32.5**	

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

International rig count

Region	Jun. 09 Land	Jun. 09 Off.	Jun. 09 Total	Jun. 08 Total
WESTERN HEMISPHERE				
Argentina	45	—	45	79
Bolivia	3	—	3	3
Brazil	32	31	63	52
Canada	124	2	125	266
Chile	2	—	2	1
Colombia	28	—	28	43
Ecuador	10	—	10	10
Mexico	96	28	124	112
Peru	4	1	5	7
Trinidad	—	1	1	5
United States	848	47	895	1,902
Venezuela	47	14	61	84
Other	1	—	1	2
Subtotal	**1,239**	**124**	**1,363**	**2,565**
ASIA-PACIFIC				
Australia	7	6	13	28
Brunei	1	4	5	4
China-offshore	—	23	23	21
India	56	27	83	80
Indonesia	48	13	61	68
Japan	6	—	6	6
Malaysia	—	15	15	17
Myanmar	3	1	4	3
New Zealand	3	—	3	5
Papua New Guinea	2	—	2	4
Philippines	3	—	3	3
Taiwan	—	—	—	—
Thailand	4	9	13	14
Vietnam	—	5	5	9
Other	—	—	—	3
Subtotal	**133**	**103**	**236**	**265**
AFRICA				
Algeria	30	—	30	24
Angola	—	3	3	7
Congo	1	1	2	3
Gabon	—	1	1	2
Kenya	—	—	—	—
Libya	14	—	14	15
Nigeria	1	5	6	5
South Africa	—	—	—	—
Tunisia	2	2	4	5
Other	3	1	4	4
Subtotal	**51**	**13**	**64**	**65**
MIDDLE EAST				
Abu Dhabi	8	3	11	11
Dubai	—	1	1	1
Egypt	31	12	43	51
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	1
Kuwait	10	—	10	11
Oman	50	—	50	55
Pakistan	19	—	19	22
Qatar	2	8	10	11
Saudi Arabia	57	10	67	77
Sudan	—	—	—	—
Syria	24	—	24	21
Yemen	9	—	9	15
Other	3	—	3	1
Subtotal	**213**	**34**	**247**	**277**
EUROPE				
Croatia	—	—	—	—
Denmark	—	2	2	3
France	—	—	—	—
Germany	6	—	6	8
Hungary	3	2	5	5
Italy	2	1	3	4
Netherlands	1	2	3	1
Norway	—	17	17	23
Poland	3	—	3	1
Romania	7	—	7	18
Turkey	3	2	5	5
UK	1	17	18	23
Other	7	1	8	6
Subtotal	**33**	**44**	**77**	**97**
Total	**1,669**	**318**	**1,987**	**3,269**

Definitions, see OGJ Sept. 18, 2006, p. 42.
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	—	—
Caribbean	Houston	Resid.	380	93	1.20
Caribbean	Houston	Resid.	500	72	0.93
N. Europe	New York	Dist.	200	161	2.98
N. Europe	Houston	Crude	400	110	2.97
W. Africa	Houston	Crude	910	63	1.94
Persian Gulf	Houston	Crude	1,900	34	1.95
W. Africa	N. Europe	Crude	910	67	1.51
Persian Gulf	N. Europe	Crude	1,900	30	1.25
Persian Gulf	Japan	Crude	1,750	50	1.69

*June 2009 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

Waterborne Energy Inc. US LNG imports

Country	May 2009	Apr. 2009	May 2008	Change from a year ago, %
	MMcf			
Algeria	0	0	0	—
Egypt	17,200	21,880	0	—
Equatorial Guinea	0	0	0	—
Nigeria	0	8,050	0	—
Norway	2,910	5,870	3,030	–4.0
Qatar	0	0	0	—
Trinidad and Tobago	30,990	23,160	28,520	8.7
Total	**51,100**	**58,960**	**31,550**	**62.0**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
Data not available at press time.

Propane prices

	May 2009	Jun. 2009	May 2008	Jun. 2008
	¢/gal			
Mont Belvieu	70.10	84.64	170.01	181.29
Conway	69.04	78.81	169.06	174.59
Northwest Europe	61.78	73.63	177.58	178.32

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
June 2009						
Product revenues	83.22	76.83	83.75	80.95	75.73	72.48
Feedstock costs	–75.09	–71.18	–69.94	–65.73	–70.46	–72.52
Gross margin	8.13	5.65	13.81	15.22	5.27	–0.04
Fixed costs	–2.13	–2.47	–2.40	–2.80	–2.40	–1.87
Variable costs	–1.42	–1.08	–1.29	–2.30	–2.93	–0.91
Cash operating margin	**4.58**	**2.10**	**10.12**	**10.12**	**–0.06**	**–2.82**
May 2009	3.77	3.14	8.86	9.44	1.74	–1.35
YTD avg.	4.07	–0.25	6.60	9.31	2.75	0.27
2008 avg.	9.09	–22.64	11.53	–19.93	6.35	3.07
2007 avg.	12.60	–14.84	18.66	–8.05	5.75	2.25
2006 avg.	12.54	–2.86	14.97	11.32	5.88	0.90

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

May 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	252.20	216.53	249.38	234.10
Taxes	53.53	38.40	55.83	48.43
Wholesale price	192.40	177.23	183.29	184.34
Spot price	184.75	167.80	183.73	173.69
Retail margin	6.41	0.90	10.26	1.33
Wholesale margin	7.65	9.43	–0.44	10.65
Gross marketing margin	**14.06**	**10.33**	**9.82**	**11.98**
Apr. 2009	19.70	27.62	20.67	26.92
YTD avg.	19.41	18.39	11.67	24.68
2008 avg.	33.11	32.15	27.22	41.81
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	19.94	18.03	27.90

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Margins include ethanol blending in all markets.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Jun. 2009			
Product revenues	39.04	65.28	82.90
Feedstock costs	–20.91	–48.37	–97.55
Gross margin	18.13	16.91	–14.65
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–3.04	–3.51	–4.59
Cash operating margin	**9.71**	**7.04**	**–26.43**
May 2009	12.68	7.88	–25.39
YTD avg.	13.75	9.51	–13.89
2008 avg.	21.00	22.89	–5.91
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.54	22.45	1.36

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

June 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	3.59	2.62
Liquids	0.94	2.32
Gas purchase cost	4.00	3.51
Operating costs	0.07	0.15
Cash operating margin	**0.46**	**1.28**
May 2009	0.30	0.85
YTD avg.	0.23	0.83
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	47%	43%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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Signs scrambled on the inevitable start of recovery

The Editor's Perspective

by Bob Tippee, Editor

Global economic recovery has to start sometime. Now seems like as good a time as any.

The signs, however, are scrambled.

On July 2, the US Bureau of Labor Statistics reported disappointing data for June. Nonfarm payroll employment fell by 467,000 jobs, and the unemployment rate loitered at a gruesome 9.5%.

The number of unemployed Americans is now 14.7 million—up 7.2 million since the start of the recession in December 2007.

The International Monetary Fund, however, sees hope, asserting on July 8 that, "The world economy is stabilizing, helped by unprecedented macroeconomic and financial policy support."

A contemporaneous case in point is GM. With the help of a $50 billion commitment from US taxpayers, the once mighty automaker was poised, as the IMF updated its World Economic Outlook, to emerge from bankruptcy. The turnaround came sooner than had been expected.

But the company's sharply diminished corpus now bears marks—some say scars—of that "policy support" IMF mentioned. GM will be 60.8% owned by the US government, 11.7% by the Canadian government, and 17.5% by the United Auto Workers.

According to news reports, it might change the color of its logo from blue to green.

On the broader economy, IMF doesn't gush optimism.

"The recession is not over, and the recovery is likely to be sluggish," it said.

In first-quarter 2009, the global economy contracted by almost as much as in fourth-quarter 2008.

The IMF now expects global economic activity to contract by 1.4% in 2009 and to expand by 2.5% in 2010. The 2010 forecast exceeds the outlook IMF made in April by a not-so-whopping 0.6 percentage point.

"The downward drag exerted by the financial shock, the sharp fall of global trade, and the general increase in uncertainty and collapse of confidence is gradually diminishing," the IMF said. "However, supportive forces are still weak."

Among those are housing markets yet to bottom out, financial markets still impaired, and bank balance sheets that "still need to be cleaned."

To that list might be added questions about GM's ability to sell cars designed by politicians and labor bosses.

(Online July 10, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

CFTC undercuts crude prices

It was more than a resurgence of economic pessimism that slashed the August contract for benchmark US light, sweet crudes by $11.60/bbl through seven of eight trading sessions to a $59.89/bbl close July 10 on the New York market, said Paul Horsnell, a managing director and head of commodities research at Barclays Capital in London. Market fears that a faltering global economy will further reduce demand for oil probably couldn't have taken the price below $65/bbl, especially against a background of tightening crude supplies, determination of members of the Organization of Petroleum Exporting Countries to raise prices to a sustained $75/bbl, and "broadening fears" that inadequate investments today in exploration and development threaten potential mid-term market stability, Horsnell said.

No, what kicked a hole through the previous price bottom and dropped crude another $5 plus change was Commodities Futures Trading Commission (CFTC) Chairman Gary Gensler's announcement that his group will consider imposing position limits on energy commodities for speculators and will review whether swap dealers, index traders, and exchange-traded fund managers should be exempted. "Faced with somewhat imprecise statements suggesting a series of possible regulatory actions, a strong incentive was created for market participants of all types to draw back…particularly from the long side of US markets," Horsnell said.

He warned, "All traders, regardless of whether they might be classified as speculative or not, were likely to view the CFTC chairman's statement as the renewal of a regulatory wildcard. The most likely belief, again by all types of traders, would be that action would likely be more damaging for holders of longs rather than shorts, and hence an immediate reaction was to close out or scale back longs, or even to open shorts, in response to the reappearance of concerns about the potential instability and unpredictability of the US oil regulatory regime."

Horsnell said, "Regulators are rarely short-run market neutral in the implementation of their actions, and when they speak of potential actions well in advance of specifying and implementing any regulatory changes, the scale of their involvement in the market as an indirect but active part of price determination becomes greater."

In London, the InterContinental Exchange's August contract for North Sea Brent closed at $60.52/bbl on July 10, 64¢ more than the price for benchmark US crude on the New York market, which it usually trails. That price difference "is in effect almost a Gensler risk discount" against US crudes, Horsnell claimed, even allowing for continued tightness in Atlantic crude markets and production outages in Nigeria.

'Regulatory McCarthyism'

The primary market risk is politicians attempting a quick and easy fix for complex medium and long-term financial issues. "Quixotically attacking a perceived but unproved speculative problem may play very well to the galleries in the short run, but it risks diverting policy attention from the real issues; it may increase the volatility it is supposedly trying to reduce, and it may result in the consumer paying more in the long run. In particular, a period of regulatory McCarthyism in relation to the operation of oil markets is unlikely, in our view, to be a good substitute for effective domestic and international energy policies," Horsnell said.

Gensler "seems to hint at a potentially prolonged period of regulatory uncertainty, which is rarely a good factor to increase in any market. In particular, those worried by the extent to which investment is falling behind that necessary to balance the market at reasonable prices are likely to be alarmed by the additional volatility and short-term price weakness caused by regulatory uncertainty," Horsnell said.

Like the trickle of water down a hillside, financial markets tend to follow courses of least resistance. If blocked in one market, traders likely will move naturally to more favorable exchanges abroad. Therefore, Horsnell said, "The ultimate price impact of regulatory decisions…is likely to be very limited indeed. However, in the short run, oil prices do now seem to have an additional determining factor, namely market concerns about the risk of clumsy regulation and implementation."

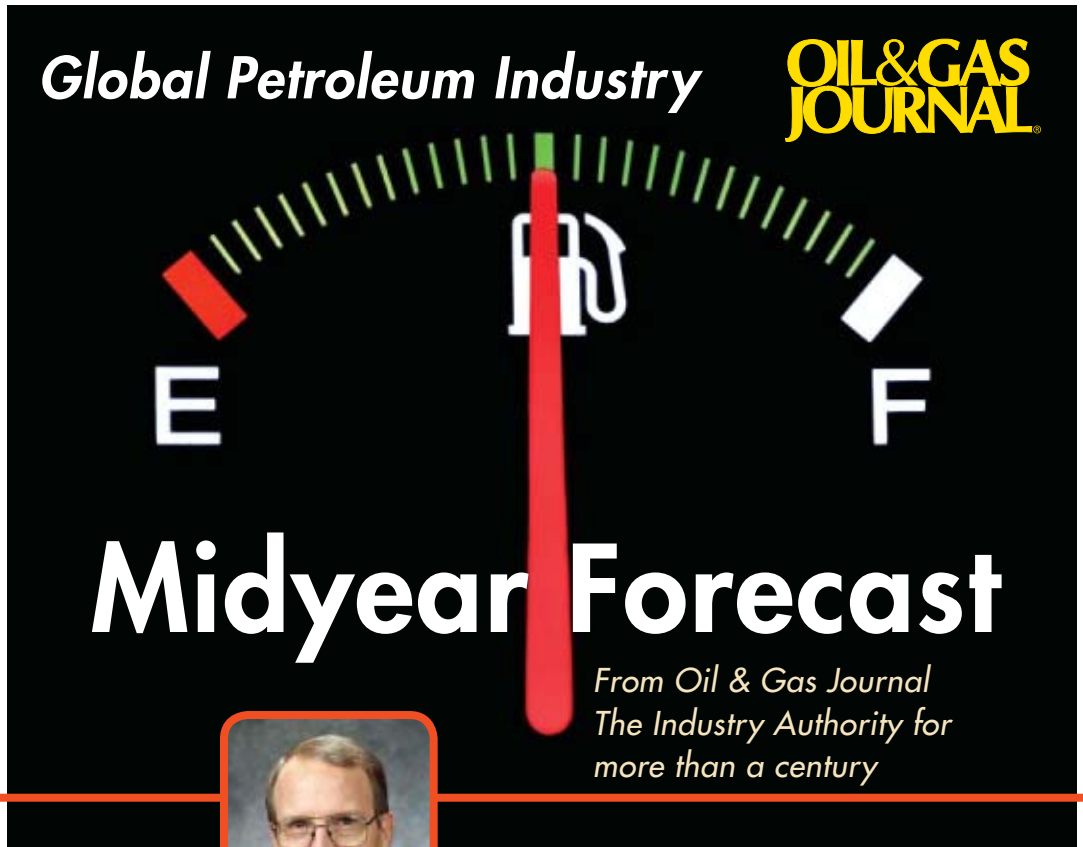
To prevent escapes to other markets, Sens. Maria E. Cantwell (D-Wash.) and Olympia J. Snowe (R-Me.) asked CFTC to revoke exemption of ICE's US crude contracts from direct US oversight.

House Financial Services Committee Chairman Barney Frank (D-Mass.) suggested that any market reform legislation also authorize bilateral sanctions against any country that tries to attract commodity trading business with looser regulations. It is not clear how that would affect private exchanges competing for business in countries that simply maintain their current less-stringent regulations, however.

(Online July 13, 2009; author's e-mail: samf@ogjonline.com)

Half Empty? Half Full?

Our July 22nd webcast is all about perspective.



OGJ Editor, Bob Tippee

July 22, 2009

1:30 pm CST

Register free at:
www.ogjonline.com
(webcast section)

The webcast will discuss highlights of Oil & Gas Journal's annual Midyear Forecast. The Midyear Forecast is a special report that uses first-half data to update projections that appeared in OGJ's Annual Forecast and Review this past January. Both reports project oil and gas markets through the end of the year worldwide, analyze demand product by product in the US, and forecast drilling activity in the US and Canada.

The webcast, to be presented by OGJ Editor Bob Tippee, will summarize the Midyear Forecast projections in key categories, note important changes from January's forecasts, and examine reasons for the adjustments. Marilyn Radler, Senior Editor-Economics, and G. Alan Petzet, Chief Editor-Exploration, will be on hand for questions. Marilyn compiles and writes the Midyear Forecast market projections. Alan assembles the drilling forecast.

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