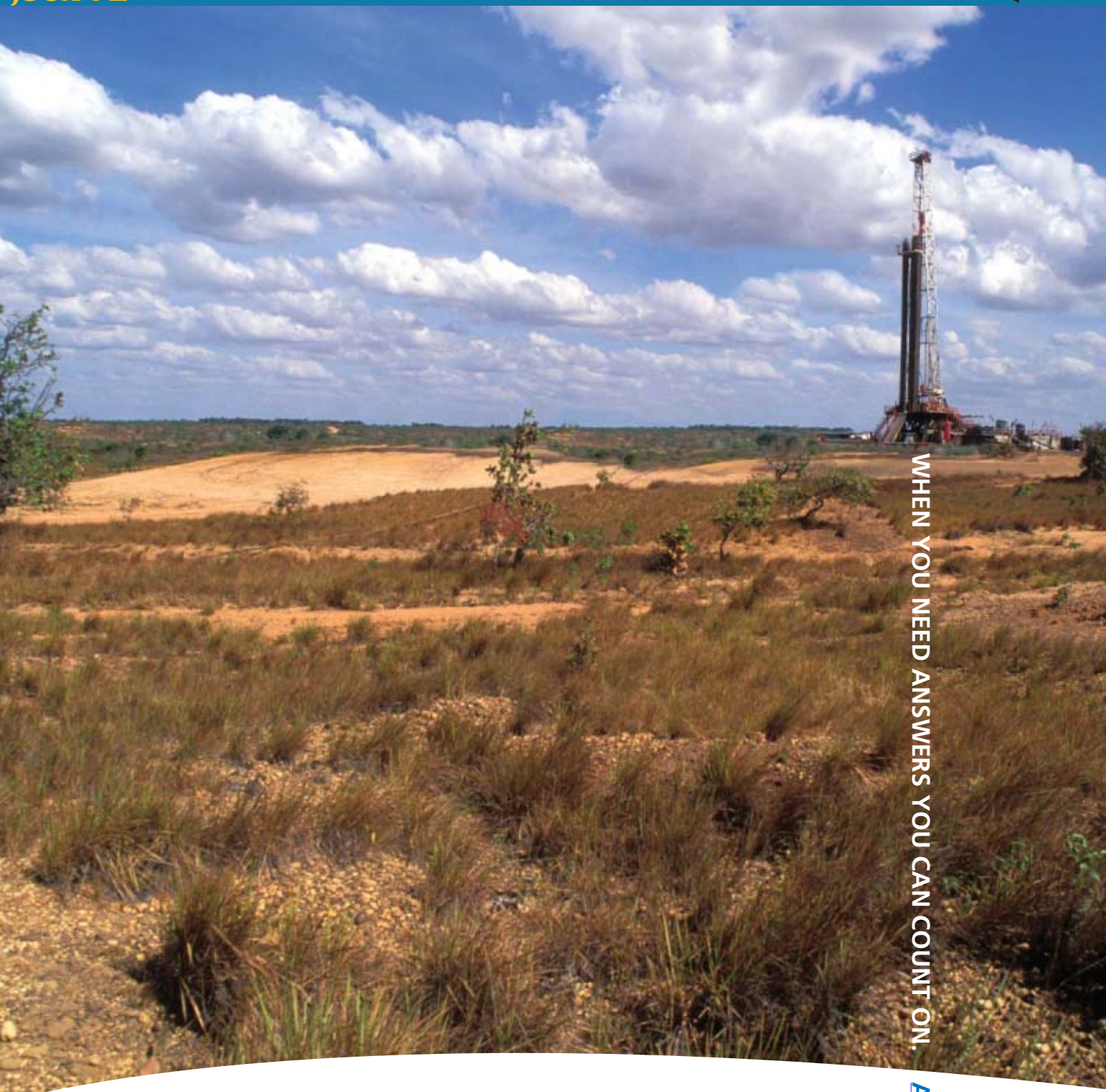

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Forecast and Review

Cairn's Capricorn unit takes position off SW Greenland
Dongguo casing failures derive from many causes
Reactor revamp hikes performance for ULSD production
Supersonic ejector saves fuel gas, reduces CO_2 emissions

OIL&GAS JOURNAL®

Jan. 21, 2008
Volume 106.3

FORECAST AND REVIEW

Energy demand to grow slowly worldwide, stagnate in the US 24
Marilyn Radler, Laura Bell

Smaller drilling gain due in US as Canada's drop persists 35
Alan Petzet

REGULAR FEATURES

Newsletter 5
Letters 12
Calendar 12
Journally Speaking 21
Editorial 23
Equipment/Software/Literature 72
Services/Suppliers 72
Statistics 73
Classifieds 76
Advertisers' Index 79
Editor's Perspective/Market Journal 80

COVER

US demand growth across all energy sources will be small or nil for 2008, according to OGJ's Forecast & Review. This annual special report looks at not only demand for oil and gas, but also nuclear, coal, and renewable energy demand. Weakening in major economies will reverberate, resulting in greater conservation efforts. Worldwide oil demand this year will grow less than 2%.

General Interest

Editorial: Winning back public trust 23

Special Report: Energy demand to grow slowly worldwide, stagnate in the US 24
Marilyn Radler, Laura Bell

Special Report: Smaller drilling gain due in US as Canada's drop persists 35
Alan Petzet

COMMENT: Iraq takes licensing step, but E&P fiscal policy murky 38

Westwood: Big oil needs new business model 39

New UK energy bill calls for simpler regime 40

Argentina cuts local energy supply, bans exports 41

WATCHING THE WORLD: Brazil courts Cuba 41

KazMunayGas increases Kashagan share, influence 42

Trinidad and Tobago bows out of PetroCaribe initiative 43

WATCHING GOVERNMENT: Economic cooling vs. global warming 44

FERC issues final EIS for Broadwater offshore LNG terminal 44

Tanker protection is stretching USCG thin, GAO warns 45

US study commission calls for more alternate fuel R&D 47

Exploration & Development

Cairn's Capricorn unit takes position off SW Greenland 48

Operators chase gas in three Alabama shale formations 49

Drilling & Production

Dongguo casing failures derive from many causes 51
Zhang Ji-Cheng, Song Kao-Ping, Du Ruo-Xia

UNCONVENTIONAL GAS TECHNOLOGY—Conclusion: Life-cycle approach improves coalbed methane production 55
Gary Rodvelt, Matt Blauch, Richard D. Rickman, John A. Ringhisen, Loyd E. East, Glenda Wylie

Processing

Reactor revamp hikes hydrocracker performance for ULSD production 61
Andrew Sharpe, Brent Jones, Gunther Baumgartner, Russell Anderson, Raul Adarme, Marjan Boer

Transportation

GAS TURBINES—Conclusion: Supersonic ejector saves fuel gas, reduces CO_2 emissions 67
Kamal Botros, John Geerligs, Hasan Imran

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The conference board will once again solicit a number of key presentations by industry leaders. As in the past, only by participating in this conference will you be able to receive its benefits, as proceedings will not be published and no Press is ever allowed in the conference area. This is truly a closed forum with open discussion, where the information shared inside the conference room stays inside the conference room. We hope you will join us.

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General Interest — Quick Takes

ConocoPhillips gas pipeline proposal turned down

Alaska Gov. Sarah Palin has notified ConocoPhillips that she rejected the company's proposal to build an Alaska gas pipeline to transport North Slope gas to the Lower 48 states, the governor's office said.

Meanwhile, a 60-day public comment period is under way regarding TransCanada's gas pipeline proposal under the Alaskan Gasline Inducement Act (AGIA). ConocoPhillips's application was outside the AGIA solicitation (OGJ Online, Jan. 7, 2008).

In a Jan. 9 letter to ConocoPhillips's Chief Executive Officer James Mulva, Palin wrote, "Your alternative does not give the state a reason to deviate from the AGIA process."

A ConocoPhillips spokesman in Houston said the company was disappointed, and that the company still believes its pipeline proposal offered "tremendous benefits to the state of Alaska."

Turkey, Syria sign mutual energy, pipeline deal

Turkey and Syria have signed an agreement aimed at enhancing cooperation between their two countries in a number of fields, including a major pipeline development.

After the signing ceremony, Turkish Energy Minister Hilmi Guler said the cooperation agreement included a pipeline that would carry Egyptian natural gas from Aleppo to Turkey's southeastern town of Kilis, and possibly on to European markets if a link-up with the European Union-sponsored Nabucco pipeline scheme comes online.

Cooperation in electric power also would be developed.

Turkey will have the right to take as much as 1.5 billion cu m of gas for its domestic needs from the 62-mile pipeline, and Turkish contractors will participate in the tenders for line construction. Bids are due by Feb. 20.

Prior to the meeting, Guler met with Syrian Minister of Oil Sufiyan al-Aw and said the two countries could jointly explore for oil and gas because they have identical geologies. "Turkey and Syria can work together to find oil and natural gas reserves," Guler said, adding that both countries can "trade electricity and minerals."

StatoilHydro sets higher 2012 production targets

StatoilHydro reported that it hopes to ramp up its total equity production to 2.2 million boe/d by 2012 from 1.96 million boe/d, with the majority of the increase coming from the Norwegian continental shelf.

By 2012, production from the NCS will increase to 1.55 million boe/d from 1.4 million boe/d in 2008. StatoilHydro hopes to keep NCS production at 1.5 million boe/d for the next 10 years.

In contrast, international production will grow to 0.65 million boe/d in 2012 from the current 0.5 million boe/d. However, three quarters of its production-sharing agreements (PSA) are expected to have a major influence on its overall production, as high oil prices would reduce its entitlement and boost taxation in kind. "At an oil price of $75/bbl, PSAs are assumed to have an effect on entitlement production of about 150,000 boe/d in 2008 and 240,000 boe/d in 2012," StatoilHydro said.

Statoil, which merged with Hydro in October 2007, expects annual synergies to be 6 billion kroner before taxes, 2 billion kroner higher than previously estimated. Despite the merger, production in 2007 fell below expectations of 1.7 million b/d because of technical problems with its fields.

The company has budgeted 75 billion kroner in 2008 as capital expenditures and about 80 billion kroner in 2009. "Approximately 50% of the increase from 2007 is related to higher activity levels for sustaining existing production and supporting the group's growth ambition, while the remaining is due to cost inflation, combined with gradually increasing project complexity," StatoilHydro said.

Helge Lund, the company's chief executive, said its focus would be on short-term deliveries and improved operational performance, as it had not met those expectations.

StatoilHydro will drill 70 wells in 2008 under an 18 billion kroner program, and it has secured rigs for all of its wells. These will be split 50-50 between the NCS and internationally.

Most drilling on the NCS will be in mature areas, StatoilHydro said, "but there will also be frontier exploration in the Barents and Norwegian seas." Internationally, the most important wells will be in the US Gulf of Mexico, Brazil, Nigeria, and Azerbaijan. ✦

Exploration & Development — Quick Takes

Equatorial Guinea gets gas-condensate find

A group led by Noble Energy Inc., Houston, will continue exploring and appraising Blocks I and O in the Gulf of Guinea east of Equatorial Guinea's Bioko Island after the latest discovery expanded the company's estimate of the resource.

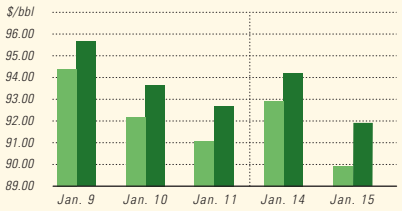
The latest well, I-4, is on Block I in 2,226 ft of water 7 miles southwest of Noble's Belinda discovery on Block O. I-4 flowed 28.9 MMcfd of gas and 1,634 b/d of condensate limited by test equipment capacity from a high-quality Miocene reservoir. It is the last in a six-well program since 2005, only one of which was dry.

The drilling, seismic calibration, and reservoir analysis confirms the area's resource range to be 60% greater than the original predrill estimate, and well results show that liquids make up 40% of the total resource with proper processing, Noble said.

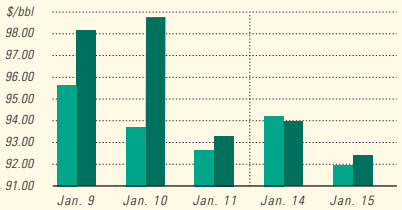
The Sedco 700 drillship is to spud the next well, to verify the

Industry Scoreboard

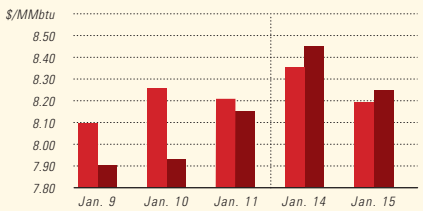
IPE BRENT / NYMEX LIGHT SWEET CRUDE



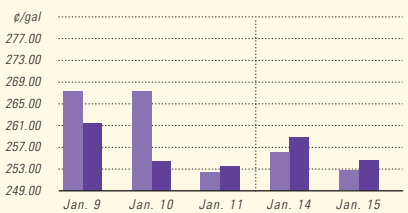
WTI CUSHING / BRENT SPOT



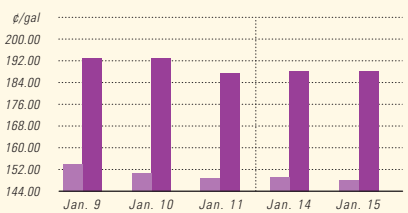
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



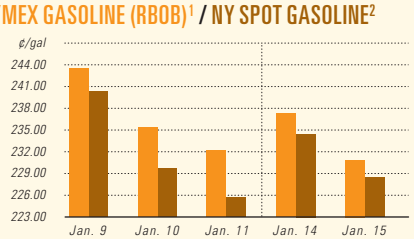
IPE GAS OIL / NYMEX HEATING OIL



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 — 1/21

Latest week 1/4	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	9,331	9,090	2.7	9,304	8,891	4.6
Distillate	4,477	4,268	4.9	4,223	4,267	–1.0
Jet fuel	1,579	1,630	–3.1	1,539	1,616	–4.8
Residual	830	734	13.1	1,005	753	33.5
Other products	5,089	5,048	0.8	5,217	5,032	3.7
TOTAL DEMAND	21,306	20,770	2.6	21,288	20,559	3.5
Supply, 1,000 b/d						
Crude production	5,089	5,169	–1.5	5,051	5,196	–2.8
NGL production[2]	2,390	2,396	–0.3	2,390	2,250	6.2
Crude imports	9,683	9,623	0.6	9,806	10,192	–3.8
Product imports	3,250	3,194	1.8	3,098	3,431	–9.7
Other supply[3]	960	849	13.1	959	1,048	–8.5
TOTAL SUPPLY	21,372	21,231	0.7	21,304	22,117	–3.7
Refining, 1,000 b/d						
Crude runs to stills	15,403	15,095	2.0	15,771	14,964	5.4
Input to crude stills	15,545	15,434	0.7	15,921	15,385	3.5
% utilization	89.2	88.4	—	91.3	88.1	—

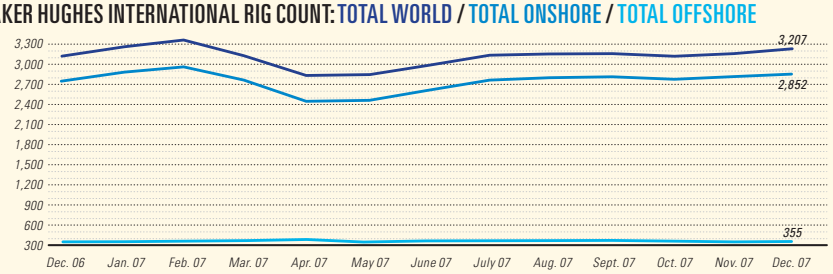
Latest week 1/4	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	282,841	289,577	–6,736	314,686	–31,845	–10.1
Motor gasoline	213,063	207,842	5,221	213,295	–232	–0.1
Distillate	128,693	127,177	1,516	140,965	–12,272	–8.7
Jet fuel-kerosine	39,716	39,026	690	41,462	–1,746	–4.2
Residual	37,374	39,595	–2,221	44,066	–6,692	–15.2
Stock cover (days)[4]			Change, %		Change, %	
Crude	18.4	19.0	–3.2	20.2	–8.9	
Motor gasoline	22.8	22.2	2.7	23.0	–0.9	
Distillate	28.7	28.2	1.8	33.6	–14.6	
Propane	32.5	35.1	–7.4	39.3	–17.3	

Futures prices[5] 1/11			Change		Change	%
Light sweet crude, $/bbl	94.70	98.17	–3.47	56.74	37.96	66.9
Natural gas, $/MMbtu	8.08	7.71	0.37	6.17	1.91	31.0

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

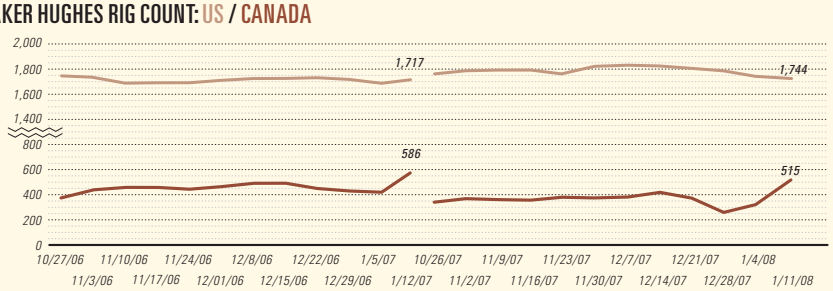
Sources: Energy Information Administration, Wall Street Journal

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

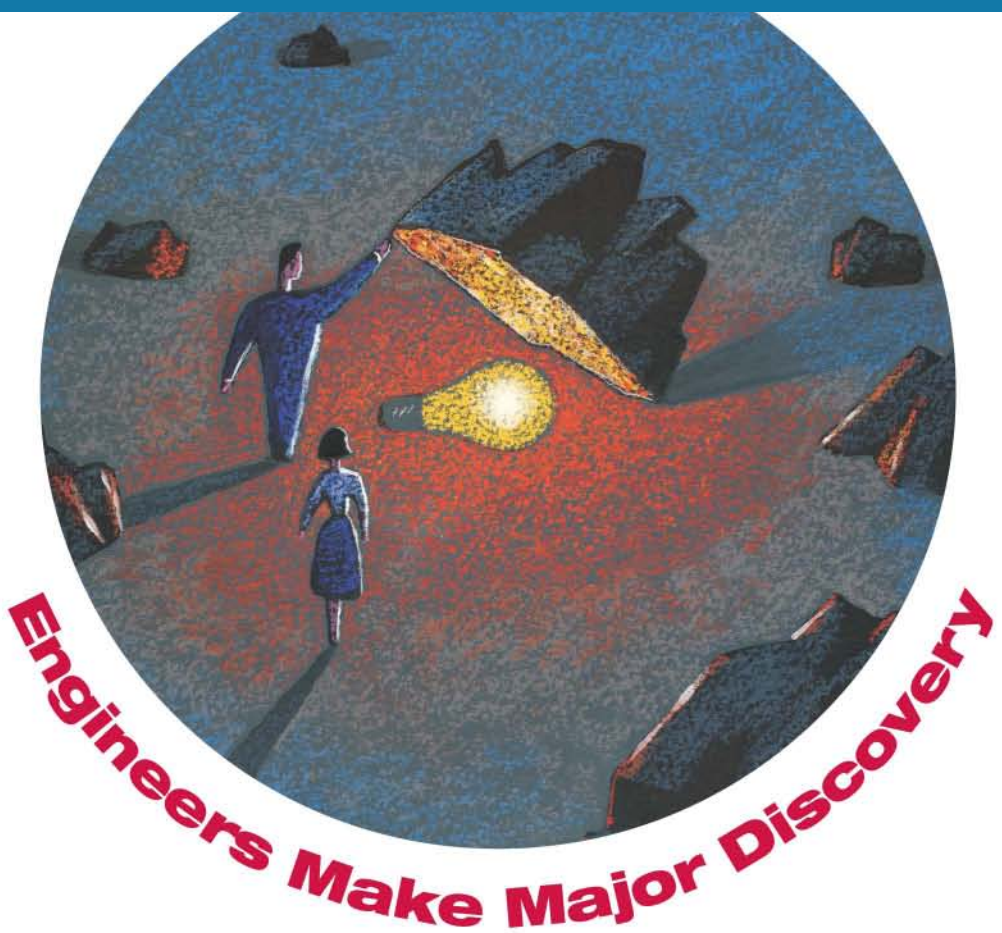


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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oil resources down dip at the Benita discovery on Block I, in late February.

Noble Energy is technical operator of Block I with 40% interest. Atlas Petroleum International Ltd. has 29%, Glencore Exploration Ltd. 25%, and Osborne Resources Ltd. 6%. State GEPetrol has a 5% carried interest once commerciality has been determined.

Peru's Ucayali gets big gas-condensate find

A group led by Repsol-YPF SA started production tests at a gas-condensate discovery on Block 57 in Peru's Ucayali basin.

Early test rates were 35.3 MMcfd and 1,245 b/d from 115 m of pay in an undisclosed formation, and partner Petroleo Brasileiro SA (Petrobras) said the 22-km-long Kinteroni structure's indicated a capacity of as much as 2 tcf of gas. Tests continued at the well is in Cuzco Province.

Repsol-YPF, with 41% interest, and Petrobras, with 35.15%, were in the process of acquiring the other 23.85% interest from ConocoPhillips's Burlington Resources Inc. subsidiary, subject to approval by Peruvian authorities.

Petrobras noted that the discovery well is near Blocks 58 and 110, which it is exploring with 100% interest.

Total starts Pazflor development work off Angola

Total SA, operator of Block 17, has awarded the principal contracts for the giant Pazflor oil development—the third development center on the offshore block, following Girassol and Dalia, both on production (OGJ, July 9, 2007, Newsletter).

Drilling operations are planned to start in 2009; oil production is slated to begin in 2011.

Pazflor, which lies in 600-1,200 m of water about 150 km offshore and 40 km northeast of Dalia field, involves bringing four fields into production: Perpetua, Hortensia and Zinia (Upper Miocene), and Acacia (Oligocene). The fields were discovered between mid-2000 and early 2003.

Pazflor covers 600 sq km with a north-south axis of more than 30 km. The overall development program uses well-tried techniques on Girassol and Dalia. A floating production, storage, and offloading unit for Pazflor production will process the oil via 49 subsea wells (25 producers, 22 water injectors, and 2 gas injectors). The FPSO will have a processing capacity of 200,000 b/d of oil and a storage capacity of 1.9 million bbl, bringing the installed production capacity on Block 17 to more than 700,000 b/d.

The Pazflor FPSO will handle two oils of very different characteristics: 17-22° gravity oil from Miocene reservoirs and 35-38° gravity oil from the Acacia Oligocene reservoir. Pazflor also will incorporate a number of technological advances in bringing difficult deep offshore fields into production, in particular, seabed gas-liquid separation, adjacent to the production wells. This technology is a world first.

Total E&P Angola holds a 40% interest in the block. It is partnered with StatoilHydro 23.33%, Esso Exploration Angola (Block 17) Ltd. 20%, and BP Exploration (Angola) Ltd. 16.67%.

Talisman makes oil, gas find off Vietnam

Talisman Energy Inc. has tested peak rates of 13,450 b/d of light oil and 6.87 MMcfd of natural gas from its second exploration well, Hai Su Den (HSD), off Vietnam.

HSD targeted a fractured basement reservoir and was drilled to a TVD of 11,168 ft, encountering a hydrocarbon-bearing interval of about 2,400 ft.

The results were constrained by test equipment, Talisman said. It described the discovery as "very promising" and offering a possible new development, as another discovery was made earlier in 2007 on the same block, 15-2/01. There also is the potential for upside from additional exploration wells.

Another four exploration wells are planned over the course of the year by Thang Long Joint Operating Co., a special purpose joint venture vehicle that will carry out all activities on the block. Activities will focus on evaluating features on trend with the HSD discovery.

Talisman holds a 60% working interest in any commercial discoveries on Block 15-2/01 with PetroVietnam Exploration & Production Co. holding the remaining 40%.

Block 15-2/01 is 50 miles off eastern Vietnam and is on trend with large oil and gas discoveries in the Cuu Long basin.

Trinidad and Tobago awards two exploration blocks

Trinidad and Tobago has announced the award of two exploration blocks to a consortium of Voyager Energy, Calgary, and Petrotrin.

The twin-island nation's Energy Minister Conrad Enill said the focus of the two production-sharing contracts is to explore and develop the Central Range shallow horizon block and the Central Range deep oil block.

Enill said Voyager had special expertise for exploring these blocks, which were "one of the more challenging areas on land."

Enill said the first phase includes the acquisition of seismic data and the drilling of four wells—three to 1,350 m on the shallow horizon block, and one to 3,650 m on the deep horizon block ✦

Drilling & Production — *Quick Takes*

Production starts from Kizomba C off Angola

ExxonMobil Corp. unit Esso Exploration Angola (Block 15) Ltd. has started oil production from the Kizomba C development on Block 15, about 90 miles off Angola. Kizomba C, which is designed to develop 600 million bbl of oil from the Mondo, Saxi and Batuque fields, lies in 2,400 ft of water.

The Kizomba C development has come on stream with Mondo field; Saxi and Batuque fields are expected to come on stream in 2008.

Mondo is expected to plateau at a peak production rate of 100,000 b/d. Plateau production from all three fields is expected to reach a total 200,000 b/d.

The Kizomba C development includes two floating production, storage, and offloading vessels and 36 subsea wells. The Kizomba C FPSO vessels are the fourth and fifth offshore pro-

duction hubs on Block 15.

Esso Angola serves as operator of Block 15, holding 40% interest. Its other block partners are BP Exploration (Angola) Ltd. 26.67%, Eni Angola Exploration BV 20%, and StatoilHydro Angola 13.33%.

Perenco to develop Peru heavy oil fields

Perenco, Paris, completed the acquisition of Barrett Resources (Peru) LLC, which owns three heavy oil fields set for development in the Maranon basin at a cost of $1.5 billion.

A development plan approved in July 2007 calls for oil production to start in January 2011 (OGJ, Aug. 20, 2007, Newsletter).

When developed, Paiche, Dorado, and Pirana fields on Block 67 have the capacity to produce as much as 100,000 b/d from more than 300 million bbl of proved and probable reserves, Perenco said.

The development plan calls for drilling, construction of surface processing and handling facilities, and pipelines to transport the oil to an existing pipeline that would itself require upgrading in a separate project.

Perenco Peru Ltd., which operates a similar project in Ecuador's Oriente, will participate in a continuing exploration program in the Peruvian region including the imminent start of a seismic survey on Block 121.

Shell starts gas production from Starling field

Royal Dutch Shell PLC has started natural gas production from Starling field in the central North Sea. It is expected to peak at 140 MMcfd of gas.

The field, developed under a £175 million investment plan, will export gas and liquids to the UK mainland. It is tied back to the Shearwater installation 33 km away.

Starling is on Block 29/3a in 100 m of water. ExxonMobil Corp. holds a 72% interest, and operator Shell holds 28%.

Last June both companies said they plan to sell several fields in the North Sea and are in confidential discussions with potential buyers. The partners, however, said they were prepared to continue investing in the right projects in this mature province.

Woodside lets EPC contract for Pluto platform

Woodside Energy has let a $24 million contract to the Eos joint venture for the design, engineering, procurement, and construction of its riser production platform for the Pluto LNG project off northwest Karratha, Western Australia.

The platform will export 1.6 bcfd of gas via a 36-in. subsea pipeline to an onshore single-train liquefaction plant having the capacity to produce 4.3 million tonnes/year of LNG.

Under the initial phase, Woodside will develop Pluto with five subsea big-bore wells with flowlines to the production platform that will be moored with risers in more than 275 ft of water.

Eos, a joint venture of KBR and WorleyParsons, has expanded the front-end engineering and design contract awarded in September 2006 into the engineering, procurement, and construction contract, with an option for execution services to include detailed design, procurement management services, and construction management assistance.

PTTEP to boost gas output via Arthit North FPSO

PTT Exploration & Production PLC (PTTEP) plans to ramp up its natural gas output from Arthit gas field in the Gulf of Thailand by 120 MMcfd, or 36%, to meet Thailand's rising gas demand.

In a 3-year program beginning in August, the extra production will come from sister field Arthit North.

Arthit North's output will supplement delivery from the main field, whose production of 330 MMcfd of gas and 22,000 b/d of condensate has been delayed by construction constraints until February (OGJ, May 12, 2006, Newsletter).

PTTEP will use a floating production, storage, and offloading vessel to support production startup at Arthit North. Development will include the installation of three well-head platforms, and the drilling of 27 development wells.

Gas production from Arthit North and the main Arthit is sold to parent PTT PLC, Thailand's largest petroleum group.

The country's 2008 gas consumption is expected to grow by 12.4% year-on-year to 3.9 bcf, according to the Thai Energy Ministry's latest forecast.

Colombia's La Creciente gas field starts up

Pacific Stratus Energy Ltd., Toronto, began delivering 35 MMcfd of gas on Dec. 28, 2007, from La Creciente field in Colombia's Lower Magdalena basin to the Guepaje-Sincelejo pipeline.

The company said its La Creciente D-1 discovery well identified a gas-bearing area of 430 acres. The well found the gas-water contact at 10,131 ft true vertical depth subsea, 32 ft below the top of the reservoir.

The well cut 28 ft of net reservoir sandstones with 18.1% average porosity and 38.8% average water saturation. Formation pressure at the top of the reservoir was 6,492 psi, or 150 psi lower than the pressure registered at the same depth on Prospect A.

The company said the Cienaga de Oro formation consists of 483 ft of well-sorted, coarse to fine grain sandstones (upper unit) and an interbedded sequence of silts, shales, and fine grain sandstones.

Meanwhile, Colombia's Agencia Nacional de Hidrocarburos awarded Pacific Stratus the Tacacho Technical Evaluation Agreement, which covers the 1.48 million acre Tacacho block in the foreland basin of the Putumayo mountain range in Colombia's Eastern Cordillera. The area lies along a prominent structural high that trends north-northwest from Ecuador.

The main exploration targets on the block are the Tertiary Pepino formation and Cretaceous Villeta sandstones, prolific producers in the Ecuadorian part of the basin.

US rig count down by 30 units

A total of 30 units dropped out of the US rotary rig count during the week ended Jan. 11, with 1,744 still working, up from 1,717 during the same period a year ago, Baker Hughes Inc. reported.

A cursory check of previous reports indicated it was the largest 1-week decline among US rigs since the period ended Jan. 26, 2007, when the count was down by 46 rigs. The latest loss cut through all three categories. Land drilling lost 17 units to 1,665. Inland water activity dropped 9 rigs to 20, and offshore drilling was down 4 to 59, including 57 in the Gulf of Mexico.

Louisiana had the biggest loss among major producing states, down 22 rigs to 139. Texas dropped 10 to 859; Oklahoma lost 7 to 190. New Mexico and California dropped 1 rig each to 69 and 42, respectively. Wyoming was unchanged with 73 rotary rigs drilling. On the other hand, Colorado's rig count increased by 4 to 103, and Alaska was up 1 to 7.

Meanwhile, with the seasonal cold improving movement of rigs, Canada's count jumped by 196 to 515 but was still below year-ago level of 586. ✦

Processing — *Quick Takes*

Sinclair settles refinery air pollution charges

Sinclair Oil Corp. agreed to pay a $2.45 million fine and spend more than $72 million to upgrade pollution controls as it settled federal charges that it violated the Clean Air Act at three of its refineries.

The US Department of Justice and Environmental Protection Agency jointly announced the settlement on Jan. 15. It involved alleged violations at Sinclair's refineries in Casper and Sinclair, Wyo., and in Tulsa.

Sinclair will be required to install new pollution controls at the plants that will reduce nitrogen oxide emissions by about 1,100 tons/year and sulfur dioxide discharges by nearly 4,600 tons/year when fully implemented, DOJ and EPA said in a joint announcement.

The new controls also will reduce emissions of volatile organic compounds and particulate matter from each of the refineries, the federal regulators added. They indicated that the three refineries have a total capacity of 160,000 b/d.

Sinclair also agreed to spend $150,000 on supplemental environmental projects in Oklahoma, including $100,000 to install new controls to reduce emissions of particulate matter from the City of Tulsa's municipal trash trucks, DOJ and EPA said.

They said Wyoming and Oklahoma joined in the consent decree and will share portions of the civil penalty with EPA. The consent decree, lodged in US District Court for the District of Wyoming, is subject to a 30-day comment period and approval by the federal court.

IPF group studying ethanol potential in diesel

Total SA of France and Brazil's Petroleo Brasileiro SA are part of the international consortium that Paris-based Institut Francais du Petrole (IFP) launched last spring to study the feasibility and utilization potential of ethanol for the production of diesel motor fuels, IFP said.

Called "Ethanol for Diesel," or E4D, the consortium also includes automobile manufacturers Renault and Sweden's VolvoPowertrain for the period covering 2007-09. E4D also is open to other partners.

Based on the expertise of IFP and the consortium partners, the research will study the impact of this type of motor fuel on the combustion process and on the optimization of engines in terms of performance and polluting emissions.

A solid base of experimental data could be established—a first step toward the direct incorporation of ethanol into the diesel chain, IPF said. Diversifying the types of motor fuels used in the diesel pool could, in the short term—and in the current context of the European market's strong dieselization trend—contribute to reestablishing the diesel-gasoline balance that is negatively impacting refinery streams.

It also could help reduce carbon dioxide emissions and the reliance on fossil fuels, IFP said. ✦

Transportation — *Quick Takes*

Sempra proposes gulf terminal, storage facility

Sempra Energy proposed construction of a marine petroleum terminal and storage facility in Port Arthur, Tex., to improve tanker access to refineries in Port Arthur and Beaumont.

San Diego, Calif.-based Sempra initiated an open-season solicitation for potential customers interested in purchasing terminal capacity.

An initial phase of the proposed terminal would provide storage and transportation for oil, liquefied petroleum gas, and related products. Vessels carrying oil and products to the Port Arthur region's refineries currently are limited by long, inner-waterway voyages restricted to daylight hours, Sempra said.

Its proposed terminal would allow 24-hr marine terminal access with an initial, first-phase throughput of up to 500,000 b/d. The project's first phase would require about 120 acres of the 2,900 acres Sempra Energy owns near Port Arthur.

The property also is the proposed site of a larger energy complex that includes the planned development of a LNG project capable of storing and regasifying up to 3 bcfd of gas.

The LNG terminal construction awaits Sempra's obtaining sufficient LNG supply and capacity agreements, the company said.

Uzbekistan approves Russian-Uzbek LNG venture

Uzbekistan's President Islam Karimov has approved the creation of a $221.5 million joint venture for the production of LNG by Russia's Stroytransgaz and Uzbekistan's Uzbekneftegaz.

A spokesman for Uzbekneftegaz said the president's approval clears the way for the planned signing of an agreement between the two companies by March of this year, aiming to produce LNG at the Mubarek natural gas processing plant.

The facility will process 12 billion cu m/year of gas and produce 270,000 tonnes of LNG along with 70,000 tonnes of gas condensate.

Stroytransgaz will contribute $110 million to the project, with an additional $45.5 million coming from Uzbekneftegaz, $35.5 million from Uzbekistan's Fund for Reconstruction and Development, and $30 million from an unnamed Chinese bank. ✦

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Letters

CAFE standards work

Your editorial, "More politics, less energy," was ridiculously dismissive of corporate average fuel economy (CAFE) standards (Dec. 24, 2007, p. 21). Some economists say that "lowering fuel mileage just encourages driving"? The best data show that increased driving might reduce the benefits of better fuel economy by about 10% at current income levels and less in the future. The weak response to the recent huge run-up in gasoline prices—driving rates didn't suffer all that much--demonstrates that driving is very insensitive to fuel costs per mile. And yes, the decision to allow light trucks to have a much more lenient standard than passenger cars opened up a gaping loophole that automakers drove right through—and there might be further surprises.

Regulations distort the market—does that mean we should never regulate? The reality is that the last set of standards, poorly structured as they were, still worked extremely well and succeeded in greatly reducing the amount of oil we would otherwise have used. The automakers' dire predictions—"we'd all be driving Pintos," etc.—failed to come to pass.

It is certainly true that ill-conceived regulations can have strong negative effects, but the 35 mpg target does not seem unreachable, and an intelligently designed new standard can be a major part of a US shift away from its current unsustainable course.

Steve Plotkin
Rockville, Md.

Calendar

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

OIL&GAS JOURNAL online

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

2008

JANUARY

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

API Exploration & Production Winter Standards

Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 21-25.

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

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

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

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

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

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

FEBRUARY

Middle East Corrosion Conference, Bahrain, + 973 17 729819, + 973 17 7299819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 3-6.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 5-6.

SPE Unconventional Reservoirs Conference, Keystone, Colo., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

International Pipeline Pigging & Integrity Management Conference & Exhibition, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 12-14.

Deep Offshore Technology International Conference & Exhibition, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 12-14.

SPE International Formation Damage Control Symposium & Exhibition, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 13-15.

Alternative Fuels Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 18.

IP Week, London, +44 (0)20 7467 7100, +44 (0)20 8561 0131 (fax), e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 18-21.

International Catalyst Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 19-20.

Pipe Line Contractors Association Annual Conference (PLCA), Maui, (214) 969-2700, (214) 969-2705 (fax), e-mail: plca@plca.org, website: www.plca.org. 20-24.

International Petrochemicals & Gas Technology Conference & Exhibition, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 21-22.

AAPG Southwest Section Meeting, Abilene, Tex., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-27.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 24-27.

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 25-26.

CERI Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 25-26.

SPE Intelligent Energy Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 25-27.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Kuala Lumpur, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 26-27.

Middle East Fuels Symposium, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 27-28.

MARCH

GPA Annual Convention, Grapevine, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 2-5.

GEO Middle East Geosciences Conference & Exhibition, Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com. 3-5.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 4-5.

ARTC Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 4-6.

Global Petrochemicals Annual Meeting, Dusseldorf, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

IADC/SPE Drilling Conference & Exhibition, Orlando, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 4-6.

SPE Indian Oil & Gas Technical Conference & Exhibition, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

Annual Middle East Gas Summit, Doha, +971 4 336 2992, +971 4 336 0116 (fax), e-mail: sarita.singh@ibc-gulf.com, website: www.ibcgulfconferences.com. 5-6.

Calendar

NPRA Annual Meeting, San Diego, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-11.

World Heavy Oil Congress, Edmonton, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

New Zealand Petroleum Conference, Auckland, +64 3 962 6179, +64 4 471 0187 (fax), e-mail: crown.minerals@med.govt.nz, website: www.crownminerals.govt.nz. 10-12.

Gastech International Conference & Exhibition, Bangkok, +44 (0) 1737 855005, +44 (0) 1737 855482 (fax), e-mail: tonystephenson@dmgworldmedia.com, website: www.gastech.co.uk. 10-13.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 10-14.

European Fuels Conference & Annual Meeting, Paris, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 11-12.

IADC International Deepwater Drilling Conference & Exhibition, Rio de Janeiro, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

SPE North Africa Technical Conference & Exhibition, Marrakech, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

NACE International Conference & Expo, New Orleans, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org. 16-20.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 17-19.

Sub-Saharan Oil, Gas & Petrochemical Exhibition & Conference, Cape Town, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: expo@fairconsultants.com, website: www.fairconsultants.com. 17-19.

Turoge and Black Sea Oil & Gas Exhibition & Conference, Ankara, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 18-20.

AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

✦PIRA Understanding Global Oil Markets Conference, Tokyo, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. Mar. 31-Apr. 1.

ERTC Sustainable Refining Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Mar. 31–Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

ERTC Biofuels+ Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

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

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

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

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

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

WestAsia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

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

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

✦SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs, Va., (713) 651-1639, (713) 951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

Calendar

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

✦Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

✦Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

PIRA's Globalization of Gas Study Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 25.

PIRA Understanding Natural Gas Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 26-27.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

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

Colorado Oil & Gas Association Conference, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

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

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

AUGUST

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

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

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

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

SEPTEMBER

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

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NOVEMBER

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

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

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

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

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

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

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

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

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

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

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

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

DECEMBER

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

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

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

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

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

$100 oil and cheap cars

Sam Fletcher
Senior Writer

Two events occurred in January that could have a major effect on the oil industry—the first $100/bbl sales of crude and the unveiling of the world's cheapest car, said John Westwood, managing director of the UK consultancy Douglas-Westwood Ltd., at a Jan. 10 meeting with industry representatives in Houston.

To some financial analysts, the initial intraday spike of crude to $100/bbl Jan. 2 on the New York Mercantile Exchange was just another effort "to manipulate markets." Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, earlier dismissed that first sale as "a controversial one-lot transaction done on the floor away from computer trading." Westwood said the 1,000 bbl contract later was resold at a loss of 60¢/bbl. Meanwhile, he said, "The world went berserk" as economists, politicians, and the general public railed against high oil prices.

Crude hit a second intraday high of $100.09/bbl Jan. 3 on NYMEX before slipping lower amid concerns of economic weaknesses. "Technically the positive momentum is still valid and the risk remains for a strong advance when and if [a closing price of] $100/bbl is broken," Jakob said at that time. But in subsequent sessions, crude traded in a $7/bbl band below the magical $100 mark.

Economic and population growths have been the fundamentals behind high oil prices, said Westwood. Developed nations—"even the US"—reduced energy consumption in 2006, but energy demand has continued strong growth among emerging economies.

World's cheapest car

That demand could grow even stronger with the Jan. 10 unveiling of the world's cheapest car at the 9th Auto Expo in New Delhi—a four-door, five-seat automobile designed to sell for $2,500 vs. $4,000 for the current low-cost car available in India. Tata Motors, India's largest automobile company and part of the Tata Group, India's largest private sector conglomerate, spent 4 years developing the Nano or "people's car," primarily by eliminating many of the features that over the years have become standard on most modern autos, particularly those manufactured in Europe, Japan, and the US.

The Nano has no radio, power steering, power windows, tachometer, air conditioning, or other such comforts, of course, and its trunk can't hold much more than a briefcase. It has only one windshield wiper and an analog speedometer that could be kilometers-per-hour less accurate that a digital unit. Using a hollow rolled-metal tube to connect its steering wheel to the steering system eliminates the extra cost and weight of a solid metal bar. It's powered by a rear-mounted all-aluminum, two-cylinder 623 cc gasoline-fueled engine, producing a teardrop body shape that reduces wind resistance. Its continuous variable transmission, utilizing pulleys instead of gears, is sluggish but lighter and cheaper than manual or automatic units. Some parts of the car are held together by adhesives instead of metal bolts, and the use of lighter bearings and metals may mean the vehicle cannot withstand long or heavy use.

The company claims Nano's tailpipe emissions pass India's current requirements, although it doesn't approach US standards. Still, company officials say it has a lower pollution level than the bipeds, scooters, and motorcycles that comprise the bulk of motor vehicles in India. Company officials claim its fuel efficiency ensures lower carbon dioxide emissions. But others doubt it can meet the Euro IV emissions standard that India's major cities are to adopt in 2010.

Safety features aren't up to Western standards but may be an improvement over the two-wheelers. Ratan N. Tata, group chairman, said he got the idea of a cheap car after observing families riding on two-wheelers—the father driving the scooter, his young child standing in front of him, his wife seated behind holding a baby.

World's largest markets

India is now the second-fastest growing car market in Asia, after China.

With a population of more than 1 billion, India now has 12 motor vehicles per every 100 people. Tata expects the Nano to improve that ratio. Meanwhile, the Renault-Nissan combination is already planning an ultracheap car for that market as is the Indian-Japanese joint venture Maruti Suzuki. With the potential increase in the demand for oil and resulting pollution, Westwood advises, "Go see the Taj Mahal before it disappears in a cloud of exhaust."

Meanwhile, China has a population of more than 1.3 billion people, but only 10 motor vehicles per 100. If a similar cheap auto were to be introduced into that market, the Great Wall also might fade from sight. ✦

Editorial

Winning back public trust

The report by a special commission on US transportation issues offers the oil and gas industry a chance to assert its commitment to consumer interests. It's a chance to rebuild trust with the American public. It's a chance, therefore, for the industry to recover some of its lost voice in US energy politics.

The National Surface Transportation Commission, established by Congress in 2005, proposes to raise the federal gasoline tax by as much as 40¢/gal within 5 years to fund highway and bridge repair. As aggressively as it can, the industry should oppose this initiative.

Thoughtful people in the industry will see reasons to take the other position. The aging US transportation system surely needs work. The work requires money. Public safety is at stake. As a side benefit, the elevated fuel cost would help ease demand pressure now straining supply systems and lifting fuel prices. Reducing consumption would lower emissions of air pollutants and greenhouse gases.

Those arguments are appealing as far as they go. They just shouldn't come from the oil and gas industry.

Consumer interests

The industry position should be unalloyed opposition to any policy that raises fuel prices for reasons other than market dynamics. The industry should take this position and defend it consistently for one reason: concern for the interests of its customers. Those customers are energy consumers. They pay taxes. They vote. And too many of them now thoroughly distrust the oil and gas industry.

There are other reasons to oppose the commission's recommendations. Prominent among them is the approach: addressing public problems by raising taxes, spending money, and expanding the federal bureaucracy. The US government needs to spend less money, not more. It needs to cut taxes, not raise them.

If the government met reasonable standards of fiscal responsibility, discussion of special taxation to solve a specific problem might be in order. The government is in fact spendthrift. Its legislative branch channels huge amounts of public money to preferred constituencies through earmarks and subsidies. Until recently, its chief executive has been too reluctant to use his veto to control the damage. Until fiscal discipline makes an appearance in Washington, DC, new taxation should be out of the question.

What's more, the main reason the industry has lost influence in energy policy-making is that much of the public blames it for painfully high prices of gasoline and other oil products. The popular assumption is that the industry controls oil prices. The assumption is false. If the industry had that much power over prices it would have bailed itself out of the troubles it endured in the latter 1980s and most of the 1990s. Markets, which the oil industry can't control, set oil prices. Pretending otherwise to exploit antique suspicions, however, is an expedient political tactic. So opportunistic politicians perpetuate falsehood to the detriment of public trust in a crucial industry.

If it were possible for the industry to raise oil prices at will, and if doing so was by its nature evil, why would it not be just as evil for the government to effectively lift prices by hiking taxes? The effect on consumers is the same. A different way of asking the question, grounded more firmly in how things really work, is this: Why should consumers (who also pay taxes and vote) find fuel-cost increases acceptable when they're instigated by the government but not when they result from changes in markets, which no one controls and about which no one can do much except adapt?

Regaining stature

While these are sound objections to a bad idea, the oil and gas industry shouldn't bother making them. It should confine its response to the pain energy consumers would sustain from the proposed hike in gasoline taxes. And it should begin now to approach every energy issue from the same perspective.

Opposing a gasoline tax hike on the basis of consumer interest can help the industry win back public trust. That's essential if the industry is to regain the stature it deserves in the making of energy policy. ✦

Energy demand to grow slowly worldwide, stagnate in the US

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

US energy demand in 2008 will be nearly unchanged from last year. Weakness in the US economy, in addition to a global economic slowdown, will hold growth in check.

Demand for natural gas will grow modestly in the US, and there will be a small uptick in the use of renewable energy this year. But the use of all other forms of energy will decline or hold steady from 2007.

Oil prices will moderate this year, but conservation will come into play as consumer spending power weakens as the economy slows. Demand for most oil products in the US will decline.

Last year's high oil prices were attributed to a host of factors, including the weak US dollar, limited spare production capacity, geopolitical tensions, and rising demand in China, India, and other developing economies.

Global oil demand

OGJ forecasts that a weakening global economy will hold worldwide oil demand growth to 1.8% this year, with consumption averaging 87.2 million b/d. Most demand growth will occur outside the Organization for Economic Cooperation & Development.

North American oil demand will be unchanged from the International Energy Agency's 2007 demand estimate of 25.5 million b/d. Meanwhile, demand growth in the European member countries of the OECD will inch up 0.8% to 15.4 million b/d for the year.

Weakening after averaging 9.2 million b/d in the first quarter of 2008, average OECD Asia-Pacific demand will climb to 8.5 million b/d from 8.3 million b/d last year.

Outside the OECD, demand will increase 3.5% this year, averaging 37.8 million b/d. China and the former Soviet Union will lead this year's growth, each with annual gains of about 5%. But demand growth in China will wane following this year's Olympic Games.

Most other regions also will post demand gains from 2007, but non-OECD Europe demand will be unchanged at 800,000 b/d.

Worldwide oil supply

Crude supply this year will climb nearly 3%, allowing stocks to build.

Gains in natural gas liquids production will combine with a small increase in crude output from members of the Organization of Petroleum Exporting Countries, as well as rising production in the former Soviet Union, China, and Brazil this year. Supply and demand estimates for Ecuador, which rejoined

OPEC at the start of 2008, are still included in non-OPEC figures in this report.

Total oil supply this year will average 88 million b/d. Supply from the OECD countries will decline 1.5% this year to average 19.5 million b/d. Australia will record production growth this year, but supply from North America and Europe will fall.

Combined oil output from the former Soviet Union will average 13.2 million b/d, according to IEA. Last year these countries' production averaged 12.7 million b/d.

The Paris-based agency also estimates that processing gains will hold at 2.1 million b/d this year but that supply of biofuels and fuel ethanol from outside the US and Brazil will increase to 700,000 b/d from 400,000 b/d last year. This puts the forecast for all non-OPEC supply at 51.3 million b/d for 2008, up 2.2%.

For the fourth quarter of 2007, OGJ estimates that OPEC production was 31.2 million b/d, making the organization's crude output average 30.5 million b/d for the year.

With weakening worldwide demand, slightly lower oil prices, and increases elsewhere, OPEC output will be little changed over 2008. OGJ expects OPEC crude production to average 31.3 million b/d this year. Combined with the 5.4 million b/d of NGL that IEA expects from OPEC, stocks will build 800,000 b/d.

Worldwide supply and demand

	2007 1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year	2008 1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year
	Million b/d									
Demand										
OECD										
North America	25.7	25.4	25.6	25.4	25.5	25.7	25.3	25.5	25.5	25.5
Europe	15.2	15.0	15.4	15.7	15.3	15.4	15.2	15.5	15.6	15.4
Asia/Pacific	8.8	7.8	7.8	8.9	8.3	9.2	7.9	8.0	9.0	8.5
Total OECD	**49.7**	**48.2**	**48.8**	**50.0**	**49.2**	**50.3**	**48.4**	**49.0**	**50.1**	**49.5**
Non-OECD										
FSU	3.9	3.7	3.9	4.2	3.9	4.1	3.8	4.0	4.3	4.1
Europe	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8
China	7.3	7.7	7.5	7.7	7.5	7.6	8.0	7.8	8.0	7.9
Other Asia	9.2	9.2	9.0	9.2	9.1	9.4	9.4	9.2	9.4	9.3
Latin America	5.4	5.6	5.6	5.5	5.5	5.5	5.7	5.8	5.7	5.7
Middle East	6.4	6.6	6.8	6.5	6.6	6.8	6.9	7.1	6.8	6.9
Africa	3.1	3.1	3.0	3.1	3.1	3.2	3.2	3.1	3.2	3.2
Total Non-OECD	36.1	36.6	36.5	36.9	36.5	37.4	37.8	37.7	38.2	37.8
Total Demand	**85.5**	**84.7**	**85.3**	**86.9**	**85.7**	**87.7**	**86.2**	**86.7**	**88.3**	**87.2**
Supply										
OECD										
North America	14.4	14.4	14.2	14.2	14.3	14.4	14.1	14.0	14.1	14.2
Europe	5.2	4.9	4.7	4.8	4.9	4.8	4.5	4.3	4.5	4.5
Asia	0.6	0.6	0.6	0.7	0.6	0.8	0.8	0.8	0.9	0.8
Total OECD	**20.2**	**19.9**	**19.5**	**19.8**	**19.8**	**20.0**	**19.3**	**19.1**	**19.5**	**19.5**
Non-OECD										
FSU	12.7	12.7	12.7	12.8	12.7	13.0	13.1	13.2	13.5	13.2
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.7	3.8	3.7	3.8	3.8	3.9	3.9	3.9	3.9	3.9
Other Asia	2.7	2.7	2.6	2.7	2.7	2.7	2.8	2.8	2.9	2.8
Latin America	4.4	4.4	4.4	4.4	4.4	4.6	4.7	4.7	4.7	4.7
Middle East	1.7	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.6
Africa	2.6	2.5	2.5	2.6	2.6	2.7	2.7	2.7	2.7	2.7
Total Non-OECD	**27.9**	**27.8**	**27.7**	**28.1**	**27.9**	**28.6**	**28.9**	**29.0**	**29.3**	**29.0**
Processing gain	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.1
Other biofuels	0.4	0.4	0.4	0.5	0.4	0.6	0.7	0.7	0.7	0.7
Total Non-OPEC	**50.4**	**50.2**	**49.7**	**50.5**	**50.2**	**51.3**	**51.0**	**51.0**	**51.8**	**51.3**
OPEC										
Crude	30.2	30.1	30.6	31.2	30.5	31.3	31.4	31.2	31.2	31.3
NGL	4.8	4.8	4.8	5.0	4.8	5.1	5.3	5.5	5.8	5.4
Total OPEC	**35.0**	**34.9**	**35.4**	**36.2**	**35.3**	**36.4**	**36.7**	**36.7**	**37.0**	**36.7**
Total supply	**85.4**	**85.1**	**85.1**	**86.7**	**85.5**	**87.7**	**87.7**	**87.7**	**88.8**	**88.0**
Stock change	(0.4)	0.4	(0.2)	(0.2)	(0.2)	—	1.5	1.0	0.5	0.8

Totals may not add due to rounding.
Source: International Energy Agency for all 2007 and for 2008 supply, OGJ estimates for 2008 demand.

US economy, energy

With help from the Federal Reserve in the form of lower interest rates, the US will narrowly avoid slipping into a recession for the year. Growth in 2008 will be shallow to nil in the first half, but a small upturn will materialize in the third and fourth quarters.

OGJ forecasts that US gross domestic product will grow a meager 1.8% this year, compared with 2.2% growth for 2007.

Employment weakness appeared in August of last year—the first monthly decline in the employment rate in 4 years—and 2007 was the weakest year for job growth over the same period. Drops in construction and manufacturing payrolls revealed that the housing

US energy demand

	2006	2007	Change, % 2007/06	2008	Change, % 2008/07	% share of total energy 2006	2007	2008
	Trillion btu			Trillion btu				
Oil	39,958	40,000	0.1	39,840	–0.4	40.0	39.6	39.4
Gas	22,190	22,850	3.0	23,190	1.5	22.2	22.6	23.0
Coal	22,452	22,900	2.0	22,775	–0.5	22.5	22.7	22.5
Nuclear	8,214	8,300	1.0	8,300	—	8.2	8.2	8.2
Hydro, other	6,999	6,860	–2.0	6,900	0.6	7.0	6.8	6.8
Total	**99,813**	**100,910**	**1.1**	**101,005**	**0.1**	**100.0**	**100.0**	**100.0**

Sources: 2006 US Energy Information Administration; 2007 and 2008 OGJ estimate and forecast

OGJ FORECAST OF US SUPPLY AND DEMAND

	Year 2008 Volume 1,000 b/d	Year 2008 % change from 2007	Year [1]2007 Volume 1,000 b/d	Year [1]2007 % change from 2006
DOMESTIC DEMAND				
Motor gasoline	9,270	–0.4	9,305	0.6
Dist. 1–4	7,633	–0.4	7,662	0.6
Dist. 5	1,637	–0.4	1,643	0.6
Jet fuel	1,620	–0.1	1,622	–0.7
Dist. 1–4	1,130	–0.1	1,131	–0.7
Dist. 5	490	–0.1	491	–0.7
Distillate	4,300	1.1	4,254	2.0
Dist. 1–4	3,710	1.1	3,670	2.0
Dist. 5	590	1.1	584	2.0
Residual	720	–2.8	741	7.5
Dist. 1–4	552	–2.8	568	7.5
Dist. 5	168	–2.8	173	7.5
LPG and ethane	2,050	–0.5	2,060	0.4
Dist. 1–4	1,998	–0.5	2,008	0.4
Dist. 5	52	–0.5	52	–1.5
Other products	2,650	–2.5	2,718	–6.0
Dist. 1–4	2,378	–2.5	2,439	–6.0
Dist. 5	272	–2.5	279	–5.7
TOTAL DOMESTIC DEMAND	**20,610**	**–0.4**	**20,700**	**0.1**
Dist. 1–4	17,401	–0.4	17,478	0.0
Dist. 5	3,209	–0.4	3,222	0.4
EXPORTS	**1,400**	**3.2**	**1,356**	**3.0**
Dist. 1–4	1,161	3.2	1,124	3.0
Dist. 5	239	3.2	232	3.4
TOTAL DEMAND	**22,010**	**–0.2**	**22,056**	**0.2**
Dist. 1–4	18,561	–0.2	18,602	0.2
Dist. 5	3,449	–0.1	3,454	0.6
SUPPLY				
DOMESTIC PRODUCTION				
Crude & condensate	5,135	0.4	5,114	0.2
Dist. 1–4	3,700	0.4	3,685	0.2
Dist. 5	1,435	0.4	1,429	0.2
NGL and LRG[2]	1,760	0.6	1,750	0.6
Dist. 1–4	1,693	0.6	1,684	0.6
Dist. 5	67	0.6	66	0.6
Total domestic production	6,895	0.5	6,864	0.3
Dist. 1–4	5,393	0.5	5,368	0.4
Dist. 5	1,502	0.4	1,496	0.3
IMPORTS				
Crude oil	9,950	–0.5	10,003	–1.1
Dist. 1–4	8,796	–0.5	8,843	–1.1
Dist. 5	1,154	–0.5	1,160	–1.1
Products & unfinished oils	3,450	–1.3	3,495	–2.6
Dist. 1–4	3,151	–1.3	3,192	–2.6
Dist. 5	299	–1.3	303	–2.6
TOTAL IMPORTS	**13,400**	**–0.7**	**13,498**	**–1.5**
Dist. 1–4	11,948	–0.7	12,035	–1.5
Dist. 5	1,452	–0.7	1,463	–1.4
Processing gain, loss, etc.	1,700	10.5	1,538	50.8
Dist. 1–4	1,372	10.5	1,241	50.8
Dist. 5	328	10.5	297	50.8
TOTAL NEW SUPPLY	**21,995**	**0.4**	**21,900**	**1.5**
Dist. 1–4	18,712	0.4	18,645	1.4
Dist. 5	3,283	0.8	3,255	2.6
STOCK CHANGE	**(15)**	**—**	**(156)**	**—**
Dist. 1–4	151	—	42	—
Dist. 5	(166)	—	(198)	—
CRUDE RUNS TO STILLS	**15,400**	**0.1**	**15,382**	**0.9**
TOTAL INPUT TO STILLS	**15,600**	**0.1**	**15,584**	**–0.1**
TOTAL REFINING CAPACITY	**17,500**	**0.4**	**17,436**	**0.3**
REFINING UTILIZATION, %	**89.1**	**–0.3**	**89.4**	**–0.4**
TOTAL INDUSTRY STOCKS[3]	**969**	**–0.5**	**974**	**–5.5**
Refined products	684	–0.3	686	119.9
Crude oil	285	–1.0	288	–59.9
SPR crude oil stocks	700	0.6	696	1.0
IMPORT DEPENDENCY				
Total imports % domestic demand	65.0		65.2	
Net imports % domestic demand	58.2		58.7	

[1]Preliminary estimate. [2]Liquefied refinery gases. [3]Million bbl at end of period.

crunch hurt the economy.

Workers' earnings gained slightly at the end of last year, but inflation for the first 11 months of the year was 4.2%, according to the Bureau of Labor Statistics. This compares with inflation of 2.5% for all of 2006.

The consumer price index for energy, which increased 2.9% in 2006, advanced at an 18.1% seasonally adjusted annual rate in the first 11 months of 2007. Petroleum-based energy costs increased at a 30.8% annual rate, and charges for energy services rose at a 3.2% annual rate, BLS reported.

The economic slowdown and conservation will keep energy demand growth negligible—to 101.005 quadrillion btu (quads) from 100.91 quads last year.

Energy by source

Consumption of oil and coal will decline slightly this year in the US while the use of natural gas and renewable energy grows slightly.

Natural gas demand will climb to 23.19 quads, bringing the gas energy market share to 23%, higher than coal's 22.5%.

Coal demand this year will decline by 0.5% following a 2% power generation-led gain during 2007. The use of nuclear energy will be unchanged at 8.3 quads. Last year's increase in energy demand drove the use of nuclear energy in the US up 1% to its highest annual level.

Demand for alternative energy sources, including hydroelectric power generation, solar, and wind energy, will climb only 0.6% this year, following a 2% decline last year. These renewable energy sources account for just below 7% of the US energy market.

Oil demand this year will be down 0.4% from 2007, totaling 39.84 quads. Last year's use of oil products was up negligibly to 40 quads. Strong prices have encouraged efficiency in the use of jet fuel and motor gasoline. And the use of oil products as petrochemical feedstocks has been on a downward trend in the US.

Combined, oil and natural gas will comprise 62.4% of the US energy market this year, up slightly from a year ago.

Oil supply

The 2007 and 2008 start-ups of some major upstream projects will help boost US crude and condensate production to an average 5.135 million b/d this year.

This year's expected start-ups include Thunder Hawk, Thunder Horse, and Tahiti in the Gulf of Mexico (OGJ, July 23, 2007, p. 43). These big oil-producing fields join Atlantis and Neptune, which are already on stream. Combined, the five fields' peak production will exceed 1 million b/d.

Oil production increased slightly last year to 5.114 million b/d, according to OGJ estimates, from 5.102 million b/d in 2006.

During 2007, a large gain in production in Louisiana mostly offset declines in a handful of other states. Oklahoma, Texas, Colorado, and California incurred dips in production last year, while Louisiana production averaged 1.34 million b/d, up more than 5% from a year earlier.

Alaskan oil production declined last year to average 720,000 b/d, down from 741,000 b/d in 2006 and 864,000 b/d in 2005. Crude and condensate production in Alaska hasn't increased since 2002, when average output climbed to 988,000 b/d from 963,000 b/d in 2001.

OGJ forecasts that average NGL production this year will rise to 1.76 million b/d from 1.75 million b/d last year and 1.739 million b/d a year earlier.

Inventories

Stocks of crude and products finished 2007 lower than a year earlier. Crude inventories closed out the year down more than 8% to a level able to meet refinery needs for 19 days. At yearend 2006, crude supplies stood at more than 20 days of refinery inputs.

Total motor gasoline inventories were down slightly at the end of 2007, and jet fuel stocks were up marginally. Inventories of residual fuel oil and other oil products finished last year lower.

But distillate stocks, especially high-sulfur distillate inventories, were much lower from a year earlier. High-sulfur

US NATURAL GAS SUPPLY AND DEMAND

	2005	2006	2007	Change, % 07/06	2008	Change, % 08/07
	bcf				bcf	
Marketed production						
Texas	5,276	5,514	5,920	7.4	6,100	3.0
Louisiana	1,296	1,361	1,320	–3.0	1,335	1.1
Federal Gulf of Mexico	3,132	2,902	2,727	–6.0	2,820	3.4
Other states	9,223	9,605	9,533	–0.7	9,445	–0.9
Total production	**18,927**	**19,382**	**19,500**	**0.6**	**19,700**	**1.0**
Imports						
Canada	3,700	3,590	3,600	0.3	3,580	–0.6
Mexico	9	13	50	284.6	50	0.0
LNG	631	584	780	33.6	800	2.6
Total imports	**4,341**	**4,186**	**4,430**	**5.8**	**4,430**	**0.0**
Supplemental gas	64	66	55	–16.7	65	18.2
Losses, etc.*	(644)	(821)	(1,100)	34.0	(750)	–31.8
Total new supply	**22,688**	**22,813**	**22,885**	**0.3**	**23,445**	**2.4**
Supply from storage	52	(436)	(170)	139.0	—	—
Total supply	**22,740**	**22,377**	**23,055**	**3.0**	**23,445**	**1.7**
Exports	729	724	750	3.6	800	6.7
Total consumption	**22,011**	**21,653**	**22,305**	**3.0**	**22,645**	**1.5**

*Extraction losses and unaccounted–for gas.
Sources: 2005 and 2006 US Energy Information Administration. 2007 and 2008 OGJ estimates and forecast

OIL, GAS, PRODUCTS PRICES

	Crude oil		Products		Natural gas	
Year	Average US wellhead price	Average landed cost of imports	Unleaded gasoline pump price	No. 2 fuel oil wholesale price	Average US wellhead price	Average delivered commercial price
	$/bbl		¢/gal		$/Mcf	
1976	8.19	13.32	61.4	NA	0.58	1.64
1977	8.57	14.36	65.6	NA	0.79	2.04
1978	9.00	14.35	67.0	36.9	0.91	2.23
1979	12.64	21.45	90.3	56.9	1.18	2.73
1980	21.59	33.67	124.5	80.3	1.59	3.39
1981	31.77	36.47	137.8	97.6	1.98	4.00
1982	28.52	33.18	129.6	91.4	2.46	4.82
1983	26.19	28.93	124.1	81.5	2.59	5.59
1984	25.88	28.54	121.2	82.1	2.66	5.55
1985	24.09	26.67	120.2	77.6	2.51	5.50
1986	12.51	13.49	92.7	48.6	1.94	5.08
1987	15.40	17.65	94.8	52.7	1.67	4.77
1988	12.58	14.08	94.6	47.3	1.69	4.63
1989	15.86	17.68	102.1	56.5	1.69	4.74
1990	20.03	21.13	116.4	69.7	1.71	4.83
1991	16.54	18.02	114.0	62.2	1.64	4.81
1992	15.99	17.75	112.7	57.9	1.74	4.88
1993	14.25	15.72	110.8	54.4	2.04	5.22
1994	13.19	15.18	111.2	50.6	1.85	5.44
1995	14.62	16.78	114.7	51.1	1.55	5.05
1996	18.46	20.31	123.1	63.9	2.17	5.40
1997	17.23	18.11	123.4	59.0	2.32	5.80
1998	10.88	11.84	105.9	42.2	1.96	5.48
1999	15.56	17.23	116.5	49.3	2.19	5.33
2000	26.72	27.53	151.0	88.6	3.68	6.59
2001	21.84	21.82	146.1	75.6	4.00	8.43
2002	22.51	23.91	135.8	69.4	2.95	6.63
2003	27.56	27.69	159.1	88.1	4.88	8.40
2004	36.77	36.07	188.0	112.5	5.46	9.43
2005	50.28	49.29	229.5	162.3	7.33	11.34
2006	59.69	59.11	258.9	183.4	6.40	11.99
*2007	67.00	65.00	280.0	197.0	6.33	11.30

*Estimated.
Sources: 1976-2006 US Energy Information Administration; 2007 OGJ estimates

US PRODUCTION OF CRUDE OIL AND LEASE CONDENSATE

	[1]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	Cumulative 1859-2007 1,000 bbl
	1,000 b/d										
District 1:											
Fla., N.Y., Pa., W. Va.	21	22	23	19	20	20	20	21	22	26	2,793,900
Total Dist. 1	**21**	**22**	**23**	**19**	**20**	**20**	**20**	**21**	**22**	**26**	**2,793,900**
District 2:											
Illinois	30	28	28	30	32	34	28	33	33	38	3,622,671
Indiana	5	5	5	5	5	5	6	6	5	6	555,331
Kansas	99	98	93	93	93	86	93	94	80	97	6,334,867
Kentucky	7	6	7	7	7	8	8	9	8	8	779,737
Michigan	16	14	15	18	18	24	20	22	21	25	1,263,964
Nebraska	6	6	7	7	8	8	8	8	7	9	503,284
North Dakota	115	109	98	85	81	85	87	89	90	97	1,572,488
Ohio	15	15	15	16	15	20	17	18	16	18	1,113,944
Oklahoma	168	172	170	171	179	183	188	192	193	213	14,593,505
Others[2]	5	5	5	4	4	3	4	4	4	4	67,260
Total Dist. 2	**466**	**458**	**443**	**436**	**442**	**456**	**459**	**475**	**457**	**515**	**30,407,051**
District 3:											
Alabama	19	21	22	20	22	24	26	29	30	34	645,331
Arkansas	17	17	17	18	20	21	21	20	20	22	1,782,165
Louisiana	1,340	1,272	1,061	1,470	1,562	1538	1,620	1,534	1,513	1,432	29,385,311
Mississippi	54	48	48	47	45	51	54	54	49	60	2,333,595
New Mexico	162	164	166	176	181	183	186	184	176	198	5,337,247
Texas	1,315	1,317	1,489	1285	1,356	1418	1,364	1,394	1,400	1,547	62,353,031
Total Dist. 3	**2,907**	**2,839**	**2,803**	**3,016**	**3,186**	**3,235**	**3,271**	**3,215**	**3,188**	**3,293**	**101,836,680**
District 4:											
Colorado	46	64	63	60	58	40	45	50	51	61	1,971,068
Montana	90	99	90	68	53	43	44	42	41	45	1,623,996
Utah	51	49	46	40	36	41	42	43	45	53	1,320,003
Wyoming	145	145	141	141	144	153	157	166	167	178	6,960,880
Total Dist. 4	**332**	**357**	**340**	**309**	**291**	**277**	**288**	**301**	**304**	**337**	**11,875,947**
District 5:											
Alaska	720	741	864	908	974	988	963	971	1,050	1,175	16,097,979
California	667	684	704	730	767	797	799	837	857	904	27,681,159
Nevada	1	1	1	1	1	2	2	2	2	2	51,821
Total Dist. 5	**1,388**	**1,426**	**1,569**	**1,639**	**1,742**	**1,787**	**1,764**	**1,810**	**1,909**	**2,081**	**43,830,959**
US total	**5,114**	**5,102**	**5,178**	**5,419**	**5,681**	**5,775**	**5,802**	**5,822**	**5,880**	**6,252**	**190,744,426**

[1]Preliminary. [2]Includes Missouri, South Dakota, and Tennessee.

(more than 500 ppm) distillate, ended last year down 36%, while ultralow-sulfur distillate stocks climbed 17% from a year earlier.

The amount of crude oil in the Strategic Petroleum Reserve climbed slowly throughout the year and stood at 696 million bbl at the end of 2007. OGJ expects the SPR to end 2008 at 700 million bbl.

Refining

Refining activity will decline slightly again this year, after the average utilization rate for 2007 decreased to 89.4% from 89.7% a year earlier.

Capacity utilization hovered just below 90% throughout much of 2007 because of maintenance and temporary shutdowns. Last year was a busy year for maintenance and turnarounds because refiners had delayed such work for about 2 years to take advantage of high margins.

US refiners' acquisition costs for crude rose sharply last year, especially costs for imported crude. Refiners paid about 12% more for domestic crude during 2007, as the average cost was an estimated $69.80/bbl. But for imported crude, the average cost was up almost 15% from a year earlier, averaging about $67.50/bbl last year.

Refining margins were mixed last year compared to those of 2006. In the US, cash margins for refiners in the Midwest, nearest to most ethanol plants, were especially strong, up 27% to average $19.30/bbl for all of last year, according to Muse, Stancil & Co. The May 2007 average was the year's peak at $34.25/bbl, more that twice the average of May 2006.

Cash margins grew at more modest paces during 2007 for East Coast refiners, up 11%, and for Gulf Coast refiners, up 4% from the prior year. US West Coast refiners posted a 10% lower average margin last year.

Oil imports

The US will import reduced volumes of crude and products this year. OGJ forecasts that after last year's 1.5% decline in total gross imports, crude imports will decline 0.5% to 9.95 million b/d this year. Product imports will

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SUPPLY AND DEMAND FOR CRUDE IN THE US

	[1]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
					1,000 b/d					
SUPPLY										
Crude imports[2]	10,003	10,118	10,126	10,088	9,665	9,140	9,328	9,071	8,731	8,706
Crude production	5,114	5,102	5,178	5,419	5,681	5,746	5,801	5,822	5,881	6,252
Unaccounted for crude	247	25	76	143	54	110	117	155	191	115
Total supply	**15,364**	**15,245**	**15,380**	**15,650**	**15,400**	**14,996**	**15,246**	**15,048**	**14,803**	**15,073**
DEMAND										
Crude refinery runs	15,382	15,242	15,220	15,475	15,304	14,947	15,128	15,067	14,804	14,889
Crude used directly and loss	—	—	—	—	—	—	—	—	—	—
Crude exports	29	25	32	27	12	9	20	50	118	110
Crude into SPR	19	11	25	102	108	134	26	–73	–11	22
Total demand	**15,430**	**15,278**	**15,277**	**15,604**	**15,424**	**15,090**	**15,174**	**15,044**	**14,911**	**15,021**
Crude stock change (industry)	–66	–33	103	46	–24	–94	72	4	–108	52
Primary (industry)	288	312	324	286	269	278	312	286	284	324
SPR[3]	696	689	685	676	638	599	550	541	567	571
Total crude stocks (million bbl)	**984**	**1,001**	**1,009**	**962**	**907**	**877**	**862**	**827**	**851**	**895**

[1]Preliminary. [2]Includes imports for the Strategic Petroleum Reserve. [3]Includes Alaskan crude in transit.
Source: US Energy Information Administration

US ENERGY CONSUMPTION AND EFFICIENCY

Year	GDP, billion 2000 $	Energy consumption, trillion btu	Energy consumption per GDP, 2000 $ (Mbtu)	Oil energy consumption, trillion btu	Oil energy consumption per GDP, 2000 $ (Mbtu)	Natural gas energy consumption, trillion btu	Natural gas energy consumption per GDP, 2000 $ (Mbtu)	Total oil and natural gas energy consumption, trillion btu	Total oil and gas energy consumption per GDP, 2000 $ (Mbtu)	Oil and natural gas energy % of total energy
1973	4,341.5	75,808	17.5	34,840	8.0	22,512	5.2	57,352	13.2	75.7
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	78,289	15.2	34,202	6.6	20,394	4.0	54,596	10.6	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	76,417	12.6	30,922	5.1	17,834	2.9	48,756	8.1	63.8
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	84,605	11.9	33,553	4.7	19,730	2.8	53,283	7.5	63.0
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	91,200	11.4	34,553	4.3	22,784	2.8	57,337	7.1	62.9
1996	8,328.9	92,446	11.1	35,757	4.3	23,197	2.8	58,954	7.1	63.8
1997	8,703.5	94,800	10.9	36,266	4.2	23,328	2.7	59,594	6.8	62.9
1998	9,066.9	95,200	10.5	36,934	4.1	22,936	2.5	59,870	6.6	62.9
1999	9,470.3	96,837	10.2	37,960	4.0	23,010	2.4	60,970	6.4	63.0
2000	9,817.0	98,976	10.1	38,404	3.9	23,916	2.4	62,320	6.3	63.0
2001	9,890.7	96,453	9.8	38,333	3.9	22,861	2.3	61,194	6.2	63.4
2002	10,048.8	97,967	9.7	38,401	3.8	23,628	2.4	62,029	6.2	63.3
2003	10,301.0	98,273	9.5	39,047	3.8	22,967	2.2	62,014	6.0	63.1
2004	10,703.5	100,415	9.4	40,594	3.8	23,036	2.2	63,630	5.9	63.4
2005	11,048.6	100,358	9.1	40,735	3.7	22,636	2.0	63,371	5.7	63.1
2006	11,319.4	99,813	8.8	39,958	3.5	22,190	2.0	62,148	5.5	62.3
[1]2007	11,570.0	100,580	8.7	40,000	3.5	22,520	1.9	62,520	5.4	62.2
[2]2008	11,775.0	100,560	8.5	39,840	3.4	22,745	1.9	62,585	5.3	62.2

[1]Estimated. [2]Forecast.
Source: US Energy Information Administration

fall 1.3%, averaging 3.45 million b/d.

Strong demand for oil products drove imports higher on the US West Coast last year, as EIA figures for imports into Petroleum Administration for Defense District 5 show.

While total US demand for oil products last year declined 0.6%, demand in PADD 5 for all petroleum products climbed 1.5%. Distillate and residual fuel oil were especially strong in comparison to demand in the other four

Crude imports by country of origin[1]

	[2]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
	1,000 b/d									
Algeria[3]	501	362	228	215	112	30	11	1	25	10
Angola	535	513	456	306	363	321	321	295	357	465
Australia	1	5	10	21	27	51	34	49	31	31
Canada	1,864	1,802	1,633	1,616	1,549	1,445	1,356	1,348	1,178	1,266
China	8	19	24	14	13	20	13	33	13	42
Colombia	137	141	156	142	166	235	260	318	452	349
Congo, Republic of	0	0	0	14	2	23	1	8	2	17
Congo	68	27	25	8	27	3	40	42	46	53
Ecuador	206	272	276	232	139	100	113	125	114	98
Gabon	56	60	127	142	131	143	140	143	168	207
Indonesia[3]	19	16	19	34	26	50	40	36	70	50
Iran[3]	0	0	0	0	0	0	0	0	0	0
Iraq[3]	514	553	527	655	481	459	795	620	725	336
Kuwait[3]	172	179	227	241	208	216	237	263	246	300
Malaysia	1	7	10	18	21	9	15	29	21	26
Mexico	1,380	1,577	1,556	1,598	1,569	1,500	1,394	1,313	1,254	1,321
Nigeria[3]	1,049	1,037	1,077	1,078	832	589	842	875	623	689
Norway	48	98	119	143	181	348	281	302	263	221
Oman	50	35	22	10	35	17	20	2	0	0
Qatar[3]	0	1	0	4	0	9	0	0	1	1
Saudi Arabia[3]	1,413	1,423	1,445	1,495	1,726	1,519	1,611	1,523	1,387	1,404
Trinidad & Tobago	44	67	64	49	67	68	51	56	40	53
United Arab Emirates[3]	4	5	9	5	10	10	21	3	0	3
United Kingdom	85	130	224	238	359	405	244	291	284	161
Venezuela[3]	1,114	1,142	1,241	1,297	1,183	1,201	1,291	1,223	1,150	1,377
Others	734	717	651	513	438	369	197	173	281	226
Total imports	**10,003**	**10,188**	**10,126**	**10,088**	**9,665**	**9,140**	**9,328**	**9,071**	**8,731**	**8,706**
Total from OPEC	**4,786**	**4,783**	**4,757**	**5,042**	**4,578**	**4,083**	**4,848**	**4,544**	**4,228**	**4,169**

[1]Includes imports for the Strategic Petroleum Reserve. [2]Preliminary. [3]OPEC member.
Source: US Energy Information Administration.

Exports of refined products and crude

	*2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
	1,000 b/d									
Gasoline	106	142	136	124	125	124	133	144	111	125
Distillate	238	215	138	110	107	112	119	173	162	124
Residual	322	283	251	205	197	177	191	139	129	138
Lubricants	67	55	40	41	37	33	26	26	28	25
Coke	359	366	347	350	361	337	336	319	242	267
Asphalt and road oil	16	15	11	6	10	6	5	6	5	7
LPG	49	56	53	43	56	67	44	74	50	42
Other refined products	170	160	158	142	122	119	97	109	95	107
Total refined products	1,327	1,292	1,134	1021	1,015	975	951	990	822	835
Crude	29	25	32	27	12	9	20	50	118	110
Total exports	**1,356**	**1,317**	**1,165**	**1,048**	**1,027**	**984**	**971**	**1,040**	**940**	**945**

* Preliminary.
Source: US Energy Information Administration

PAD districts.

Canada was the US source not only of the most imported crude during 2007 but also of the highest volume of product imports for the year.

Oil demand

Demand for oil products for the entire US this year will decline to an average 20.61 million b/d in 2008 from 20.7 million b/d a year ago. In 2006, US demand for petroleum products averaged 20.688 million b/d.

Weak economic conditions coupled with relatively strong fuel prices will encourage conservation. Motorists will use less gasoline, and airlines have been flying fewer but fuller flights.

Demand for all products except distillate will fall from last year's levels.

Distillate

The increase in distillate consumption will reflect strength of the diesel market. Consumption of home heating oil, the other main distillate product, will be suppressed by above-normal temperatures predicted by the National Weather Service for most of the US.

Diesel's strength will raise average demand for all distillate to 4.3 million b/d this year from 4.25 million b/d last year and 4.169 million b/d in 2006.

Much of diesel's consumption growth reflects increasing production of ethanol for blending with gasoline. Ethanol and its main feedstock, corn, move to processing and blending facilities by rail or truck.

Production of fuel ethanol climbed to an average 452,000 b/d in October 2007, the latest month for which such data is available from EIA. This brought the 2007 year-to-date average

IMPORTS OF REFINED PRODUCTS

	[1]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
	1,000 b/d									
Gasoline	447	475	603	496	518	498	454	427	382	311
Kerosine	2	5	7	2	6	5	5	2	1	1
Jet fuel-kerosine	227	186	190	127	109	107	148	162	128	124
Distillate	304	365	329	325	333	267	344	295	250	210
Residual	458	350	530	426	327	249	295	352	237	275
Unfinished oils	722	689	582	490	335	410	378	274	317	302
Other[2]	1,336	1,519	1,346	1,191	971	854	920	877	806	779
Total US	**3,495**	**3,589**	**3,587**	**3,057**	**2,599**	**2,390**	**2,543**	**2,389**	**2,121**	**2,002**

[1]Preliminary. [2]Includes plant condensate.
Source: US Energy Information Administration

ROTARY RIG ACTIVITY BY STATES

	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Alabama	4.6	4.6	3.6	2.5	2.4	3.0	5.3	4.1	5.5	6.0
Alaska	8.4	8.0	9.3	9.9	9.7	11.2	13.4	8.2	5.0	12.0
Arizona	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0
Arkansas	45.4	24.0	9.3	6.4	2.1	0.8	1.5	3.9	2.5	6.2
California	35.4	33.3	27.2	23.9	21.1	22.3	36.4	24.1	19.0	27.9
Land	33.8	29.3	23.0	20.4	17.9	19.7	32.5	20.7	17.4	26.1
Offshore	1.6	4.0	4.2	3.5	3.2	2.6	3.9	3.4	1.6	1.8
Colorado	106.7	88.5	73.9	54.2	38.8	27.8	32.3	18.4	12.5	12.8
Florida	0.4	0.3	1.6	1.1	0.7	0.2	0.4	0.2	0.2	0.1
Idaho	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indiana	2.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0
Kansas	13.8	9.6	6.7	6.7	8.7	7.5	22.4	22.0	7.4	13.2
Kentucky	9.0	7.2	4.7	4.4	4.3	4.8	6.4	4.9	5.5	2.4
Louisiana	177.0	188.4	182.1	166.8	157.2	162.8	213.8	194.4	141.1	187.4
North	57.9	57.5	48.4	39.3	28.5	23.2	30.3	24.1	16.2	18.9
Inland waters	24.6	19.2	22.8	18.2	14.3	16.3	20.4	15.8	15.5	21.4
South	33.8	38.5	32.5	30.3	29.6	31.6	44.1	36.7	21.1	40.8
Offshore	60.7	73.2	78.4	79.1	84.8	91.7	119.0	117.9	88.3	106.4
Michigan	1.5	2.2	2.6	3.0	3.1	1.3	1.2	2.4	2.1	5.4
Mississippi	14.0	10.3	10.3	9.8	8.0	7.6	14.2	11.2	7.4	14.0
Montana	16.9	21.3	24.0	19.9	14.0	7.9	10.0	6.5	4.3	8.6
Nebraska	0.1	0.0	0.0	0.8	0.0	0.1	0.2	0.6	0.3	0.5
Nevada	2.2	1.3	1.9	1.5	1.2	0.0	0.0	0.0	0.0	0.0
New Mexico	78.1	93.8	82.8	67.2	64.4	41.5	68.2	67.9	36.0	44.7
New York	6.4	6.4	4.3	4.9	2.8	4.3	5.4	3.3	2.5	2.2
North Dakota	38.9	31.5	20.4	15.0	13.7	10.1	14.3	13.4	5.9	11.2
Ohio	13.2	7.5	9.2	6.7	7.4	8.7	9.6	8.5	10.5	10.1
Oklahoma	188.2	178.7	152.1	158.8	128.2	90.8	130.2	99.4	61.9	84.9
Pennsylvania	15.6	15.7	13.2	8.9	10.1	10.3	10.6	8.7	7.8	10.9
South Dakota	1.5	1.1	2.0	0.5	0.2	0.2	0.6	0.2	0.5	0.1
Texas	834.3	746.4	614.7	505.9	448.5	337.5	462.5	343.4	227.1	302.3
Gulf Coast	180.3	170.3	184.6	156.1	153.0	134.3	168.1	127.1	50.0	63.4
Offshore & inland waters	10.5	14.8	10.5	14.1	20.2	16.2	26.4	16.6	13.8	11.5
North	36.7	33.5	31.8	37.4	39.4	30.1	27.4	14.5	10.5	10.5
Panhandle	60.5	68.2	62.5	47.5	26.0	14.6	21.0	16.7	13.7	20.8
East	294.8	243.3	172.5	131.2	107.2	68.1	106.1	78.0	38.9	54.7
West Central	94.6	79.0	53.0	45.3	28.4	21.9	31.7	17.4	50.1	72.9
West	156.9	137.5	100.0	74.2	74.2	52.5	81.6	73.1	50.1	68.5
Utah	41.1	40.2	27.7	21.5	13.4	13.1	20.8	15.5	8.8	12.5
West Virginia	31.6	26.5	17.4	15.1	15.5	13.2	18.1	14.1	13.7	14.3
Wyoming	73.6	99.0	78.5	73.6	53.6	40.2	55.0	41.0	31.8	38.6
Others	7.6	2.6	3.6	1.5	1.2	2.2	3.6	2.0	5.7	2.6
Total US	**1,767.8**	**1,648.7**	**1,383.1**	**1,190.5**	**1030.3**	**830.2**	**1,156.4**	**918.3**	**624.9**	**830.6**
Land	1,669.8	1,536.6	1,265.9	1,074.0	905.6	699.9	981.4	761.2	502.0	684.7
Inland waters	25.7	22.2	23.7	19.4	16.8	17.7	21.9	17.3	16.6	22.1
Offshore	72.6	89.9	93.4	97.0	107.9	112.6	153.1	139.8	106.3	123.9
Canada—land	340.0	466.5	454.3	361.1	369.8	259.5	336.3	339.7	240.1	255.9
Canada—offshore	2.5	3.6	3.8	3.9	3.8	6.1	5.2	4.7	5.2	3.6
Grand total	**2,110.3**	**2,118.8**	**1,841.2**	**1,555.5**	**1403.9**	**1,095.8**	**1,497.9**	**1,262.7**	**870.1**	**1,090.2**

Source: Baker Hughes Inc. Note: May not add due to independent rounding.

to 411,000 b/d.

In December Congress passed an energy bill that raises the renewable fuel standard to 36 billion gal by 2022, more than half of which must come from sources other than corn (OGJ, Dec. 24, 2007, p. 30). The current standard, set in 2005, peaks at 7.5 billion gal/year in 2012.

The new measure will further boost consumption of distillate because of ethanol's transport requirements. More

Marketed natural gas production[1]

	[2]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
	MMcfd									
Alaska	1,199	1,218	1,335	1,289	1,305	1,269	1,292	1,254	1,268	1,278
Louisiana	3,584	3,729	3,551	3,697	3,760	3,731	4,115	3,975	4,293	14,487
New Mexico	4,087	4,409	4,507	4,460	4,234	4,471	4,628	4,645	4,142	4,113
Oklahoma	4,857	4,627	4,491	4,524	4,572	4,250	4,426	4,419	4,367	4,506
Texas	16,229	15,106	14,456	13,845	14,460	14,085	14,473	14,432	13,848	17,312
Wyoming	4,886	4,976	4,491	4,350	4,125	3,983	3,737	2,974	2,661	2,086
Federal offshore	7,426	7,951	8,581	10,845	12,263	12,804	13,774	13,482	13,780	–
Others	11,157	11,085	10,442	10,314	10,159	9,984	9,912	10,004	9,901	10,042
Total	**53,425**	**53,101**	**51,855**	**53,326**	**54,877**	**54,578**	**56,357**	**55,184**	**54,260**	**53,823**
Volume change	324	1,246	-1,471	-1,550	299	-1,779	1,173	925	436	-604
Percent change	0.6	2.4	-2.8	-3	1	-3	2	2	1	-1
Imports	12,137	11,469	11,893	11,635	10,164	10,979	10,896	10,332	9,823	8,636
Exports	2,055	1,983	1,996	2,334	1,644	1,414	1,023	666	448	436

[1]Includes nonhydrocarbon gases. [2]Preliminary. [3]Starting in 1999, federal Gulf of Mexico production is broken out, 1998 included with the state total.
Source: US Energy Information Administration

Refinery runs by districts

	2007			Crude runs								
	Crude runs[1]	Input to crude stills[1]	% of operable capacity	2006	2005	2004	2003	2002	2001	2000	1999	1998
	1,000 b/d			1,000 b/d								
East Coast	1,424	1,376	82.7	1,418	1,534	1,508	1,516	1,455	1,413	1,485	1,456	1,480
Appalachian Dist. 1	90	89	89.1	94	93	89	88	85	86	86	92	89
Total Dist. 1	**1,515**	**1,465**	**83.1**	**1,512**	**1,627**	**1,597**	**1,605**	**1,541**	**1,499**	**1,571**	**1,548**	**1,569**
Ill., Ind., Ky.[2]	2,195	2,191	90.8	2,161	2,143	2,157	2,107	2,108	2,165	2,239	2,232	2,263
Minn., Wisc., Daks.	417	410	90.5	413	420	403	395	701	414	422	392	424
Okla., Kan., Mo.	690	690	85.2	723	735	729	710	701	724	712	706	684
Total Dist. 2	**3,302**	**3,291**	**89.6**	**3,297**	**3,298**	**3,288**	**3,212**	**3,511**	**3,303**	**3,373**	**3,330**	**3,371**
Texas:												
Inland	548	571	83.2	610	579	604	572	554	574	573	557	582
Gulf Coast	3,427	3,439	85.1	3,445	3,489	3,682	3,652	3,475	3,549	3,455	3,383	3,490
Louisiana Gulf	3,158	3,181	104.0	2,913	2,751	2,906	2,872	2,848	2,922	2,843	2,793	2,608
N. La., Ark.	191	182	87.4	197	186	151	156	148	154	178	188	184
New Mexico	106	105	84.9	95	95	94	81	84	79	90	90	92
Total Dist. 3	**7,430**	**7,479**	**92.1**	**7,260**	**7,098**	**7,438**	**7,332**	**7,109**	**7,278**	**7,139**	**7,012**	**6,957**
Total Dist. 4	**557**	**555**	**90.6**	**553**	**558**	**556**	**528**	**520**	**500**	**505**	**498**	**480**
Total Dist. 5	**2,579**	**2,794**	**85.6**	**2,621**	**2,638**	**2,596**	**2,627**	**2,567**	**2,547**	**2,479**	**2,416**	**2,512**
Total US	**15,382**	**15,584**	**89.4**	**15,242**	**15,220**	**15,475**	**15,304**	**15,247**	**15,128**	**15,067**	**14,804**	**14,889**

[1]Preliminary. [2]Includes Appalachian Dist. 2
Source: US Energy Information Administration

than two thirds of current distillate demand is ultralow-sulfur diesel required for on-highway use.

Motor gasoline

Following 15 years of growth, demand for motor gasoline will decline this year. Higher prices are changing driving habits.

Average gasoline demand will be 9.27 million b/d, compared with 9.3 million b/d last year and 9.25 million b/d in 2006.

Regular unleaded pump prices in 2007 increased 7% from a year earlier, according to BLS figures. In 2006, the pump price for regular unleaded fuel rose 13% from a year earlier.

Following springtime maintenance, inventories of gasoline will be pinched. Gasoline prices will rise at the start of this year's driving season as summer blends return to the market.

Jet fuel

Demand for jet fuel this year will be nearly unchanged at 1.62 million b/d. Airlines have improved efficiencies over the past few years such that in 2007 jet fuel consumption dipped 0.7% from 1.633 million b/d a year earlier.

Retail prices for jet fuel were slightly lower or unchanged for the first 8 months of last year, but in September and October jet fuel prices climbed 13% and 30% respectively from year-earlier levels. Inventories were adequate; the price hike was due to rising crude costs.

Residual fuel oil

Resid demand will fall almost 3%

US REFINED PRODUCTS, NATURAL GAS LIQUIDS, AND CRUDE STOCKS

	[1]2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
	1,000 bbl									
Gasoline[2]	202,942	174,072	209,735	219,081	208,167	210,609	211,465	197,429	195,142	217,696
Motor[3]	201,825	172,935	208,328	217,601	206,827	209,096	209,851	195,852	193,327	215,639
Aviation[3]	1,117	1,137	1,407	1,480	1,340	1,513	1,614	1,577	1,815	2,057
Special naphthas	1,449	1,473	1,524	1,800	2,006	2,038	2,006	2,112	2,351	2,207
Kerosene	2,182	3,125	5,092	4,885	5,584	5,463	5,388	4,107	4,871	6,943
Distillate	128,031	131,690	136,022	126,272	136,542	134,085	144,513	118,027	125,463	156,075
Residual	37,398	41,081	37,387	42,363	37,800	31,333	41,047	36,200	35,830	44,909
Kerosine jet fuel	40,922	40,072	41,741	40,086	38,767	39,123	41,871	44,409	40,447	44,660
Naphtha jet fuel	—	—	—	—	17	56	82	109	54	34
Natural gas liquids & LRG	113,581	120,121	118,206	111,085	100,889	113,285	128,272	87,722	94,721	123,760
Unfinished oils	90,363	88,041	85,723	81,380	75,904	75,766	87,700	84,217	86,254	90,836
Other refined products	69,131	95,325	53,926	56,512	55,364	59,447	61,784	67,030	56,075	64,907
Total products stocks	686,000	719,000	689,356	683,464	661,040	671,205	724,128	641,362	641,208	752,027
Crude stocks (ex. SPR)	288,000	312,000	323,704	285,741	268,875	277,614	311,980	285,507	284,482	323,543
Total stocks (ex. SPR)	**974,000**	**1,031,000**	**1,013,060**	**969,205**	**929,915**	**948,819**	**1,036,108**	**926,869**	**925,690**	**1,075,570**
SPR stocks	**696,000**	**689,000**	**684,544**	**675,600**	**638,388**	**599,091**	**550,241**	**540,678**	**567,241**	**571,405**
Total stocks (incl. SPR)	**1,670,000**	**1,720,000**	**1,697,604**	**1,644,805**	**1,568,303**	**1,547,910**	**1,586,349**	**1,467,547**	**1,492,931**	**1,646,975**

[1]Preliminary. [2]Includes reformulated, oxygenated, and other finished gasoline. [3]Includes blending components.
Source: US Energy Information Administration.

to 720,000 b/d after last year's price-driven 7.5% increase.

High natural gas prices during 2007 gave resid consumption a boost. Although switching capacity between gas and resid for electric generation is on the decline, there is still enough to make an impact.

Resid prices over the past 2 years were strong, too. Through the first 9 months of 2007, the average end-user price of resid was $1.28/gal, up from $1.26/gal a year earlier and an average of 99¢/gal in the first 9 months of 2005.

LPG, other products

Demand for liquefied petroleum gases will decline to 2.05 million b/d, about the same as demand for these products in 2006.

Last year LPG consumption averaged 2.06 million b/d as US demand for propane and propylene climbed. Exports of propane and propylene last year declined about 15%, but production of these products at refineries increased.

Average demand for all other petroleum products this year will decline to 2.65 million b/d from 2.72 million b/d last year and 2.89 million b/d in 2006.

This group of products includes pentanes-plus, unfinished oils, gasoline blending components, and other hydrocarbons and oxygenates. Demand for these products used in construction will be hurt by this year's economic sluggishness.

Natural gas

Growth in electric power generation will drive US demand for natural gas this year.

Gas demand will total 22.195 tcf, up 1.5%. Last year, gas demand climbed 3%.

Marketed production of gas in the US will grow to 19.7 tcf up from 19.5 tcf last year. Production in Texas, Louisiana, and the federal Gulf of Mexico will post increases. Last year, production declined in Louisiana and in federal waters of the gulf.

Major upstream projects coming on stream in 2007 and 2008 will boost production this year. These big gas producers include Independence Hub, Atlantis, Phoenix, Thunder Hawk, and Thunder Horse.

Total gross imports will be unchanged this year at 4.43 tcf. Last year, a surge in LNG imports resulted in a nearly 6% increase in gas imports, but LNG imports this year will grow more modestly.

OGJ forecasts that LNG imports will be 800 bcf this year. Imports from Mexico will remain at 50 bcf, and imports from Canada will decline to 3.58 tcf from 3.6 tcf last year.

The source of the largest volume of last year's LNG imports was by far Trinidad and Tobago. Egypt, Nigeria, and Algeria were also major sources for last year's imports.

US gas exports will climb almost 7% this year. Last year, exports rose to 750 bcf from 724 bcf a year earlier, as pipeline exports to Canada increased but exports to Mexico declined a little.

Residential demand and demand for natural gas by electric power producers drove last year's increase in consumption. Deliveries of gas to commercial and industrial users last year grew, as well. Production and imports were up, and inventories were plentiful throughout 2007.

The amount of working gas in storage has weakened prices. Since early 2006, inventories have been at or near the top of the 5-year range of working gas in storage.

Since then, gas prices have dropped. Gas futures prices on the New York Mercantile Exchange peaked in December 2005 with a closing price as high as $15.378/MMbtu.

Inventories closed 2007 near the middle of the 5-year range at about 2.75 tcf. This was down 9% from yearend 2006.

During 2007, prices were largely range-bound, with the lowest futures closing price occurring on Aug. 27, 2007, at $5.38/MMbtu. The peak closing price for the year registered on Nov. 1, 2007, at $8.637/MMbtu. ✦

Smaller drilling gain due in US as Canada's drop persists

Alan Petzet
Chief Editor-Exploration

Oil and gas drilling in the US will depend as much as ever on commodity price levels.

All indicators point to another drilling decline in Canada, but for now OGJ still forecasts a small uptick in drilling in the US.

Most operators project higher capital and exploration budgets for 2008, and those in the large multirig and mostly unconventional gas plays still foresee increasing the number of rigs they employ throughout the year.

Nevertheless, lingering price weakness could temper the optimism or even result in underspending if not outright cutting of budgets.

Here are highlights of OGJ's early year drilling forecast for 2008.

- Operators will drill 49,012 wells in the US, up from an estimated 47,057 wells drilled in 2007.
- All operators will drill 4,001 exploratory wells of all types, up from an estimated 3,833 last year.
- The Baker Hughes Inc. count of active US rotary rigs will average 1,850 rigs/week this year, up from 1,768 in 2007 and 1,649 in 2006.
- Operators will drill 15,560 wells in western Canada, down from an estimated 18,391 wells in 2007.

Activity by state

As this forecast was being prepared in early January, the Baker Hughes rig count had fallen four straight weeks, ending at 1,774 after the week ended Jan. 4.

However, this was still 79 rigs higher than the count at the dawn of 2007.

OGJ looks for operators to drill

15,220 wells in Texas compared with an estimated 14,511 in 2007.

Wyoming seems to be the only state where a decrease seems certain this early in the year. Wyoming will host an estimated 3,255 wells drilled, which would be a 5.6% drop from OGJ's 2007 estimate. The state's oil and gas conservation commission said indicators there point to a drop in the number of coalbed methane wells and other gas wells drilled this year.

Oklahoma will see 3,808 wells drilled, up from 3,625 last year, and the estimate for Colorado is 3,625 wells compared with 3,445 in 2007.

Louisiana at OGJ's estimate of 2,275 wells would be nearly unchanged from 2007.

US plays

Plays in the northern Rockies and even farther south may entice contractors to transport rigs that have lost work in Canada, and newbuild rigs will also contribute to the available US land rig fleet.

The Barnett shale play in Texas has sprawled from its core in Denton, Wise, and Tarrant counties to the noncore counties of Bosque, Clay, Comanche, Cooke, Ellis, Erath, Hamilton, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, and Somervell, the Texas Railroad Commission noted. One company, Chesapeake Energy Corp., said it is running 38-40 operated rigs in the Barnett play (OGJ Online, Jan. 9, 2008).

East Texas, defined as the area from Tarrant and Robertson counties to the

A LOOK AT 30 YEARS OF US WELL COMPLETIONS

Year	Total wells[1]	Total footage	Total explor–atory wells	Year	Total wells[1]	Total footage	Total explor–atory wells
[2]2008	49,012	302,906,000	4,001	1993	26,032	138,509,000	3,604
[2]2007	47,057	279,001,000	3,833	1992	23,921	123,456,000	3,494
2006	49,375	289,959,000	3,696	1991	28,417	141,391,000	4,399
2005	44,679	254,844,000	3,727	1990	30,615	149,518,000	5,074
2004	39,051	213,908,000	3,192	1989	28,363	134,901,000	5,251
2003	30,487	158,221,000	2,593	1988	32,238	155,164,000	6,350
2002	27,794	145,055,000	2,271	1987	36,253	163,848,000	6,903
2001	36,061	184,462,000	3,181	1986	39,015	177,641,000	7,156
2000	31,261	149,848,000	2,517	1985	70,806	316,778,000	12,208
1999	22,107	109,854,000	2,141	1984	84,983	368,796,000	15,138
1998	25,822	143,625,000	2,723	1983	75,738	316,617,464	13,845
1997	30,208	165,480,000	3,353	1982	83,889	375,382,919	15,882
1996	25,724	138,588,000	3,364	1981	89,234	406,520,453	17,430
1995	23,061	124,426,000	3,406	1980	69,486	311,444,837	12,870
1994	23,324	130,654,000	3,788	1979	51,890	243,685,430	10,735

[1]Well counts in most recent years subject to reporting lag. [2]Estimated.
Source: 1975-2006 American Petroleum Institute

OIL & GAS JOURNAL WELL FORECAST FOR 2008

State	2007 estimate Total comp.	2007 estimate Explor–atory wells	2007 estimate Field wells	2007 estimate Total ft (1,000)	2008 forecast Total comp.	2008 forecast Explor–atory wells	2008 forecast Field wells
Alabama	445	20	425	1,663	471	22	449
Alaska	165	5	160	1,083	170	5	165
Arizona	3	3	0	10	5	1	4
Arkansas	745	37	708	4,729	800	39	761
California land	2,600	68	2,532	6,271	2,715	71	2,644
California offshore	6	0	6	36	8	0	8
Colorado	3,445	165	3,280	19,761	3,625	174	3,451
Florida	1	1	0	13	1	1	0
Illinois	365	40	325	852	383	42	341
Indiana	120	10	110	175	130	11	119
Kansas	2,420	196	2,224	8,170	2,550	207	2,343
Kentucky	910	34	876	2,641	950	35	915
Louisiana	2,270	207	2,063	21,540	2,275	206	2,069
North	1,140	104	1,036	9,863	1,200	109	1,091
South	545	26	519	5,447	525	25	500
Offshore	585	77	508	6,230	550	72	478
Michigan	470	102	368	840	505	109	396
Mississippi	275	29	246	2,583	288	31	257
Montana	795	125	670	4,693	759	119	640
Nebraska	50	15	35	191	57	17	40
Nevada	3	2	1	15	5	4	1
New Mexico—East	1,090	68	1,022	8,331	1,145	71	1,074
New Mexico—West	885	10	875	4,283	935	10	925
New York	110	3	107	363	115	3	112
North Dakota	485	93	392	5,364	525	100	425
Ohio	1,095	128	967	4,506	1,170	137	1,033
Oklahoma	3,625	134	3,491	26,270	3,808	141	3,667
Oregon	0	0	0	0	3	3	0
Pennsylvania	2,975	292	2,683	10,053	3,150	309	2,841
South Dakota	14	2	12	52	14	2	12
Tennessee	175	17	158	388	188	18	170
Texas	14,511	1,302	13,209	119,968	15,220	1,354	13,866
Dist. 1	550	47	503	3,499	595	51	544
Dist. 2	725	109	616	6,679	775	116	659
Dist. 3	887	111	776	7,557	925	116	809
Dist. 4	1,365	120	1,245	13,262	1,455	128	1,327
Dist. 5	1,514	55	1,459	16,434	1,605	58	1,547
Dist. 6	1,660	183	1,477	17,141	1,740	191	1,549
Dist. 7-B	1,275	48	1,227	7,920	1,340	51	1,289
Dist. 7-C	1,451	77	1,374	10,820	1,525	81	1,444
Dist. 8	1,843	123	1,720	12,343	1,950	131	1,819
Dist. 8-A	965	99	866	5,246	935	96	839
Dist. 9	1,127	28	1,099	7,021	1,200	30	1,170
Dist. 10	1,029	249	780	10,819	1,070	259	811
Offshore	120	53	67	1,226	105	46	59
Utah	1,119	246	873	8,838	1,185	261	924
Virginia	475	76	399	1,257	525	83	442
Washington	1	1	0	13	2	2	0
West Virginia	1,959	298	1,661	8,565	2,075	315	1,760
Wyoming	3,450	104	3,346	17,440	3,255	98	3,157
US total	**47,057**	**3,833**	**43,224**	**290,958**	**49,012**	**4,001**	**45,011**
Western Canada	18,391	4,259	14,132	426	15,560	3,600	11,960
Alberta	14,036	3,228	10,808	323	10,650	2,450	8,200
Saskatchewan	3,214	643	2,571	64	3,350	670	2,680
British Columbia	846	338	508	34	935	374	561
Manitoba	295	50	245	5	625	106	519
NWT—Yukon	10	8	2	1	12	10	2
Atlantic offshore	6	2	4	0	6	2	4
Other E. Canada	128	10	118	1	135	11	124

Oklahoma and Louisiana state lines, was responsible for 35% of the average Texas rig count in 2007. The area includes the eastern part of the Barnett shale play and other mainly gas plays in numerous Cretaceous and Jurassic formations.

The top two Arkansas Fayetteville shale players, Southwestern Energy Co. and Chesapeake Energy Corp., said they were operating 19 and 11 rigs, respectively, at the end of 2007. Southwestern alone planned to participate in 475 wells in the play in 2008.

Petrohawk Energy Corp., Houston, will shortly hike its Fayetteville play position to 150,000 net acres with the purchase of leasehold mainly in Van Buren, Conway, and Cleburne counties from a private seller.

Newfield Exploration Co. had 13 rigs running in the Arkoma basin Woodford shale gas play in December 2007, 11 of which were drilling development wells.

Pioneer Natural Gas USA Inc. announced plans to drill 350 oil wells in the Spraberry Trend of West Texas and 175 coalbed methane wells in the Raton basin in southeastern Colorado in 2008.

Canada's outlook

OGJ's estimate for Canada is more generous than that of associations north of the border.

The Canadian Association of Oilwell Drilling Contractors and the Petroleum Services Association of Canada in late October forecast a hefty 17% drilling decline to 14,500 wells in 2008. The groups' expectations were already low before Alberta imposed a more onerous royalty regime.

Nearly 500 rigs were inactive in Canada in 2007, calculated Nickles Energy Group, greater than the number of available rigs 11 years earlier.

Nickles figures also show that 11.6% of the approved well permits in western Canada in 2007 were for oilsands evaluation wells.

Canadian operators are also limiting risk by drilling fewer exploratory wells. OGJ estimates that only 3,600 such wells will be drilled in 2008, down from an estimated 4,259 last year. ✦

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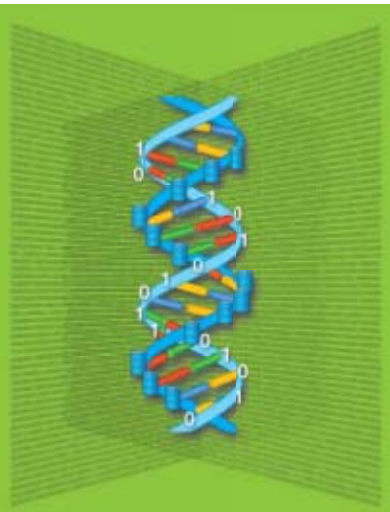

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GENERAL INTEREST

Iraq takes licensing step, but E&P fiscal policy murky

Ferruh Demirmen
Consultant
Houston

The invitation extended early this month by Iraq's Ministry of Oil to international oil companies (IOCs) to preregister by Jan. 31 for exploration and production licensing rounds has no doubt attracted much interest in the industry (OGJ Online, Jan. 3, 2008).

In its announcement, the ministry requested the applicant companies to provide a comprehensive list of information, from company bylaws to tax compliance record to HSE policy. The ministry will use the information to select those companies that will be allowed to compete for upstream projects in the country. The scope of information requested for qualification may set a new standard in the industry.

But IOCs are still mainly in the dark as to Iraq's fiscal policy. Timing of the first licensing round is also unclear.

A festering dispute

A long-festering dispute between the federal government and the autonomous Kurdistan Regional Government (KRG) in the north concerning the oil sector has kept the federal government from enacting a petroleum law for upstream projects. The federal government, dominated by Arab leaders, wants centralized control of the oil sector. In contrast, KRG wants decentralized control. There are also differences as regards the contracting terms.

KRG has passed its own (regional) petroleum law and has signed a number of E&P contracts with foreign companies—e.g., DNO, Genel Enerji/Addax—putting the central government in an awkward position.

COMMENT

Because of the dispute, a draft federal petroleum law approved by Iraq's cabinet in February 2007 went nowhere.

Last November Iraqi Oil Minister Hussain Al-Shahristani criticized foreign oil companies making deals with KRG (OGJ, Dec. 3, 2007, Newsletter). According to a Jan. 10 United Press International report, the leader of the Iraqi Parliament's Energy Committee, Abdul Hadi al-Hassani, accused Iraq's Kurdish leadership and the national ministerial council of stalling the petroleum law, repeating the national government's position that the KRG deals are illegal.

The oil ministry apparently decided to issue a prequalification invitation ahead of a final petroleum law because it felt the urgency to act in the face of developments in northern Iraq. Exploratory drilling in the KRG territory has uncovered some prolific finds, presaging early production. Export outlet remains a problem, however. KRG contractors are not allowed to use the Kirkuk pipeline heading north. Although some crude from new discoveries has found its way to Iran by tanker transport, major development and significant export must await rapprochement with the national government.

Contracting policy

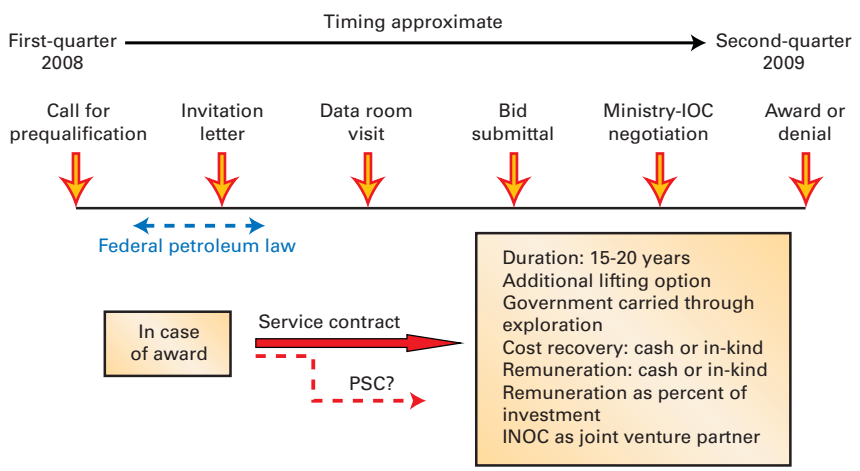
Although details of Iraq's petroleum law are uncertain, the general thinking of the national government on this subject can be gleaned from a presentation delivered in Dubai last September by N.K al-Bayati, director general of petroleum contracts and licensing, Ministry of Oil.

According to el-Bayati, the government's preference is service contracts (see figure). It is noted that IOCs would favor production sharing contracts (PSCs) but that the government, given the political and economic culture, considers PSCs unsuitable for Iraq.

Evidently, the government feels that the profit oil split embodied in the PSC model would compromise state ownership of oil and gas (notwithstanding that the net "take" values—government vs. IOC shares—under the service contract and PSC could be similar). The service contract model was used in a limited fashion in Iraq after nationalization in 1972.

A 15-20 year service contract with the option for additional lifting is foreseen, with cost recovery and remuneration in cash ("basically") or in-kind. Remuneration would likely

IRAQ'S CURRENTLY ENVISAGED LICENSE SCHEME



be a percentage of the investment. The contractor would bear the risk and carry the government through exploration, if applicable.

Iraq National Oil Co. (INOC) would have the right to form joint ventures (up to 50% interest) with contractors in development and production projects. Whether INOC would fully share the related costs, or would be partially carried by the contractor, is not clear.

No mention is made of any bid fee, of possible consequences of cost overrun, of delay or underperformance in production, cost recovery limit, payout, allowed rate of return, etc. The duration of the contract is generous compared to the Iranian buyback scheme.

The service contract approach stands in contrast with the PSC approach adopted by KRG.

All licensing rounds, whether at the federal or regional level, would be referred to a Federal Oil and Gas Council (FOGC) that would have the authority to review and approve contracts. FOGC would also set priorities on exploration blocks and fields to be tendered. Regional authorities would make proposals to the federal government and hold licensing rounds in their territories using model contracts drawn up by FOGC. (Currently the KRG territory is the only "region" in the federal structure).

INOC would play a key role in dealings with the IOCs and carry out upstream activities on its own.

Somewhat unusually, two separate committees, one for exploration blocks and the other for fields, would handle bid evaluation and negotiation.

Long-awaited round

Preceded by a preregistration invitation, a long-awaited E&P licensing round by Iraq's oil ministry thus may be in the offing. But in the absence of a federal petroleum law, contractual terms remain sketchy. IOCs will gauge their interest in Iraqi licensing according to the fiscal terms offered. A federal petroleum law, embodying the service contract as the dominant if not the sole model, will likely be enacted within the next few months.

Indications are that the initial licensing round will include few exploration blocks and fields to test the efficiency of the new system and assess investor response.

How the legal status of KRG's contracts will be handled in the federal law remains to be seen. It is expected that the federal law will acquiesce to these contracts but ban similar contracts in the future. IOCs deemed "errant" may be excluded from future licensing rounds.

Overriding all these developments is the certainty that no real progress in Iraq's licensing rounds can be expected until the security situation improves. ✦

The author
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Westwood: Big oil needs new business model

Sam Fletcher
Senior Writer

The fundamentals of population and economic growths are driving a worldwide demand for oil that has recently pushed crude prices to $100/bbl and have producers scrambling for the reserves to satisfy market needs, said John Westwood, managing director of the UK consultancy Douglas-Westwood Ltd.

"In my view, 'big oil' now needs a new business model, and nothing demonstrates that more than oil company stock buybacks—this is paramount to saying investors can find a better return for the money than oil companies can. So the key question that remains is 'where can big oil profitably reinvest?" said Westwood at a luncheon meeting of 200 oil and gas industry participants Jan. 10 in Houston.

Based on historic data, "oil production tracks world population [growth] except when oil is too cheap or too expensive," Westwood said. Weakness of the US dollar against the euro and yen is "without a doubt" one of the major factors supporting high oil prices today. Another is the declining production of oil outside the Organization of Petroleum Exporting Countries, "particularly in shallow [ocean] waters," Westwood said. With the "easy" oil now gone, the big onshore and offshore projects vital to the major integrated countries are now "in politically troubled areas," he said.

In the early 1970s, international oil companies controlled 80% of world oil reserves. But now the position has been "completely reversed" with the national oil companies holding 80% the remaining reserves. "Even in shallow waters, the oil companies now face much higher costs. For example, per barrel lifting costs in the UK sector of the North Sea in 2005 was $15, but by 2007 it had increased by 67% to $25," said Westwood.

"Virtually the only place where giant fields will be found in future years is in deepwater; Brazil's recent Tupi elephant find is testament to that," he said. Douglas-Westwood sees world deepwater production growing worldwide to 11 million b/d by 2011 from 6 million b/d in 2007. "This drive to produce what is very high-cost oil, from deep water is the oil companies' response to declining production in offshore continental shelf areas such as the North Sea and Gulf of Mexico and the increasingly onerous terms being sought by the biggest holders of on-shore oil reserves,

the NOCs," Westwood said.

"Another hard place is Arctic waters where the prospects of massive reserves (estimates range from 160-300 billion bbl of oil equivalent) have resulted in a 'great subsea land claim' being played out by Russia, Canada, and the US, against a spring 2009 deadline imposed by the United Nations Convention on Law of the Sea," he said. There are 45 countries that are trying to prove up potential claims to portions of the Arctic. "Russia may have control over 60% of the Arctic reserves, but it hasn't the technology to develop them," Westwood said. That means Russia will have to bring in Western partners with the equipment and expertise to develop Arctic reserves, as well as the huge investments to finance such programs.

"Recent $100 oil has only served to add to the already massive demand for the products and services of firms that supply the offshore oil and gas companies. Suppliers are virtually beating off the customers, but demand continues to grow," said Westwood. As a result, he said, "The offshore oil field services sector is facing unprecedented levels of business; some companies that might normally have a 6-month backlog are now booking work for 2011."

Douglas-Westwood expects capital expenditures of $25 billion to be invested annually in deepwater projects in 2008-12, a 30% growth over spending in the previous 5 years. "This will drive demand for deepwater drilling rigs, floating production systems, subsea production hardware, and more," said Westwood.

Recruiting and retaining qualified personnel remains a major challenge for all of the oil and gas industry. "The real crunch is the lack of experienced people—that's the single biggest problem year after year," Westwood said. ✦

New UK energy bill calls for simpler regime

Uchenna Izundu
International Editor

The UK's new energy bill calls for a simpler regime for offshore gas supply infrastructure so energy companies can invest with greater clarity and with reduced costs and risks, the government said on Jan. 10.

Admitting the present regime was complex and a "barrier to investment," the UK said it was determined to bolster gas supply security as it prepares to import more than half of its needs by 2020.

The bill will propel smaller players in the North Sea into offshore oil and gas decommissioning by ensuring adequate environmental and taxpayer protections, the government said.

Energy companies also will be encouraged to invest in carbon capture and storage to help address climate change, and the government will create a licensing regime for storing carbon dioxide offshore. Decommissioning costs are estimated at £15-19 billion, with 500 oil and gas installations in the UK North Sea and more than 6,000 miles of pipeline.

Oil and Gas UK, the trade association, cautiously welcomed the proposals, saying it initially appeared to "simplify and strengthen the regulatory framework to give investors more clarity and certainty in the areas of offshore gas infrastructure, licensing, and decommissioning."

The UK also has proposed a fleet of new nuclear power stations to enhance the country's energy security and reduce carbon emissions, with new plants possibly in operation by 2020.

The controversial measure, condemned by environmentalists, would be paid for entirely by energy companies. Each station, to be developed on existing or shut-down nuclear sites, is estimated to cost £1.5 billion. Companies will pay the full costs of decommissioning and their full share of waste management costs.

Welcoming nuclear power into the energy mix is a complete change of attitude, as the governing Labor party initially described going nuclear as "an unattractive option" in 2003. High oil prices, however, have made nuclear power a much more attractive option.

But as other countries continue to build nuclear fleets—with more than 30 reactors under construction, and over 90 ordered or at advanced stages of planning—the UK will need to compete to draw investment for resources, components, and capital.

Tony Ward, utilities director at Ernst & Young said, "The implementation of projects that will result in operational reactors before 2020 will depend on whether or not government policy and commercial environments remain robust. Speed, clarity, and continued confidence will be the key to success for any UK projects," he continued. "The global market is vibrant and hence there is great competition—the UK will need to work hard to remain an attractive option." ✦

Argentina cuts local energy supply, bans exports

Eric Watkins
Senior Correspondent

Argentina's President Cristina Fernandez de Kirchner has blamed global warming for current energy cuts and export controls her government is imposing following a recent heat wave.

"These major changes in temperature haven't come out of nowhere, they have a direct link to the environment" said Fernandez, whose husband, former President Nestor Kirchner, has been blamed by critics for his failure to address the problem of supply.

During his time in office, Kirchner repeatedly criticized oil and gas companies such as Repsol-YFP SA and Petroleo Brasileiro SA for not investing enough, while the companies called for the government to raise domestic prices in order to create a better climate for investment.

President Fernandez said there were more that 50,000 simultaneous power cuts on Jan. 8 after demand peaked. She said electricity supply had been disrupted to almost 6% of the grid as a result of the high temperatures, with some 1.2 million people affected—some 300,000 in Buenos Aires alone.

To reverse the situation, GE Energy in December said it would supply 20 natural gas-fueled Jenbacher generator sets for a new 30 Mw power plant being built to support the regional grid as well as oil and gas field production requirements in southwestern Argentina as the country seeks to overcome its energy shortages.

Industrial equipment provider Industrias Juan F. Secco SA of Santa Fe, Argentina, ordered 20 of GE's JGS 420 GS-N.L Jenbacher gen-sets, which will be installed at the expanded El Huemul power plant owned by Occidental Corp., and at new power plants being built.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Brazil courts Cuba

Oil diplomacy is under way in Latin America. We recently speculated that Venezuela's President Hugo Chavez was wooing the Portuguese to spite the Brazilians. Now, the Brazilians are turning the tables.

What else can be said when Brazilian President Luiz Inacio Lula da Silva shows up in Havana to see Fidel Castro?

And don't forget, Lula's visit comes on the heels of one by Chavez in late December. On that occasion, Chavez and acting Cuban President Raul Castro signed 14 energy agreements during the PetroCaribe summit in Havana.

Chavez and Castro signed the series of deals on Dec. 22, 2007, in the energy, mining, and oil sectors, including a $122 million loan for Cuba to buy tanker ships to transport crude oil and oil products from Venezuela.

Two agreements will see the southeastern Cienfuegos refinery more than double its capacity to 150,000 b/d, as well as reopen an oil pipeline from the refinery to Matanzas.

Ailments and oil

Brazilian officials said the main purpose of Lula's brief visit to Cuba was to see his ailing friend Castro. Castro, 81, has not been seen in public since emergency surgery forced him to cede power to his younger brother Raul in July 2006.

According to reports, Fidel's condition and exact ailment are state secrets, but those ailments did not prevent Lula and the Brazilians from getting their foot in the door, too.

"We've begun seismic analysis ahead of drilling operations," Petroleo Brasileiro SA Pres. Jose Sergio Gabrialli said at the signing ceremony that saw Lula and Raul Castro inking agreements for a number of projects, including joint oil exploration in the Gulf of Mexico.

Energy independence

Cuba hopes that exploration by foreign companies in deep waters of the gulf will result in discoveries that will enable the country to become self-sufficient in oil production.

The Cubans are not alone in thinking there's oil and gas in their deepwater offshore. According to the US Geological Survey, Cuba's area could contain 4.6-9.3 billion bbl of crude and 9.8-21.8 tcf of gas.

Fidel Rivero, president of Cuba's state oil company, said Petrobras already had already invested heavily in Cuba, but that the new agreement allows it to explore in the gulf for the first time.

"Important potential exists in this zone, and the idea is to study it," he said. He added that Cuba and Brazil would decide in the coming months just where oil prospecting would take place in 35 of the 59 areas Cuba has set out in its gulf territorial waters.

"They've got specialists and top technology," Rivero said of his Brazilian colleagues. "They're world leaders in deep water drilling."

The Brazilians are indeed leaders in deepwater drilling and that really spells the difference in their appeal to Cuba. While Chavez touts projects that require dependency on his country's oil, Lula is offering Cuba help in becoming energy independent. ✦

The El Huemul plant uses field gas with a high carbon dioxide content, which is consumed by the power plant without treatment. The equipment is scheduled to be delivered to the site by February, with installation and commissioning set for later in the first quarter.

Last week's power cuts coincided with an Argentinean government decision, in the wake of rising domestic prices, to suspend all exports of liquid fuels, including oil, gasoline, diesel, fuel oil, and naphtha.

Trade Secretary Guillermo Moreno also ordered that state-regulated prices return to levels in place on Oct. 31, 2007, a decision based on the so-called Supply Law passed in 1974 that requires suppliers of energy and other products to first meet domestic demand before exporting.

The Argentinean government will lift the ban once oil companies bring down gas oil and petrol prices to the Oct. 31 levels. Until then, the situation in the country will be monitored by the Argentine Trade Secretariat.

Raul Castellano, vice-president of Argentine hydrocarbons confederation CECHA, said it was an extreme move to cut all exports, but it should help to normalize prices on the domestic market, and that is absolutely necessary.

"The biggest problem in Argentina is not price but supply," Castellano noted.

While Argentineans may welcome the move, neighboring countries already are expressing concerns over their own potential supply problems resulting from Argentina's ban.

More than 50% of the fuels consumed in Paraguay are imported from Argentina, and the Argentinian ban might create serious problems for Paraguay, according to Blas Zapag, the head of Paraguayan company Copetrol.

Didier Olmedo, director general of economic policy of Paraguay's Ministry of Foreign Affairs, said Jan. 8 his country is concerned about the export ban decision to avoid shortages.

Olmedo assembled an emergency meeting with representatives of the Paraguayan Industry and Commerce Ministry and local fuels producers and distributors to discuss how to avoid a fuels shortage in the Paraguayan market.

Paraguay will officially report its concerns to the Argentine authorities via diplomatic channels, he said. ✦

KazMunayGas increases Kashagan share, influence

Eric Watkins
Senior Correspondent

Kazakhstan's state-run KazMunayGas will increase its interest in the Kashagan offshore oil project to 16.81%, equal to the shares of the other majority shareholders, according to Energy and Mineral Resources Minister Sauat Mynbayev.

The Eni SPA-led consortium confirmed Jan. 14 the signing of a new memorandum of understanding to settle the long-running dispute with the Kazakh government, saying its members would dilute their various stakes in the project to allow KMG to increase its stake.

The new agreement, effective Jan. 1, will result in Eni, ExxonMobil Corp., Total SA, and Royal Dutch Shell PLC each holding 16.81%, down from 18.5%.

The remaining two shareholders, ConocoPhillips Co. and Inpex Holdings Inc., will also see their stakes—9.26% and 8.33%, respectively—diminish, though officials did not state the percentage the two firms will surrender.

The consortium members also said they had agreed to a new operating and governance model and further unspecified financial components. "The agreement also includes a value transfer package from the consortium to the Kazakhstan authorities," the company said in a statement.

"Because this was part of a package agreement, we agreed the price for the additional stake at $1.78 billion plus interest accumulation up to the payment date. The payment will be made in three tranches following the start to oil production," Mynbayev said.

"Aside from the stake purchase, we also discussed a potential package of cash flows in Kazakhstan's favor," he added, explaining that the sum of the cash flows is about $5 billion or so-called net present value.

"That is the sum that will be paid to Kazakhstan over the life of the project," he said. "The project is scheduled until 2041; therefore the sum will amount to about $20 billion."

The Kashagan project is scheduled to start commercial production in 2010, delayed from an original date in 2005. Kazakh officials say Kashagan's total costs have jumped to $136 billion from an initial estimate of $57 billion. These cost increases and delays in startup and production are the reasons Kazakhstan gave for renegotiating the development contract (OGJ Online, Oct. 12, 2007).

The field has an estimated 4.8 billion tonnes of oil. Eni estimates that Kashagan will produce 1.5 million b/d of oil at its peak output.

In addition to the financial changes, "The sides agreed to implement a new operating model, one that involves forming a new operating company with the involvement of all existing consortium members, including [KazMunayGas], the role of which has increased considerably. It is under the control of this operating company that Agip KCO will bring the pilot phase to fruition," Mynbayev said.

"The manner in which the functions of the various participants are delegated thereafter is subject to further talks, without any major controversial aspects. This should be clarified before May," he said. ✦

Trinidad and Tobago bows out of PetroCaribe initiative

Eric Watkins
Senior Correspondent

The government of Trinidad and Tobago declined to join PetroCaribe, the trade initiative established by Venezuela, to assist Caribbean community countries in meeting their energy requirements in the face of price increases on the global oil market.

Prime Minister Patrick Manning said his administration would not sign the PetroCaribe initiative, as his country remains committed to the rival Free Trade Area of the Americas.

"We have convinced our Caricom colleagues to make Trinidad and Tobago the FTAA headquarters," Manning said. "They had gone out together with us to convince the Western Hemisphere system of this. How in the face of that could we now go and sign on to an agreement that scuttles the FTAA?"

Manning said the PetroCaribe initiative introduces a new trade structure that Venezuelan President Hugo Chavez is promoting to be known as the Bolivaria for the Americas.

"The PetroCaribe agreement is part of a more comprehensive set of prescriptions that Venezuela is advancing in competition to the established Western Hemisphere system. They have proposed the Bolivaria for the Americas instead of the Free Trade Area of the Americas," Manning said.

Apart from Trinidad and Tobago, Barbados is the only other Caricom state that has not signed the PetroCaribe accord, while others have embraced the pact with enthusiasm.

A recent statement by the Belize government, which will host the sixth PetroCaribe summit, said, "PetroCaribe has proven to be more than a trade mechanism for oil supply and currently constitutes a strategic framework for energy security also including cooperation to ensure efficiency and savings in the generation, distribution, and consumption of energy."

The Belize statement said the role of PetroCaribe also is an "ongoing creation by the Caribbean nations for an efficient subregional energy scheme, involving additional oil refining, storage, and transport capacity, an infrastructure for natural gas

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Economic cooling vs. global warming

It may be stating the obvious, but the essential Washington, DC, energy question now is the extent to which growing concern about the general US economy will divert political attention from global climate change.

Conventional wisdom holds that the economy always trumps the environment, especially when consumers—many of whom vote—start to complain about high prices. Global warming is part of the national vocabulary, but concern about it still doesn't resonate as much at the polls as middle class economic hardship.

It also is going to remain a key energy issue. The oil and gas association executives interviewed for the US Energy Politics special report were unanimous on that point (OGJ, Jan. 14, 2008, p. 20).

The executives also agreed that development of alternative fuels will be necessary, but American Petroleum Institute Pres. Red Cavaney and several others said funding research using new oil and gas taxes is still a bad idea.

'Spread the tax'

"It would seem to me if you believe new forms of energy are a panacea for concerns over the present energy mix, the federal government should dedicate general revenue funds to make the breakthrough and spread the tax across the general economy, Cavaney said. "When we decided to go to the moon during the 1960s, we didn't tax the airline industry."

Independent Petroleum Association of America Pres. Barry Russell said many climate change models don't consider consequences and regulatory difficulties surrounding alternatives such as nuclear power. "Our members who produce it believe natural gas will need to be part of the solution," he said.

"Somebody would have to pay for fuel mandates. Some members of Congress keep coming back to the oil and gas industry," warned National Petrochemical & Refiners Association Pres. Charles T. Drevna. "If they put domestic producers and refiners at a disadvantage to global competitors, it will hurt the US economy," he said.

Possible influences

Much will depend on what US President George W. Bush says in his 2008 State of the Union address on Jan. 28 about measures to stimulate the economy. He previously has rejected new taxes as impediments to growth, especially when they've been directed at a specific industry. But he changed the political atmosphere dramatically 2 years ago when he announced that America was addicted to oil.

Oil prices also will be a major force if they stay high, especially if publicly traded oil and gas producers report increased earnings for 2007. That probably will spur calls to tax supposedly excess profits, especially if retail regular gasoline prices approach $3.50/gal in May as the US Energy Information Administration forecasts in its latest Short-Term Energy Outlook.

Then there are the presidential and congressional campaigns. Remember Al Gore's comments late in the spring of 2000 when Chicago area retail regular gasoline prices climbed past $2/gal? ✦

export, import and processing, as well as education and training programs for energy industry personnel."

In early January, Balwin Spencer, the prime minister of Antigua & Barbuda, said that member states of the Petrocaribe association in the Eastern Caribbean would use an existing facility in his country to store and distribute fuel, instead of using installations in Venezuela.

Spencer said Antigua & Barbuda would acquire all of the outstanding shares in West Indies Oil Co. (WIOC) that it needs to be able to control an effective and efficient deposit and distribution center in the region. Reports say the installations belonging to WIOC can accommodate some 322,000 bbl of oil.

Earlier Spencer said the member states of Petrocaribe had been examining short-term and medium-term plans to improve and expand a port terminal in northeastern Venezuela to meet the needs of the eastern Caribbean. ✦

FERC issues final EIS for Broadwater offshore LNG terminal

Nick Snow
Washington Editor

Broadwater Energy's proposed offshore LNG project in Long Island Sound would have minimal environmental impacts under recommended mitigation measures, the US Federal Energy Regulatory Commission concluded on Jan. 11.

TransCanada Corp. and Shell US Gas & Power are jointly developing the project in New York state waters about 9 miles from Long Island's nearest shoreline and about 10 miles from Connecticut's closest shore. The terminal would be a floating storage and regasification unit (FRSU) that would be attached to a yoke mooring system (YMS), which includes a mooring tower embedded in the sea floor, according to FERC.

It said that the double-hulled FRSU would include a single berthing and unloading facility for LNG tankers with cargo capacities of 125,000-250,000 cu m, capacity to store as much as 350,000 cu m of LNG (equivalent to about 8 bcf of gas), a closed-loop natural gas-fired vaporization system, and utility systems, crew quarters, and service facilities.

The EIS said the terminal would receive LNG deliveries from tankers 2-3 times weekly, regasify it, and send out an average 1 bcfd of the fuel to a subsea gas pipeline that would extend 21.7 miles to an existing Iroquois Gas Transmission System pipeline in Long Island Sound.

FERC, which reviews applications to construct onshore US LNG terminals, is the federal agency responsible for final approval of this offshore project because it is in state waters. But the US Coast Guard is responsible for the FRSU's safety and security as a marine facility and for the LNG tankers while berthed and during transit in US territorial waters. The two agencies have shared reviews of the proposed project's engineering, reliability, and safety aspects since late 2004 when FERC initiated the prefiling process.

USCG's role

FERC said USCG already has issued a Waterways Suitability Report, which is an appendix in the final EIS. The US Department of Homeland Security service also will review and adopt pertinent portions of the EIS to satisfy its responsibilities under the National Environmental Policy Act and issue a final letter of recommendation with its final determination of whether the project's waterway is suitable for tanker traffic.

The final EIS indicated that the proposed Broadwater LNG terminal would have minimal onshore environmental impacts because it would be located in the sound. Primary impacts during construction would be physical disturbance of the sea floor and related turbidity in the water column. During operation, impacts of primary concern would consist of minor impacts on water quality, air quality, fisheries, recreational boating and fishing, and commercial vessel traffics. There also would be minor to moderate visual impacts.

"During our environmental review of the proposed project, we identified procedures that would avoid, minimize and mitigate environmental impacts that would result from construction and operation of the project as proposed by Broadwater. We recommend that these mitigation measures be attached as conditions to any authorization issued by the commission," FERC said in a statement.

They noted that the final EIS also evaluates alternatives to the proposals, including other energy sources, systems, sites, designs, and pipelines.

The final EIS indicated that the proposed project would begin with prelay pipeline installation surveys in September 2009. In-water pipelines would be installed from October 2009 to April 2010. The YMS would be installed in October and November 2010. The pipeline from the YMS to the IGTS pipeline would be built in November and connected in December.

The sponsors anticipate that design and fabrication of the FSRU and YMS would require about three years and proposes having the terminal operating in late December 2010, the final EIS said.

FERC said that commissioners will consider the staff's recommendation and final EIS before issuing a final decision on the project. ✦

Tanker protection is stretching USCG thin, GAO warns

Nick Snow
Washington Editor

The US Coast Guard's resources are being stretched thin as it assumes the lead role in protecting energy commodity tankers from possible terrorist attacks in or near US ports, the Government Accountability Office said Jan. 9.

The situation could become more critical, GAO warned in a newly released study, as LNG imports grow and more US terminals open. "Despite considerable efforts to protect ports and the energy traffic in them, the level of protection is not where the Coast Guard believes it should be. At some ports, Coast Guard units are not meeting their own levels of required security activities," it said.

The congressional watchdog service urged the US Department of Homeland Security to develop a national resource allocation plan that would balance the need to meet new LNG security responsibilities with other security needs and USCG missions. It also said DHS should develop federal-level guidance for ports to use in planning to help mitigate economic consequences, particularly when ports are closed.

The study also found that in several ports and regions, antispill and antiterrorist exercises occur separately and often do not include the same participants. Consequently, GAO recommended that the US homeland security secretary and the attorney general direct USCG and the Federal Bureau of Investigation, respectively, to develop coordinated national and local responses.

GAO originally prepared the report in March 2007, but released it publicly on Jan. 9 after removing sensitive security information, including details regarding security conditions and operations at specific ports and specific findings related to response plans and the results of exercises. It did not

perform additional audit work for the public version and generally did not change the March 2007 report's conclusions.

'Significant consequences'

The report's release produced some immediate congressional reactions. "If there was an attack on an energy tanker or terminal in a US port, there could be significant economic, environmental, and public safety consequences, which would result in even higher gasoline and heating oil prices," said House Energy and Commerce Committee Chairman John D. Dingell (D-Mich.), who requested the report last year with Ranking Minority Member Joe Barton (D-Tex.) and Rep. Edward J. Markey (D-Mass.), a committee member whose district includes the nation's only urban LNG import terminal.

Congress increased USCG's fiscal 2008 port security appropriation to $58.8 million from the $45 million that President George W. Bush requested, according to the committee. Dingell said he plans to review the White House's fiscal 2009 budget request to determine whether it has provided the necessary resources to protect energy tankers and ports, as identified in the report. "GAO's analysis reminds us of the urgent need to reduce energy imports and spur the growth of renewable and nonpolluting energy supplies," he said.

"Given the fact that LNG is being transported into Boston every several days on the way to the Everett LNG terminal, an attack on one of these tankers could be devastating," Markey said. "I will be working with my colleagues to ensure that DHS responds to the vulnerabilities exposed in this report and that their efforts are not hampered by a lack of resources. We cannot skimp when it comes to public safety."

Barton agreed that vessels delivering imported energy need to be protected, but added, "It also seems plain that simply accepting the inevitability of soaring natural gas imports is hardly a good idea, much less necessary, when America has vast reserves of energy available within our own boundaries. Yes, we'll need to protect the tankers, but we'll require far fewer of them if we can summon the political will to produce our own energy from our own reserves."

The latest report is the second by GAO in response to the three lawmakers' request, Barton said. The first, which came out in March, recommended continued research on technical safety issues, "and that makes perfect sense," Barton said. GAO also sent the most recent report to House Homeland Security Committee Chairman Bennie G. Thompson (D-Miss.) and Ranking Minority Member Peter T. King (R-NY).

Risks, responses

In that report, it noted that USCG has been assessing risks associated with certain dangerous cargo (CDC). "The results of that study, and of any comparative analysis that includes hazardous materials not on the CDC list, will be important in a careful and dispassionate analysis for ensuring that available resources are deployed in such a way that commodities receive protection commensurate with the relative risks involved. This is especially important with expected growth in LNG imports," GAO said.

It suggested that results of analyses from use of the Maritime Security Risk Assessment Model will be of similar importance in determining how field units can make the best use of security resources at their ports. "With the ability to compare different targets and different levels of protection offered by security stakeholders, the model should allow the Coast Guard to take a more complete accounting for the various risks at US ports," it said.

It said local USCG units have actively prepared for the coming growth in LNG shipments by working with local law enforcement agencies to augment resources. Such assistance is vital as the federal service tries to meet security requirements with limited resources, according to GAO. But it added that USCG's headquarters needs to help such local efforts more by beginning centralized planning for how to address resource shortages across several locations.

"As LNG facilities continue to multiply, the resulting increase in work load will affect some Coast Guard units but not others, necessitating a centralized response as well as a port-specific one," GAO said, adding, "It is important for the Coast Guard to begin this centralized planning soon, when attention can also be paid to assessing the options for partnering with state or local law enforcement agencies to ensure appropriate security."

Ports would need to provide an effective, integrated response to protect public safety and the environment, conduct a terrorism investigation, and restore operations quickly in the event of a successful attack on an energy commodity tanker, the report said. "Consequently, clearly defined and understood roles and responsibilities for all stakeholders who would need to respond are needed to ensure an effective response. Operational plans for the response, among the various levels of government involved, should be explicitly linked," it said.

The report conceded that ports may have exercise priorities other than responding to a terrorist attack on a tanker. But it also suggested that combined spill and terrorism response exercises should be considered and pursued in ports that are generally considered to be at risk.

Energy imports by tanker are concentrated in different regions, according to GAO. It said that in 2004 (the most recent representative year because hurricanes disrupted imports in 2005) Gulf Coast ports accounted for 62% of the oil arriving by tanker from abroad, East Coast ports handled 95% of the gasoline and 75% of the LNG, and ports on the West Coast received 60% of the jet fuel. ✦

US study commission calls for more alternate fuel R&D

Nick Snow
Washington Editor

The US government should be ready to spend $200 million/year over 10 years for additional research and development of alternatives to petroleum-based motor fuels, a federal transportation policy advisory commission recommended.

The activity could occur in conjunction and coordination with programs already under way at the US Department of Energy, the National Surface Transportation Policy and Revenue Study Commission said Jan. 15.

It said the evolution of energy security for US transportation will require "a true public-private partnership, one that provides incentives for the private sector to accelerate the development of widely developed infrastructure for alternative fuels and for the incorporation of multiuse elements in new developments and land use planning."

It urged Congress to establish accelerated tax credits and revolving loans to encourage early investments in alternatives. "Accelerated tax credits could also be made available to encourage the early transition of fleets and motor power away from dependence on petroleum-based fuels," it said.

The recommendation for additional alternative motor fuel R&D was one of nine the commission made in its new report, "Transportation for Tomorrow." It suggested new programs could be partially financed by increasing the federal fuel tax to 8¢/gal from 5¢/gal every year over 5 years and then indexing it to inflation.

US House Minority Whip Roy Blunt immediately criticized that idea as another attempt to enact new taxes. "As Congress and the administration work to create a package to stimulate our economy, it should be obvious that more than doubling the federal gas tax on working Americans would have precisely the opposite effect," he maintained.

Congress created the commission in 2005 when it passed the Safe, Accountable, Flexible, Efficient Transportation Act, according to information on its web site. Its 12 members represent federal, state and local governments; metropolitan planning organizations; transportation-related industries; and public interest groups. ✦

Cairn's Capricorn unit takes position off SW Greenland

Exploration off southwestern Greenland got a shot in the arm in mid-January 2008 when the Capricorn Energy Ltd. unit of Cairn Energy PLC, Edinburgh, took interests in six blocks.

The combined area covered by the six licenses exceeds 12.8 million acres, or the equivalent of 231 North Sea blocks. The blocks are in 300-1,400 m of water.

The Greenland Bureau of Minerals and Petroleum awarded Capricorn an 87.5% operated interest in the Sigguk and Eqqua blocks in the Disko West licensing round and a 92% operated interest in the Kingittoq and Saqqamuit blocks in the Open Door area. Nunaoil A/S, Greenland's national oil company, holds the remaining interest in those four blocks.

Capricorn also acquired a 40% nonoperated interest in the Atammik and Lady Franklin blocks off West Greenland. EnCana Corp., Calgary, operates those blocks with 47.5% interest, and Nunaoil has 12.5%. EnCana has held Atammik since 2002 and Lady Franklin since 2005.

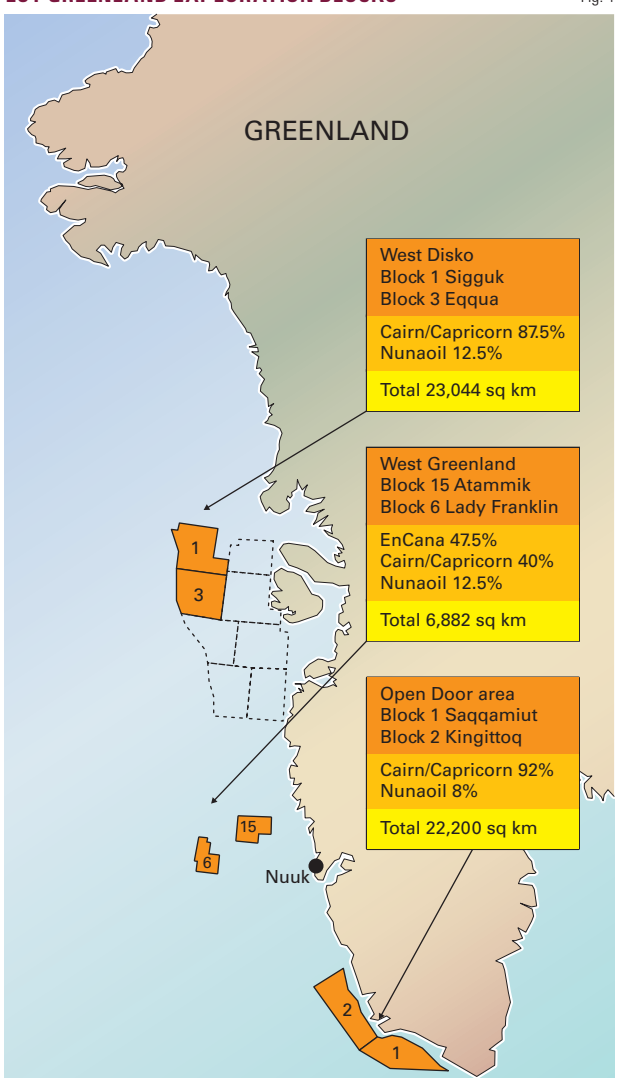
Cairn pointed out that Greenland has hosted only six offshore wells, one in 2000 and the rest in the 1970s.

The work program for Sigguk and Eqqua calls for shooting 6,000 line-km of 2D seismic in 2008-09. EnCana plans to run a seabed electromagnetic survey at Lady Franklin and Atammik in 2008-09. The Open Door blocks require 2,000 line-km of 2D seismic in 2008-09.

Meanwhile, Iceland approved its industry minister's proposal to offer oil and gas exploration and production licenses in January 2009 in the Dreki area on Jan Mayen Ridge northeast of Iceland (OGJ, Jan. 7, 2008, Newsletter). ✦

WEST GREENLAND EXPLORATION BLOCKS

Fig. 1



Source: Capricorn Energy Ltd.

Operators chase gas in three Alabama shale formations

Two emerging gas shale plays are running up against apparently steep learning curves in the Black Warrior basin and other geologic provinces to its east.

New participants, money, and equipment are about to be introduced into at least one of the plays.

One play is for gas in Middle to Late Cambrian Conasauga, and the other is for gas in Mississippian Floyd shale and Devonian Chattanooga shale.

The Conasauga play is more advanced and has the only production, Big Canoe Creek field in St. Clair County.

The top three Conasauga players have more than 800,000 acres under lease. That includes more than 500,000 acres for the 50-50 combine of Energen Resources Corp., Birmingham, and Chesapeake Energy Corp., Oklahoma City, and 300,000 acres for HighMount Black Warrior Basin LLC, Birmingham.

HighMount, a unit of New York's giant Loews Corp., operates Big Canoe Creek since acquiring it in mid-2007 from Dominion Black Warrior Basin Inc. (OGJ, June 11, 2007, p. 32).

HighMount is said to be planning to drill at least six new wells in the field using a rig or rigs capable of drilling to 15,000 ft. This is heavier equipment than that used by the previous operator.

Energen and Chesapeake filed permits in early January 2008 for two 12,500-ft wells in Bibb County some 95 miles southwest of Big Canoe Creek. They also permitted a 9,500-ft test in northern Greene County.

And Energen recorded a 36-month lease with Temple-Inland in northern Cherokee County, Ala., north of Weiss Lake in Broomtown Valley between Lookout Mountain and the Georgia line.

Meanwhile, rundowns posted on its website by the staff of the Alabama Oil & Gas Board in November 2007 detail efforts by several operators to drill, stimulate, and complete wells in the shale plays in the last few years.

The board's reports give details on wells in three counties in the Conasauga play and four counties in the Floyd and Chattanooga play (see map).

One board staffer said the status of the plays reminds him of the early 1980s when early coalbed methane wells were being drilled in Alabama.

ALABAMA SHALE PLAY AREAS

Fig. 1

Conasauga update

All of the Conasauga exploration has taken place in St. Clair County except for one well in Etowah County and one in Cullman County.

St. Clair and Etowah are northeast of Birmingham in the Valley and Ridge Province, and Cullman is north of Birmingham in the Cumberland Plateau Province.

Energen's Bibb County locations are 1 Marchant 22-16, in 22-22n-7e, and 1 Krout 10-14, in 10-22n-9e. The Greene County location is 1 Poole 1-5, in 1-23n-3e.

Big Canoe Creek operator HighMount adopted Dominion's Tuscaloosa staff.

As reported by the board, Dominion drilled 14 wells in the field to depths of 3,412-9,023 ft plus one well plugged at 958 ft with drilling problems before the sale to Loews/HighMount. Initial test rates reported to the board ranged from 26 Mcfd to 233 Mcfd.

Eight wells produced 6.8 MMcf of gas in August 2007. The most productive well, Burgess E28-11-58, made 2.684 MMcf of gas in August (OGJ, Sept. 24, 2007, p. 48).

Two of the most recent wells Dominion drilled are to TD 7,576 ft in 33-13s-4e and to 6,585 ft in 35-13s-4e. It cased and was attempting to complete both.

Dominion encountered lost circulation, swelling of clays, and wellbore drift at Big Canoe Creek due to the area's unique geological conditions, the board reported.

"Rock units in this area of the state are highly folded and faulted making geologic interpretations difficult. Thrust faults, which are low angle reverse faults, are the principal faulting mechanism in the area," the board said.

"These faults can cause an exaggerated thickness (up to several thousand

feet) for the Conasauga as a result of stacking of faulted strata."

Energen drilled two wells in St. Clair County in 2006 outside Big Canoe Creek field. The 29-12-101 Williams, in 29-14s-3e, went to TD 4,840 ft with production casing set to 3,522 ft and no test results reported. The 1 McAnulty 10-11, in 20-14s-3e, went to TD 2,365 ft and was plugged in 2007 due to drilling problems.

Energen also drilled the 1 GAA 23-12, in 23-12s-5e, Etowah County, plugged at TD 4,850 ft.

In Cullman County, Choctaw Geological Enterprises set a liner at 3,678-6,588 ft in Conasauga at the 1A Haynes Farms, in 26-9s-2w. This well site is one-half mille from a well that Shenandoah Oil Corp. and Occidental Petroleum Corp. drilled to 8,270 ft and plugged in 1972.

GeoMet Inc., Birmingham, has drilled the 06-07-04 Montgomery well in Cullman County to TD 1,998 ft and was waiting on completion rig.

Floyd-Chattanooga rundown

Exploration for Floyd-Chattanooga gas has occurred across a wider area than the Conasauga play but has resulted in little gas recovery so far.

Most of the drilling has been directed at the Floyd shale.

Lamar County

Lamar County action involved two wells by Denbury Offshore LLC, Plano, Tex., and a reentry by Samson Resources Co., Tulsa.

Denbury has produced gas intermittently since 2005 from a 2,000-ft southeasterly-trending horizontal lateral in Floyd shale at the 1 Burns 29-9, 29-17s-15w, southeastern Lamar County. It perforated the lateral at 5,350-6,820 ft measured depth at 4,856-85 ft true vertical depth. The well, acidized and hydraulically fractured in several stages, produced on 24-hr test at a rate of 80 Mcfd with 100 psi FTP on an open choke.

Denbury's 1 Crowley 26-7, in 26-16s-14w, southeastern Lamar County, has a 2,000-ft northerly horizontal lateral in Floyd. The board issued a temporary allowable test period effective Aug. 1, 2007, after Denbury ran a frac in the lateral at 5,118-22, 5,318-22, and 5,518-22 ft.

Samson plugged the 1 Patrick 32-10, a former Lewis and Carter gas well in McGee Lake field, Lamar County, in April 2007. It perforated the Floyd at 4,538-90 ft but decided against testing.

Pickens County

Murphy Exploration & Production Co.-USA has drilled and completed three Floyd wells in Pickens County and has filed no test results with the board on any of them. The 1 Exum Trust 6-16, in 6-21s-15w, west-central Pickens County, had selective perforations in Floyd at 6,438-6,617 ft and a frac in December 2005. Earlier the company perforated a Devonian interval at 7,130-48 ft.

In southeastern Pickens, Murphy cased the 1 O'Bryant 6-15, in 6-22s-14w, to TD 7,407 ft and perforated selectively at 7,018-7,133 ft in Floyd and ran a frac. In southwestern Pickens, Murphy cased the 1 Parker 3-16, in 3-22s-16w, to TD 8,800 ft. It perforated and ran fracs in Floyd at 8,451-67 ft and Chattanooga at 8,644-57 ft.

Wagner & Brown Ltd., Midland, Tex., reentered two wells in 2006 to test Floyd. The 1 McShan-Timberlands, in 11-19s-16w, northwestern Pickens, TD 5,785 ft, was deepened to 7,000 ft from 5,785 ft and cored the Floyd at 6,322-6,500 ft. Production casing was set to TD, but a Floyd completion was not attempted.

Wagner & Brown reentered the 1 Shaw Unit 10-10, in 10-18s-15w, north-central Pickens, set production casing to 5,167 ft, perforated Floyd at 4,954-66 ft and ran a frac but filed no test results.

In northeastern Pickens, Elysium Energy LLC, Denver, drilled the 1 Gulf States 29-11, in 29-18s-13w, to TD 5,267 ft with production casing set. Elysium ran a frac on Floyd shale perforations at 5,010-13 ft, 5,064-68 ft, and 5,107-11 ft but conducted no tests.

Tuscaloosa County

Jim Walter Resources Inc., Brookwood, Ala., drilled two wells in east-central Tuscaloosa County.

It spudded the 29-16-1 JWR well, in 29-20s-7w, in December 2005, reached TD 8,529 ft in February 2006, and set production casing at 6,500 ft.

It perforated the Fort Payne chert at 5,803-32 ft and 5,852-56 ft and set a bridge plug. It then perforated Floyd at 5,621-26 ft and 5,645-50 ft, but a frac screened out.

Jim Walter perforated Chattanooga at 5,946-61 ft in September 2007, ran a frac, and set a bridge plug. It ran another frac in October 2007 over the expanded interval 5,468-5,650 ft and used gas lift to remove water.

The 28-5-2 JWR well in 28-20s-7w was cased to 6,015 ft, perforated in Fort Payne chert at 5,726-70 ft, and acidized. The board issued the permit on Oct. 5, 2007, for the drilling of a 2,100-ft horizontal well bore in Floyd that has now been drilled to TD 7,593 ft, and the well is cleaning up after frac.

Blount County

The board is holding open hole logs confidential for 6 months from the GeoMet 19-15-1 Wittmeier, in 19-12s-1e, central Blount County.

It was drilled to 1,923 ft, where production casing was set, and deepened to TD 2,060 ft. GeoMet stimulated the open hole with nitrogen and installed a pumping unit.

GeoMet drilled the 30-03-02 Wittmeier in 30-12s-1e in November 2007 to TD 2,121 ft and was preparing to set production casing. It permitted the 30-02-03 Wittmeier in Sec. 30 to 2,500 ft.

Shannon J. Flicklinger, West Salem, Ill., drilled the 1 Hudson 16-7, in 16-10s-2e, northeastern Blount County, to TD 1,516 ft in June 2007 and was waiting on orders. No casing is set.

The site is 100 ft south of a well TD'd at 8,350 ft and plugged in 1980. ✦

Dongguo casing failures derive from many causes

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A program was instrumental in assessing the causes of casing failures and remediating them in wells in the Dongguo area of northeast China. The Dongguo area is part of Daqing oil field in Heilongjiang province.

Development of Dongguo has taken place during the last 13 years. With the drawn out exploitation program, the wells experienced problems, especially casing failures during the last 2 years.

These failures affected oil field development by complicating the proportion of fluids injected and produced, reducing oil recovery, restricting injection and production rates, and accelerating the production decline rate.

Dongguo

The Dongguo area has 136 oil producing wells and 175 water injection wells. The area produces about 276 tonnes/day of oil (2,035 bo/d), with 1,975 tonnes/day of total fluid lifted. The water injection rate is about 2,847 cu m/day (17,900 bw/d).

The produced oil is a paraffin-base crude oil with low sulfur content and a high pour point. Under formation conditions, the oil has a 0.795 g/cc density and a 6.74 cp viscosity. The reservoir had an initial 44.5 cu m/tonne GOR and a 7.85 MPa (140 psi) saturation pressure.

Under surface conditions, the oil has a 0.8535 gravity (34° API) and a 14.85 cp viscosity.

The injected water has 6.78 mg/l. of suspended solids, 4.68 mg/l. of oil content, 0.6 mg/l. of metratrophic bacteria, 60 mg/l. of sulfate reducing bacteria and 600 mg/l. of iron oxidizing bacteria.

The analysis indicated that the injected water caused little damage to the casing and attributed only about 2.5% of the damaged casings to injected water.

Casing failures

So far, the field operator has found 22 wells with damaged casing. Twelve casing failures were in oil producers and 10 were in water injectors.

The wells experienced two types of casing failures: deformation and fractures. Twelve wells had deformed casing, while 10 wells had fractured casing (Table 1). Fourteen wells had damaged casing away from the oil zone, while seven wells had damaged casing in the producing interval. One casing failure was not noted as to its location.

Eleven casing failures were in the Sa I, II interbed layer. Two casing failures were in the Sa 0, I interbed layer.

The number of wells with casing failures increased yearly, especially in wells that failed from deformed casing.

As seen in Table 1, 63.6% of the casing failures were in the nonoil layer. The casing failures in the nonoil layer zone were mostly in the X6-3-BW610 well district at the Sa I, II interbed layer.

There were 11 well casings in the

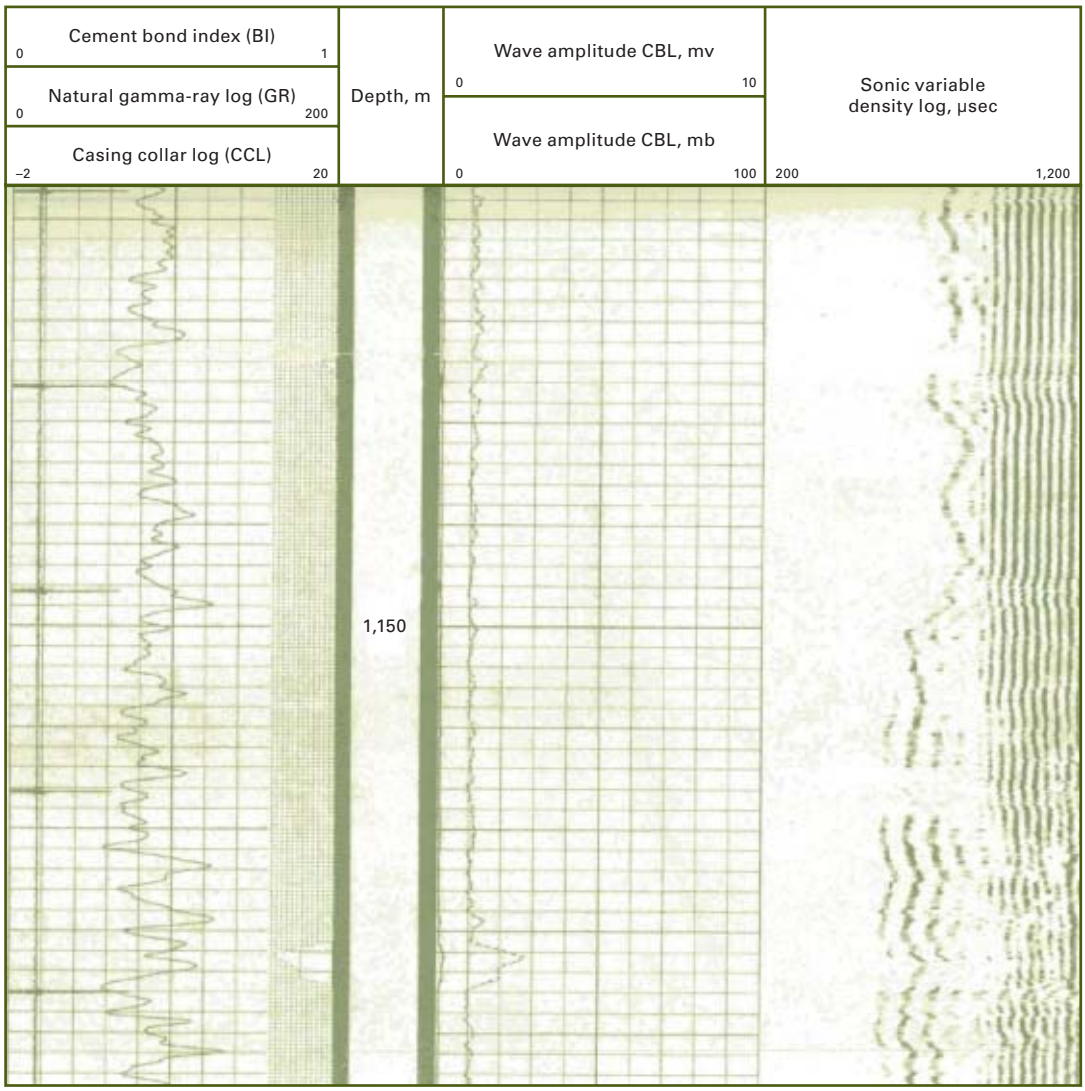
DONGGUO REGION CASING FAILURES

Table 1

Casing failure location	Layer	Well type	No. deformed	No. fractured	Total
Nonoil layer	SI, II interbed layer	Oil	5	2	7
	SI, II interbed layer	Water	1	3	4
	S0, I interbed layer	Oil		1	1
	S0, I interbed layer	Water	1		1
	N4	Oil		1	1
Oil layer	SII 6	Water		1	1
	SII 5	Water	1		1
	SII 11-1	Water		1	1
	SII 11-2	Water		1	1
	SII 1 middle shale	Oil	1		1
	SII 10 middle shale	Oil	1		1
	SII 2 bottom shale	Oil	1		1
Unknown		Water	1		1
Total		Oil	8	4	12
		Water	4	6	10
		Total	12	10	22

FIRST CEMENT BOND LOG

Fig. 1



Sa I, II interbed layer, and 5 of these wells went on production before 1998. Operation reports showed that damaged casing occurred in four wells between July and December 1998. Casing damage occurred in Well X6-3-B59 between March 2003 and April 2005. The other six wells are outlying, put on production in June 2004.

First, in terms of lithology, the grey and black shale is the primary rock in Sa I, II interbed layer in the outlying region where casing failures occurred. The top portion has an interbed layer with bentonite, which tends to break easily. A little water encroachment in the wells can therefore lead to failures.

Secondly, judging by variations of injection-production ratio, two casing failures in the X6-3-BW-610 well tract occurred after infill adjustment in 1998 and after outlying wells went on production in 2004. These two casing failures are both related to variations in the injection-production ratio.

After the first infill adjustment, the number of water-injection wells in the tract increased to 3 from the original 1 and the injection-production ratio increased to 1.19 from 0.

After the outlying wells went on production in 2004, the number of water injection wells increased to 13 from 3. One well was shut in because it did not take water and the other was shut in because of casing failure. The injection-production ratio in these wells increased to 1.22 from 0.32.

The injection-production ratio increased to 1.66 before the wells experienced casing damage and remains at 1.41 now.

The imbalance of water-injection pressure in this block also is a factor that can lead to casing failure. Fracture pressure changes from 12.69 MPa in the oil zone to 14.67 MPa in the transitional zone and then to 14.04 MPa in the outlying well zones.

Actual injection pressure changes from 12.6 MPa in the oil zone to 14.67 MPa in the transitional zone and then to 14.04 MPa in the outlying well zone.

The number of wells with damaged casing increased because of the strata sliding, which was caused by the pressure difference among different zones.

Another factor for the casing damage was that the number of outlying water injection wells in the Dongguo region was greater while the number of producing wells was lower.

Thirdly, if the well cement quality was poor, the injected water would enter the shale, causing the pressure to rise in the shale interval and lead to casing failure. Because of the low quality of cement at top of the perforated

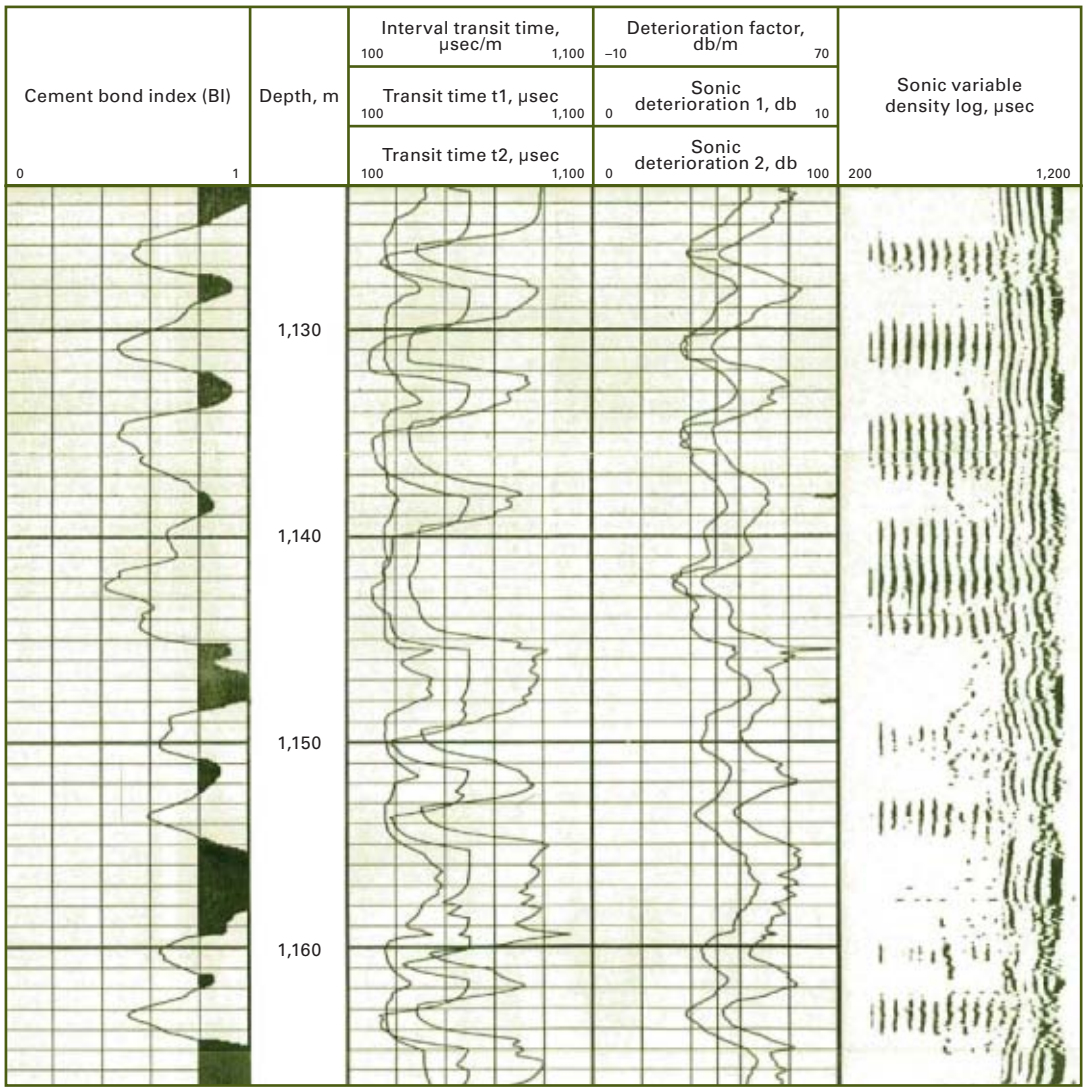
interval, injected water at the top of perforation was directly injected into Sa I-II interbed layer, so that the shale swelled and caused casing failure.

Figs. 1 and 2 show the first and second cement-bond log runs. The first log shows good well cement in August 2004 when the well was completed, but the second run in April 2006 shows poor cement quality.

Of the wells analyzed, seven had casing damaged in the oil layer. Reasons for the damage were attributed to the injection and production imbalance causing pressure buildup that led to small-scale fractures that allowed formation water to enter and swell the clay and shale layer, thus damaging the casing.

SECOND CEMENT BOND LOG

Fig. 2



Remedial treatments

The operator has repaired six wells, one oil and five injectors. Water injection resumed in the five injectors. To keep the pressure balanced in the casing failure zone, the operator started water injection at a moderate rate and increased pressure smoothly and slowly. The five wells have a designed injection rate of 370 cu m/day and actual injection rate of 209 cu m/day.

Production from the one producing well repaired is 3 tonnes/day fluid of which 1 tonne/day is oil.

To prevent more casing failures, the operator is controlling water-injection rates. After adjustment of the injection in three wells, the designed injection rate decreased to 20 cu m/day from 90 cu m/day with the actual injection decreasing to 9 cu m/day from 72 cu m/day.

At the same time, two production wells were remediated. One of the wells was hydraulically fractured and the other one had a larger, higher efficiency pump installed.

Liquid production from the wells increased to 45 tonnes/day from 24 tonnes/day, with oil production increasing to 12 tonnes/day from 3 tonnes/day.

After 1 year of remedial treatments and training of the staff in preventive measures, the operator has prevented additional casing failures.

Acknowledgment

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Life-cycle approach improves coalbed methane production

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UNCONVENTIONAL GAS TECHNOLOGY—Conclusion

This series on unconventional gas resources concludes with a discussion of technologies used in the recovery of coalbed methane and potential future research areas. The series has reviewed three main types of unconventional gas reservoirs: tight-gas, shale, and coalbed methane. The flow mechanisms of the different reservoirs increase in complexity from Darcy flow to Fick's diffusion flow, and include combinations of other mechanisms.

Many different technologies and methods have been effective in producing unconventional gas. Part 1 (OGJ, Dec. 17, 2007, p. 39).discussed tight gas reservoirs and included such processes as hydrajet fracturing.[3] Part 2 (OGJ, Dec. 24, 2007, p. 41) discussed shale gas and a variety of drilling, logging, and fluid treatment technologies.

Sorption

Coal's unique gas-storage mechanism is known as the "sorption" process, whereby gas molecules are packed tightly within the coal-matrix molecular pore system (Fig. 1). Concentration gradient causes gas to be released from the tens to hundreds of square meter surface area per gram of coal. Methane and other light gases diffuse (Fick's Law) from the coal matrix toward a lower concentration.

Coal can store many times its equivalent volume in gas because the gas molecules are packed tightly onto the surfaces of the coal. Gas adsorbed onto and within the coal macerals diffuses through a complex flow path of pores and cleats of varying sizes. The physics of migration is controlled by diffusion or diffusivity at various scales.

Some coals are diffusion limited, while others are not. Water and sometimes gas exist at equilibrium gas saturation. Concentration gradients are most readily generated by removing this water or gas from the cleat system by reducing reservoir pressure.[1]

Methane sorption isotherms are used to help define a relationship between gas storage capacity and reservoir pressure; from this, a critical desorption pressure can be determined. Conventional porous-media fluid-flow concepts, such as Darcy's law, relative permeability, and permeability anisotropy quantify reservoir mechanics after gas is released from the coal matrix. Methane extraction then occurs via a concentration gradient induced by removal of the free water or gas from the cleats as referenced above with effective stimulation or tailor-made well designs.

Coalbed methane

Conventional concepts can quantify reservoir mechanics after gas is released from the coal matrix, but coalbed methane (CBM) projects require earlier and more thorough evaluations than conventional projects. Therefore, CBM technologies, when viewed from a development life-cycle perspective, must depart from a conventional oil and gas approach in order to stack the odds for a commercial success.

Historically, CBM projects include a few top-tier wells and many average-to-marginal wells. Because CBM prospectors rarely understand the up-front controlling factors that make a good or bad well, an investment in a regional view and multiwell approach early in the program is necessary so that the economically viable wells or acreage can be identified during start-up.

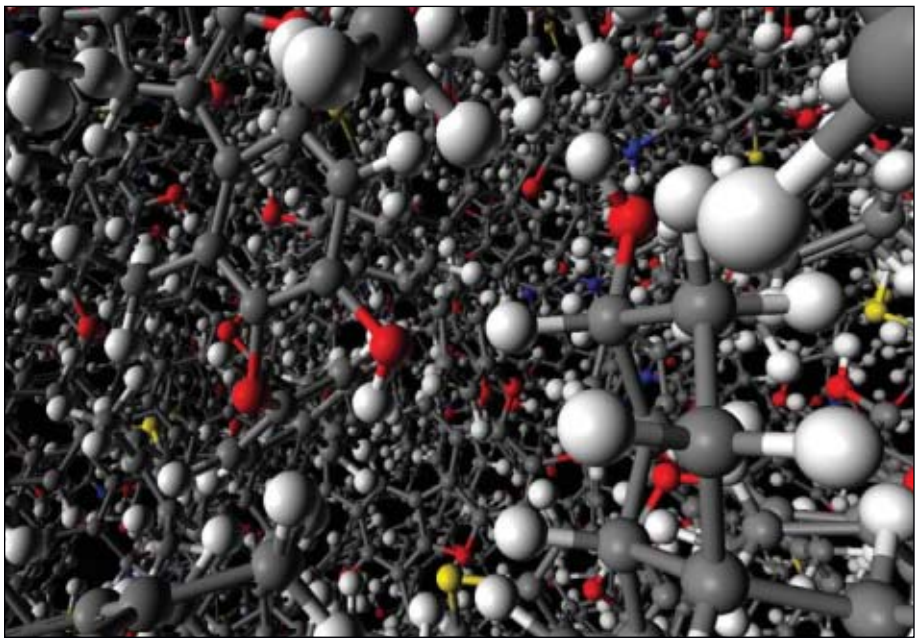
In a technology-play CBM project, innovative applications of enabling technologies allow prospectors and operators to reduce cycle time before the first commercial gas sales. They can also screen and high-grade potential projects, add value to preproduction knowledge gathering, and validate economic forecasts that often must project much further into the future than those of conventional oil and gas reservoirs.

Life-cycle concept

CBM projects have five distinct life-cycle phases:

1. Regional resource reconnaissance.
2. Local asset evaluation.

"Regulations and economics will require more efficiencies to be forthcoming."
—Glenda Wylie, technical marketing director of unconventional resources, Halliburton Corp.



Free gas and sorbed gas exist in the coal matrix. The model image shows a depiction of a typical subbituminous coal at the molecular level (Fig. 1).

3. Early development.
4. Mature development.
5. Declining production.

A large-scale project may contain multiple localized projects, resulting in the simultaneous occurrence of all life-cycle phases.

Fig. 2 presents a scenario in which an operator has leased several hundred thousand continuous acres of coal rights. The operator has been developing the asset for more than 15 years. Several areas in the lease are mature or experiencing declining production, but other areas have not yet been evaluated for production potential.

In Phase 1, an operator determines whether a property has adequate production potential to justify an acquisition and exploration.

In Phase 2, evaluations determine whether a specific area should be exploited and the most economic development methodology for exploiting it.

In frontier exploration plays or basins, cycle time and costs must be optimized. The economic issues of remote operations further drive development of innovative strategies to help reduce evaluation time and allow go/no-go Phase 3 decisions. Inherent highly variable coal-seam characteristics over short distances cause difficulties in extrapolating core hole and single test-well results. Consequently, basin-wide evaluations or localized testing should be performed before a multiwell production pilot or development phase activity.

In Phase 3, initiation of development drilling in potential areas and attaining targeted project production is critical for capital investment.

Phase 4 involves maintaining project production and economic targets through development of marginal areas, infill drilling, and remediation.

Phase 5 can result in secondary recovery efforts as a means of extending economic viability. Declining production requires plugging of unproductive wells, removing equipment, and restoring the site while maintaining a positive cash flow.

Fig. 3 illustrates a conceptual flow path for an example project. A phased approach may include separation of the single-cased well pilot holes as a Phase 1 effort. This phased approach can be further evolved into a "minipilot."

Enabling technologies

Over the years, many technologies and operating practices have evolved to help make CBM a viable energy resource. Ten specific enabling technologies may offer the best chance for projects to reach their life-cycle potential and span multiple life-cycle phases (Table 1):

1. *Geospatial well-pattern optimization.* CBM geospatial well-pattern optimization requires an understanding of CBM production mechanics and reservoir simulation for production and economic forecasting. Although well spacing is usually a north-south and east-west grid, optimized well patterns are determined by reservoir characteristics, completion effectiveness, well-stimulation effects, drilling and completion costs, operating costs, and outside factors.

For minimal cost, virtual simulation enables economic assessment, well-pattern comparisons, and completion options for hundreds of virtual wells.

2. *Core and core analysis.* Scientific analysis of coal core can be critical to the success of Phases 1 and 2. Calculating gas in place from direct core

ENABLING TECHNOLOGIES MATCHED TO CBM LIFE-CYCLE PHASES

Table 1

Enabling technologies	CBM life-cycle phase 1	2.1	2.2	2.3	3	4	5
Geospatial well-pattern optimization					X	X	
Core and core analysis	X	X					
Well logging	X	X	X	X	X		
Cleat permeability determination	X	X	X	X			
Reservoir engineering software tools	X	X	X	X	X	X	X
Prefracture diagnostics			X	X	X		
Hydraulic fracture stimulation			X	X	X	X	
Multiseam coiled-tubing hydraulic fracturing			X	X	X	X	
Secondary production enhancement						X	X
Infill drilling							X

measurements is a major first step in assessing methane gas reserves trapped in the rock matrix. Gas-content determination is largely independent of the core porosity and permeability, but is a function of methane adsorption within the coal macerals.

Prospectors may tend to rely on nonspecific seam lithotypes and assumed values for adsorption isotherms. Gas contents are calculated with assumed isotherms, reservoir pressures, and gross seam thickness. Although these estimates are appropriate during early prospect evaluation, they must be validated through direct-core measurement in Phase 2. A complete coal-seam anatomy can be obtained and applied to the macroscale reservoir.

3. *Well logging.* Significant technical breakthroughs in well logging have been developed specific to CBM. Perhaps the greatest advances involve log-processing methods and core-log integration techniques. Table 2 provides recommended log suites for projects in Phases 2 through 5.

Electric microimaging (EMI) logging may provide the closest thing to a continuous core as currently possible. It can be integrated with the whole core so that grayscale levels can be correlated to discrete core lithology. Such integration can be performed in one well and applied across the field or basin that lacks core information.

4. *Cleat permeability determination.* Three technologies are potentially available for cleat permeability determination and are applied predominantly through Phases 2 and 3:

- Openhole discrete-seam drillstem testing (DST).
- Interference testing and injection fall-off.
- G-function derivative analysis.

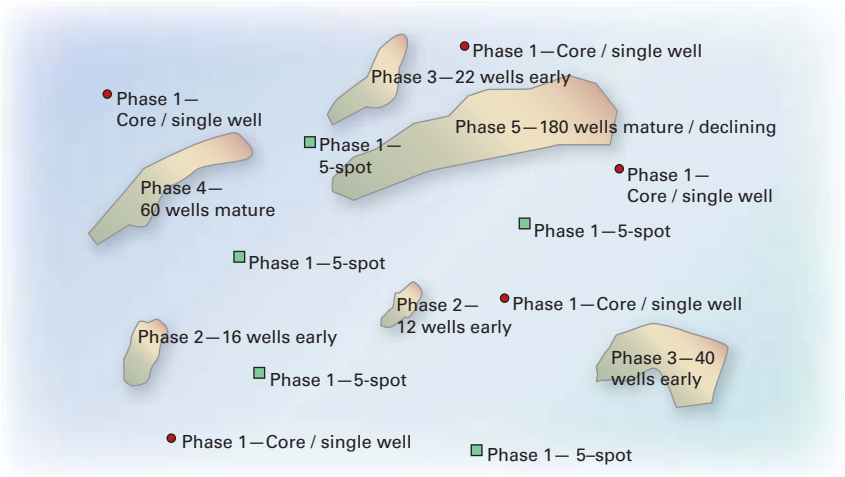
DST technology can enable the high-grading of discrete seams for subsequent production during the corehole process. Multiwell interference testing can enable the acquisition of far-field regional cleat permeability and permeability anisotropy. G-function analysis, primarily used for comparing regional variations, can enable near-field qualitative cleat permeability information to be obtained in conjunction with the hydraulic fracturing parameters.

5. *Primary hydraulic fracture stimulation.* Very few coal-seam gas reservoirs can produce commercial rates of methane without some type of primary production enhancement. Three primary proven stimulation technologies have been developed for enhancing CBM production: cavitation, underreaming, and hydraulic fracture stimulation. Historically, the most effective technology appears to be hydraulic fracturing although novel stimulated horizontal and complex wells are rapidly becoming viable alternatives to traditional vertical hydraulically fractured wells.

In the early phases, a technically, rather than economically, optimal fracturing system is critical to acquire valid gas and water producibility data for subsequent reservoir simulation

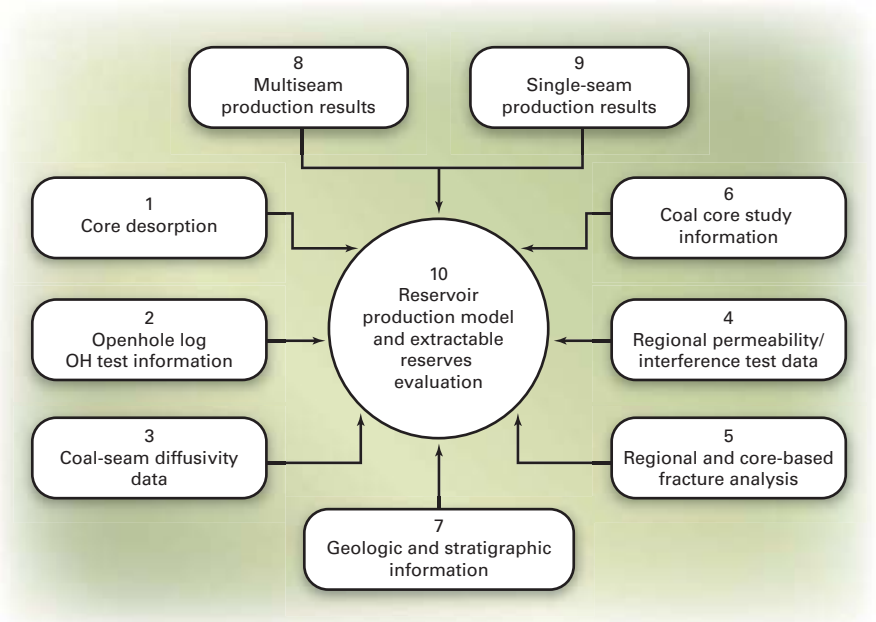
Project life-cycle phases

Fig. 2



Integrating resource-assessment, simulation data

Fig. 3



and sensitivity analysis. Early development of fracture-design simulation model(s) can match the outcome of the development-phase treatments and provide dependable predictions for future economic fracture treatments.

Recent technological developments have enhanced hydraulic fracturing for CBM resource evaluation. Because the indiscriminate application of fracturing fluids to coal reservoirs contributes to production performance, identifying an optimal fracturing system during resource evaluation phase is critical.

Economic constraints regarding mobilization and logistics, especially in frontier regions where little or no service infrastructure exists, largely drive fracture design decisions. If the goal of a single test well in a frontier region is to demonstrate that free gas can be produced to verify gas saturation, then a relatively small, low-cost hydraulic fracture design may be more appropriate than one designed for full-scale production.

6. *Secondary production enhancement.* During the final two life-cycle phases, technologies focusing on secondary production enhancement are increasingly important for extending the life of the CBM field.

Technologies enabling the extension of Phases 4 and 5 include the following:

- Hydraulic refracturing of previously fractured wells.
- Hydraulic fracturing of previously cavity-completed wells.
- Chemical-enhancement additives designed to mitigate specific impairment mechanisms included as part of the hydraulic fracturing system. Such remedial "backflush" technologies can be economic, repeated on the same well, and extend Phase 4 for years.

7. *Infill drilling.* Tapping into new reservoirs in a development field is an enabling technology because it has significantly helped extend Phases 4 and 5 of a mature CBM prospect. Because infrastructure investments have been capitalized, combining this approach with secondary production-enhancement methods offers a solution to stopping or stabilizing field or basin-wide production declines.

Reservoir modeling and history-matching the field's cumulative production can help identify infill-drilling candidates. Combined with geospatial well-pattern optimization, infill drilling can be optimized for a given asset within a basin or field. Emerging technology involving multilateral and directional drilling may eventually replace vertical-well infill drilling for CBM. Currently, economics are looking more favorable for widespread application of innovative multilateral and directionally drilled well completions in coal.

8. *Treatment selection.* Determining an optimum stimulation treatment involves experimentation, but the following guidelines can help operators avoid misapplications and decrease the learning curve. The following steps can be used for planning treatments in areas where few or no CBM completions have been performed.

Typically, coalbeds are categorized by:

- Type of coal, coal thickness, and stratigraphy.
- Proppant needs and desired proppant concentrations.
- Field economics, including service costs, accessibility and availability, and potential gas rates.
- Cleanup concerns or needs for long-term dewatering of well.
- Job design process, including frac-modeling simulation (pressure-dependent leakoff (PDL) concerns, rate effects, etc.).

When a well contains several coal seams that will act as producing zones, differences between zones may prevent the success of a single fracture design. Economics seldom allow operators to pump optimum jobs for each zone, even when the zones are fractured separately.

9. *Optimizing hydraulic technology.* Helping to define hydraulic technology should be considered early and evolve throughout the entire life-cycle, particularly in the local asset evaluation, single test well, and five-spot subphases. Fracturing fluids selection and optimization for hydraulic-fracturing technology is key in the local asset evaluation, single test well, and five-spot subphases. In these early phases, a technically optimal fracturing system is critical in acquiring valid gas and water producibility data for subsequent reservoir simulation and sensitivity analysis. Later in the well's life, emphasis can be shifted from technology to efficiency optimization.

Realistically, the time in which an optimum fracturing design can be achieved depends on several factors, including the following:

- The volume of available information about the seam(s) that will be fracture stimulated.
- How this CBM reservoir responds to fracturing compared to existing CBM reservoirs. Fracturing treatments that incorporate the use of fines control and surface modification agent (SMA) provide both fines and proppant flowback control. This allows the operator to produce the wells with the pump at or below the lowest perforations for optimum efficiency. Increased run times with fewer workovers improve the dewatering efficiency, shortening the time to maximum gas desorption.
- The technical background and

RECOMMENDED LOG SUITES FOR SPECIFIC PHASES

Table 2

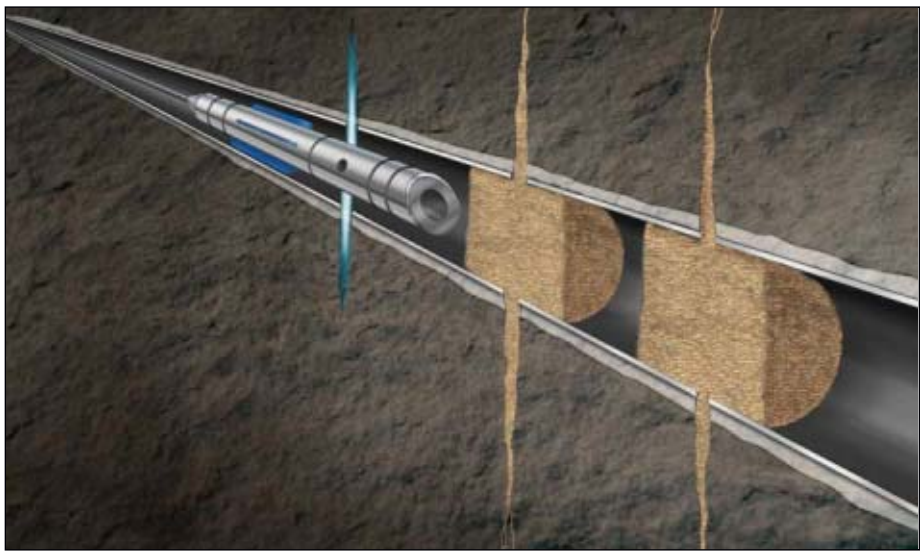
Log suite	Phase 2	3	4	5
High-resolution spectral density log	X	X	X	
High-resolution gamma ray	X	X	X	
High-resolution dual-spaced neutron	X	X		
High-resolution induction	X	X		
Microlog	X	X	X	
Magnetic resonance imaging log (if applicable)	X	X		
Electric microresistivity imaging log	X			
Wave sonic tool (dipole sonic)	X			
Thermal multigate decay pulsed neutron (if also evaluating sands) run through casing				X
Dual-spaced neutron (if not evaluating sands) run through casing				X

CBM stimulation experience of the team member(s) responsible for developing the fracturing program.

10. *Multiseam pinpoint hydraulic fracturing.* One of the most significant enabling technologies for CBM in recent years involves technologies that enable the hydraulic fracturing of multiseam completions.

Another fracture stimulation option for multiseam completions (not involving coiled tubing) is the conventional "Perf & Plug" method using conventional wireline perforating and composite bridge plugs that set quickly and are easily drilled out at the end of the completion.

Using coiled tubing, there are several new methods for isolating and fracturing individual coal seams, some of which involve hydra-jet perforating (Fig. 4). These methods were developed to minimize or eliminate non-productive time by planning the entire completion to be performed in a single trip. Coiled tubing fracturing technology allows placement of 30,000 to 100,000 lb/proppant per coal seam With pump time of about 1 hr/seam, three to seven stages have been successfully treated in a single day. For shallow CBM wells, as many as 24 intervals in two separate wells have been fracture stimulated in a single day with the same crew and equipment.



CobraMax fracturing service uses hydra-jet perforating and proppant plug diversion to fracture multiple intervals, vertically and horizontally (Fig. 4).

Defeating coal fines

A patented fines locking backflush service (FLBS) incorporating aqueous tackifier technology provides a process to help remove wellbore damage while locking down formation fines to restrict their mobility (CoalStim). It can be used during the initial stimulation job or in remedial stimulation jobs. FLBS chemicals initially act as "clotbusters," breaking apart the internal bridges and agglomerates, and then act as "clot-formers," imparting a "tacky" surface to the coal particle surfaces.

FLBS has been used to return hundreds of CBM wells in the western US to their initial production rates and extend the life of these highly profitable fields.

Other key functions of the FLBS chemistry are to degrade residual polymer remaining from previous gelled-fracturing operations and dissolve in situ geochemical precipitates or carbonate scales that may be contributing to premature production declines.

Coal fines tend to collect in both proppant and cleat porosity; eventually, such plugging may damage permeability and conductivity. FLBS causes fines to segregate and then adhesively bond together in larger groupings that bond onto proppant or cleat surfaces while keeping flow channels open to flow.

Benefits of applying FLBS post-fracture service in mature CBM fields include:

- Extend well productive life.
- Economically treat wells/field.
- Accelerate well pay out.
- Increase success rate.
- Lower financial risk.
- Add significant reserves to existing assets.

The fines control technology can be applied in both primary stimulation and remedial treatment application modes.

Field case history

A look-back study was conducted from a mature Phase 4 CBM project in the western US in which a total of 495 FLBS treatments were reviewed. The objective of the project was to extend the life of the field as it was approaching Phase 5. Results showed an average per well gas increase of 15,696 Mscf/well and 312 bbl/well increase in water over a 6 month period. This translated to an overall 4,500 % increase in gas volume and a project ROI of over 2000%.

Future technologies

No one individual technology can make unconventional assets profitable. A comprehensive holistic approach must be taken into account beginning with seismic and continuing through to last stage of production including plug/abandonment. Future exploitation of unconventional gas sources will require development and-or refinement of several technologies:

- Deformable proppants
- Partial monolayer proppant designs
- Proppant transport
- Improving proppants and fluids that are better tailored to formations.
- Create a better understanding of reservoirs by improving reservoir modeling and description
- Better prevention of circulation losses while drilling.
- Recycling and purification of water used in well-service functions.

- Reducing emission to the atmosphere
- Minimize land use through centrally located rigs and fixed-plant hydraulic fracturing operations serving many wells.
- Improved efficiency.
- Increasing simultaneous operations, e.g., drilling, stimulation, and production at the same time.
- Improving automation and real-time operations for improving learning and reducing manpower requirements.
- Improving recovery processes for ultra low pressure reservoirs, including improving artificial lift and improved recovery processes

Acknowledgments

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Glenda Wylie's biography was published in Part 1, OGJ, Dec. 17, 2007, p. 45.

Reactor revamp hikes hydrocracker performance for ULSD production

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North Atlantic Refining Ltd. implemented several key improvements to its hydrocracker including tailored catalyst systems, state-of-the-art reactor internals, replacement of air coolers, and avoidance of feedstock contamination. The joint effort resulted in a run length that is on target to be 1 year longer than the best cycle to date, more profitable product yield structure, and better ultralow-sulfur diesel (ULSD) quality distillates compared to previous cycles.

The refinery in Come By Chance, Newf., is equipped with a 37,000-b/d hydrocracker. Over the years, the hydrocracker faced similar issues as the rest of industry. The need to extend the cycle life and improve the product qualities became more obvious and urgent.

Hydrocrackers continue to be an excellent source of profit for a refiner due to the high-quality diesel blending components as well as the naphtha that they produce. To maximize profitability, improve reliability, and meet more stringent product specifications, however, refiners need to select the best catalyst systems, ensure good reactor flow distribution, and closely monitor feed properties.

Working closely with Criterion Catalysts & Technologies Co., Zeolyst International, and Shell Global Solutions allowed North Atlantic to justify and implement these key improvements.

Installation of Shell internals resulted in improved flow distribution in the reactors, increased catalyst utilization as evinced by the lower radial temperature profile in each of the catalyst beds, and made them more resistant to fouling. In addition, the same extent of conversion is achieved at 70% of the previously required axial delta temperature.

The combination of a new demetallization catalyst (RM-5030), improved pretreatment catalyst (DN-3300), and a tailored cracking catalyst system (TX trilobe shaped Z-673/Z-623) has allowed North Atlantic to achieve yield improvements, pressure-drop reductions, meeting ULSD specification for the entire cycle, and a record run length.

The expected economic benefit is $3.5 million/year.

Background

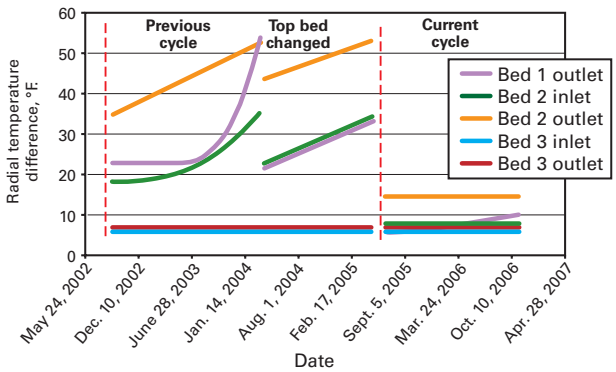
Refiners everywhere face the need to produce fuels to meet increasingly stringent specifications and remain competitive. Changing regulations, poor operational performance, and suboptimal yield structures based on feedstock or catalyst choices can reduce profitability.

Hydrocracking, a significant contributor to refinery profitability, is a robust and versatile conversion process.

Depending upon local market demand and refinery economics, hydrocrackers have been designed to produce primarily either naphtha or distillate products. The projected future increase in distillate demand and more-stringent quality specifications (e.g., ULSD, ce-

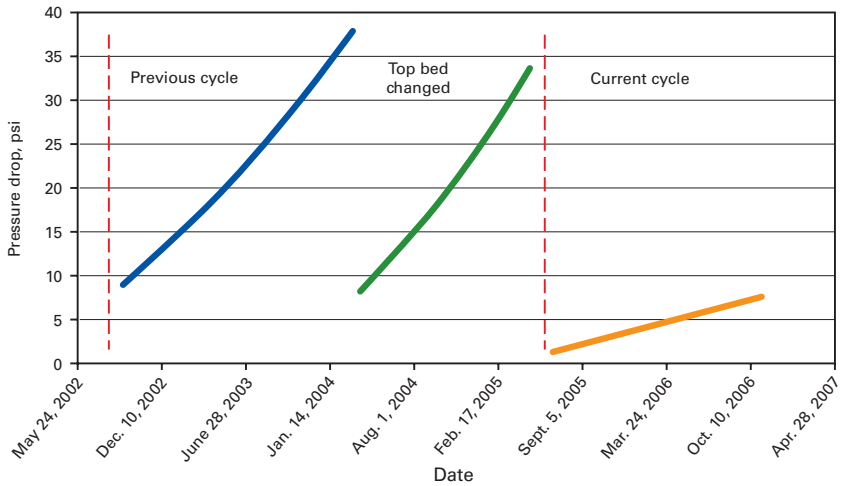
BED RADIAL TEMPERATURE PROFILE

Fig. 1



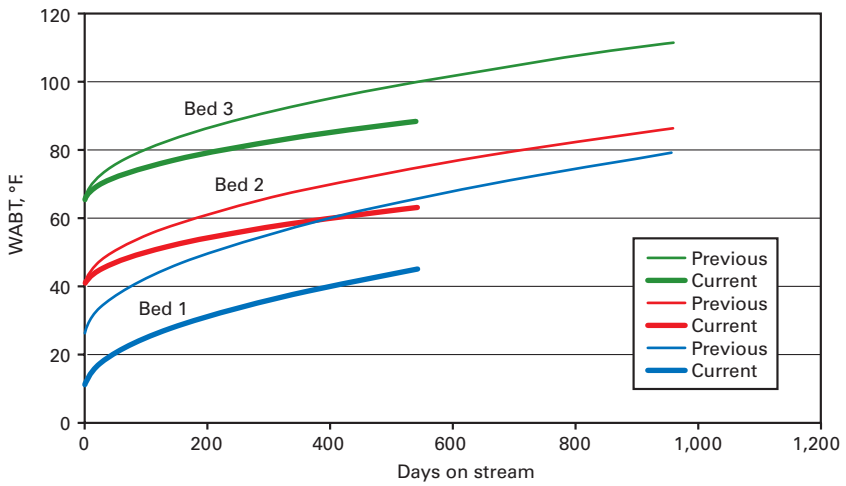
Reactor pressure drop performance

Fig. 2



Bed WABTs

Fig. 3



tane, aromatics) increase the incentive for hydrocrackers to operate in the most optimal and profitable ways.

Hydrocrackers that were designed as state-of-the-art 20-30 years ago in an environment of relatively low crude prices may not be as profitable as a unit designed recently.

Common requests from refiners to improve profitability and reliability of an existing hydrocracker include how to increase feed rate, how to process more difficult feeds (e.g., higher feed end point, FCC cycle oil, coker gas oil, deasphalted oil, synthetic feed), how to increase cycle life, how to produce the most profitable yield slates, and how to improve product qualities. The wish list could be extremely long such that there is no unique solution.

Close cooperation between the refinery, head office process engineering, technology providers, and catalyst suppliers is essential to identify profit enhancement opportunities and implement cost effective solutions for an existing hydrocracker.

North Atlantic Refining Ltd.

The history of the North Atlantic Refinery includes ownership by a number of different companies since its construction. Shaheen Resources originally built this oil refinery between 1971-73 with its first shipment of crude oil being refined in May 1973.

Shaheen operated the refinery until 1976 at which time the company went bankrupt and the refinery was shut down. The oil refinery was refurbished and brought back online 10 years later. In August 1994, North Atlantic Refining Ltd. purchased the refinery, and after a major overhaul, has been operating the 115,000-b/d plant since.

The refinery's location gives it access to petroleum product markets in Europe and the US Eastern seaboard and puts it close to sour crude supplies from Russia, Venezuela, and the Persian Gulf.

Operating opportunities

The hydrocracker at North Atlantic is a series flow, single-stage hydrocracker with two parallel reactors; each reactor contains three beds. For the last decade, the first bed in each reactor typically has contained a combination of demetallization and pretreat catalyst to remove feed contaminants and reduce nitrogen slip to protect the cracking catalyst in the second and third bed of each reactor.

The refinery has faced numerous issues concerning hydrocracker performance. In the early 1990s, a good cycle length was 9 months. As catalysts improved, and with additional focus on operational issues, the cycle length was extended to about 3 years.

There were, however, still issues with high deactivation rates due to processing visbreaker gas oils, with high-pressure-drop incidents due to upstream unit upsets, with an inability to control the temperature in the high-pressure separator during high ambient temperature periods, and with high radial temperature profiles in each of the catalyst beds. The refiner, therefore, decided to address all these issues during the current cycle.

The specific areas of technical improvement to the hydrocracker were:

- Optimizing feedstock selection and opportunity crude processing.
- Applying an advanced tailored catalyst system provided by Criterion and Zeolyst.
- Process improvements and instal-

lation of Shell Global Solutions reactor internals.

Feedstock improvements

Normally, processing visbreaker gas oils is profitable. Due to operational and separation issues, however, the visbreaker gas oils were more contaminated than desired for processing in the hydrocracker, which led to accelerated catalyst deactivation.

Criterion and Zeolyst provided North Atlantic with a yield and activity report for removing visbreaker gas oil from the feed. This confirmed North Atlantic's decision to remove this component from the feed until it could address the quality issues.

Another critical factor that influences hydrocracker profitability is unplanned contamination of the feedstock. During a review of the previous cycle, the refiner determined that the line used to transfer imported gas oil to tankage before feeding the hydrocracker was also used to transfer No. 6 oil to the wharf.

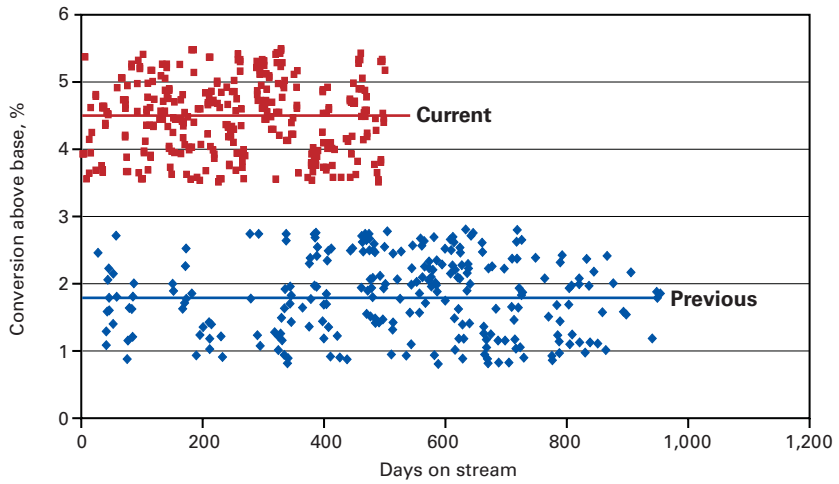
No. 6 oil contains more metals, sulfur, nitrogen, and carbon residue than the typical hydrocracker feed. When the procedure was reviewed, steps were added to confirm that the line was properly flushed so that the hydrocracker feed would not be contaminated with No. 6 oil. These steps were deemed important because the transfer of imported gas oil for the hydrocracker only occurs on a monthly or longer frequency.

Catalyst improvements

The relationship between North Atlantic and Criterion-Zeolyst started more than a decade ago when a cracking catalyst (Z-673) was custom developed by Zeolyst for North Atlantic's hydrocracker design, feedstock, and operating constraints. Subsequent improvements in demetallization catalysts and pretreat catalysts allowed North Atlantic to optimize the catalyst load further by including a more distillate-selective catalyst and further reduce the light gas production that constrains the hydrocracker at end-of-run.

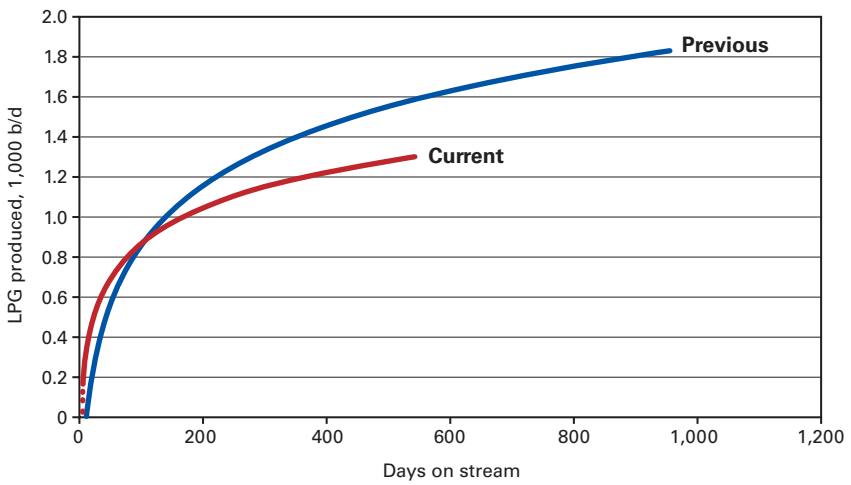
CYCLE CONVERSION

Fig. 4



LPG PRODUCTION

Fig. 5



Most recently, after extensive evaluation, the refiner chose a stacked bed of Zeolyst's high distillate selective cracking catalysts, Z-673 and Z-623, for this cycle. Another important catalyst parameter applied to this cycle is the new TX shaped version of Z-673 and Z-623 for pressure-drop reduction and other benefits.

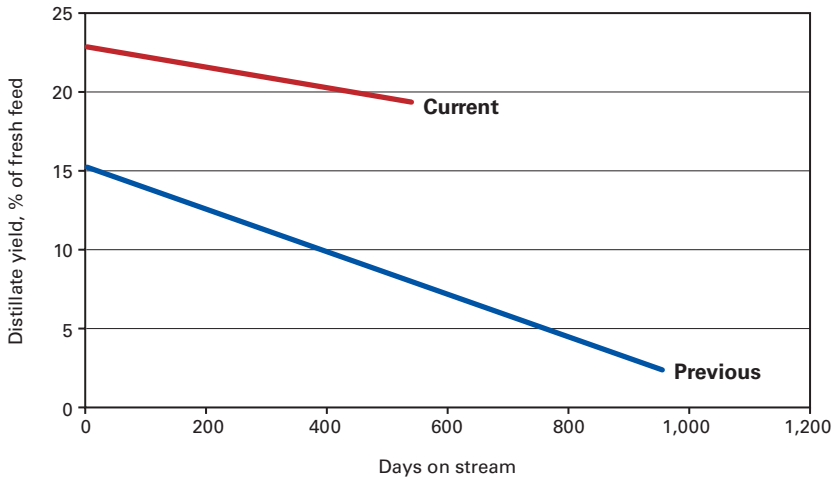
Replacement of older generation internals with new internals from Shell Global Solutions allowed the catalyst volume in the reactors to increase by 11%. Additional catalyst volume with the same loading method and same catalyst size leads to increased pressure drop. The unit, however, had previously faced premature end-of-run due to high pressure drop across the catalyst beds.

There were two pressure-drop issues. The first was excessive pressure drop across the first bed due to particulates and crust formation. The second issue was the total pressure drop across the reactor loop from compressor discharge to suction.

Additional catalyst volume allowed all of the partners to consider installing additional demetallization catalyst and grading material to deal with crust formation, but the total pressure drop issues still needed to be addressed.

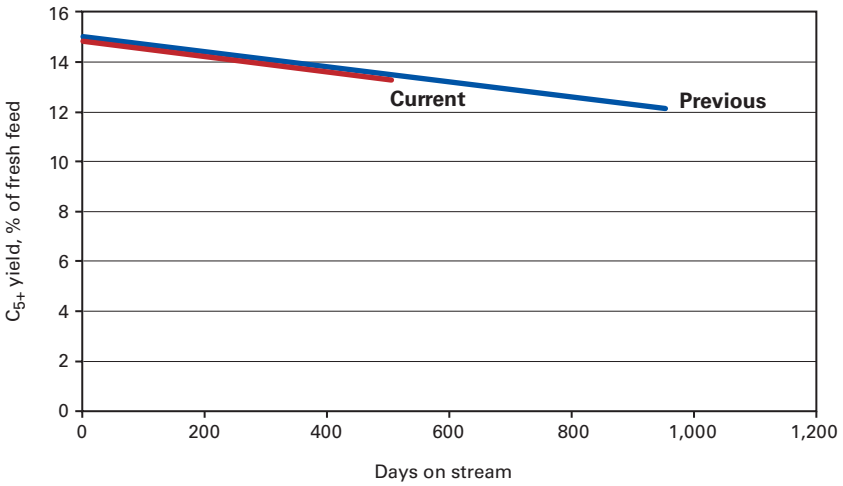
DISTILLATE YIELD FROM HYDROCRACKER

Fig. 6



C_{5+} TOTAL LIQUID YIELD

Fig. 7



Criterion and Zeolyst developed the TX trilobe shape to help mitigate the increased pressure drop due to the increased catalyst load.

This catalyst shape was presented in previous presentations.[1,2]

In addition to a new catalyst shape, the hydrocracker also used Criterion's improvements in demetallization and pretreat catalysts with installation of RM-5030 and DN-3300 in place of RN-412 and DN-3100 that were loaded during the previous cycle. The decision was made based on the commercial experience of up to 15° F. improvement in hydrodenitrogenation activity for DN-3300 vs. DN-3100.

Process improvements

As previously mentioned, another issue was inadequate control of the high-pressure separator temperature during summer operation. Although cleaning the air coolers helped in the past, North Atlantic decided to replace all 16 banks of the air coolers to take advantage of improvements in air-cooler designs developed during the last 30 years.

Although the cost of maintenance and cleaning was enough to justify replacing the air coolers, Criterion and Zeolyst provided further justification based on the run-length benefits of improving the purity of recycle gas in the hydrocracker.

Another important operating issue addressed was poor radial temperature distribution. A uneven temperature profile across the catalyst bed leads to unprofitable operation due to some catalyst being overworked relative to the rest of the catalyst in the bed. In severe cases, high radial-temperature deviations can lead to run limitations due to nonselective yields or temperature limitations.

Evaluation of available technologies led North Atlantic to select Shell Global Solutions internals, specifically its ultra-flat quench (UFQ) interbed internals, high-dispersion (HD) distribution trays, and top bed filter tray.[3,4]

The refiner installed a filter tray at the top of each reactor. In addition, UFQ and HD trays were installed between each bed.

Fig. 1 shows that the bed's outlet radial temperature profiles decreased to an average of 10° F. from 50° F. The uniform bed's outlet temperatures after the revamp show that exotherms are equal on the various bed locations. This proves uniform feed distribution. In addition, improved product selectivity is a strong indicator of a plug-flow type of reactor and thus a good uniform feed distribution in each reactor bed.

Fig. 1 shows the original bed radials, the radials following the changeout of the top bed (previous cycle), and the radials after replacing the internals and catalyst (current cycle), showing a minimal increase as the cycle continues.

An additional benefit of the new internals is increased catalyst-bed volume. The new internals allowed for about 11% additional catalyst volume. This additional volume was used to increase the active catalyst volume and to add more grading material and demetallization catalyst.

Fig. 2 shows that, compared on a constant-bed-depth basis, the start-of-run pressure drop decreased substantially due to the TX catalyst shape for

the cracking catalyst (two of the three beds in the reactor). Also, compared to past performance, the pressure-difference increase in the current cycle was mitigated via the Shell top-bed filter tray and top-bed grading system, both of which can remove and store fines without immediately plugging the catalyst system.

The first two curves in Fig. 2 show the reactor's pressure drop for the previous cracking catalyst cycle that included a top-bed replacement. The third curve is for the current cycle, showing the actual pressure drop. The lower rate of increase of the pressure drop confirms that the current cycle will not be pressure-drop limited.

The TX trilobe shape, installation of a filter tray, and bed grading in the additional catalyst volume allowed the catalyst activity instead of pressure drop to determine run length.

Performance, benefits

Due to all of these changes, the unit is more profitable. The weighted average bed temperature (WABT) has been lowered at higher throughput and higher conversion.

The previous cycle was about 32 months with an intermediate changeout of pretreat catalyst. The current cycle was proposed to be 48 months, but the hydrocracker is on track for a cycle that will approach 5 years with an intermediate changeout of pretreat catalyst. This extension of the pretreat catalyst cycle length and cracking catalyst cycle length translates into one less mini-turnaround and one less full turnaround during a 10-year period.

The current WABT is lower even though the feed rate and conversion have been higher and more consistent for this cycle than for the previous cycle.

The unit is currently running 10-15° F. less than a comparable point in the previous cycle. This activity advantage translates to a cycle-length extension of at least 1 year.

Although the overall WABT is lower than the WABT for the previous cycle, an additional benefit can be seen when the reactor beds' WABTs are examined individually. The lower radial temperature profile for each of the beds was one indication of better reactor flow distribution.

Fig. 3 shows another view of better catalyst utilization from the beds' WABTs. There are two improvements in the Bed 1 WABT. The first improvement is a lower WABT due to improved activity of the pretreat catalyst. The second improvement is a lower deactivation rate due to the improved flow distribution. This lower deactivation improvement is also present for the catalyst in Beds 2 and 3.

Each of the beds is currently operating at a WABT 10-15° F. less than a comparable point in the previous cycle, indicating an extension of the cycle by at least 1 year.

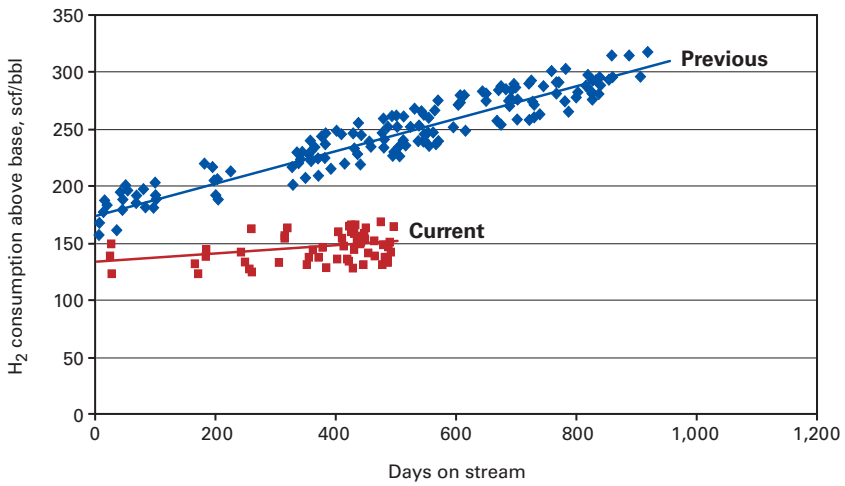
All of these WABT improvements are even more important when one looks at the unit's overall conversion change between this and the previous cycle.

Fig. 4 shows that, in addition to WABT improvements, the unit has been running more than 2.5% higher overall conversion this cycle compared to the previous cycle.

One of the critical end-of-run limits in the past has been excessive production of LPG due to poor selectivity.

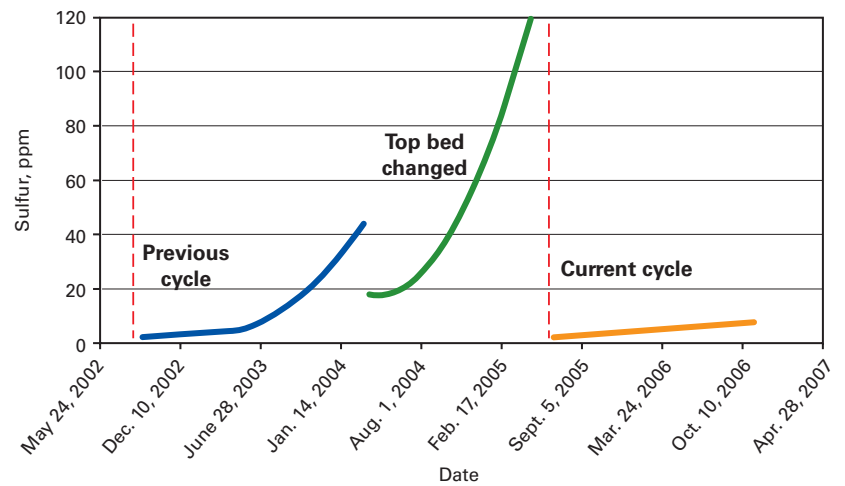
HYDROGEN CONSUMPTION

Fig. 8



FRACTIONATOR BOTTOMS SULFUR

Fig. 9



FRACTIONATOR BOTTOMS NITROGEN

Fig. 10

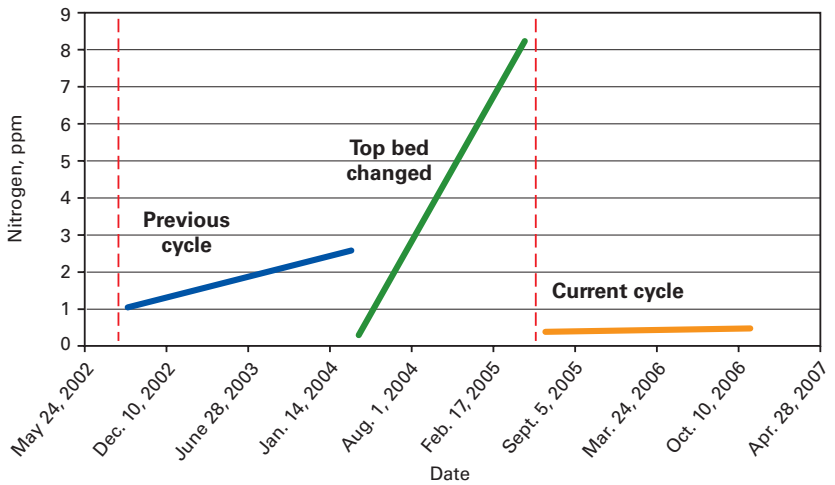


Fig. 5 shows that the combination of new internals with better catalyst utilization and the TX catalyst shape that further reduces nonselective overcracking has lowered LPG make from the hydrocracker. At this point in the cycle, LPG make is about 300 b/d less than the previous cycle. The reduction in LPG make will remove this constraint on the cycle length.

An additional interest for the refiner was increasing the total distillate make from the unit at constant overall conversion.

Fig. 6 shows total distillate yield. There are two points of interest that demonstrate the effect of good flow and temperature distribution in the catalyst bed. The first point is increased yield of distillate caused by the uniform use of all the catalyst in the bed (no overcracking in part of the bed leading to high radials). The second point is increased yield stability due to more uniform catalyst use and deactivation.

With the significant shift of products from LPG and light naphtha to heavy naphtha and distillate, the C_5+ liquid volume gain remained about constant with a slight decrease in hydrogen consumption.

Figs. 7 and 8 show these additional improvements in overall unit profitability. Fig. 7 shows the C_5+ total volume gain across the unit and Fig. 8 shows hydrogen consumption.

With the improved yields and product properties, diesel produced by the hydrocracker meets ULSD specifications during normal operations. This improvement allows for the reduction of sulfur analyses of the diesel to only those times when the unit is upset. Routine sulfur monitoring is now only conducted on the naphtha and bottoms streams because ULSD specifications will be met whenever the bottoms' sulfur level is less than 40 ppm.

In addition to the improvement in the fractionator bottoms API, there is a corresponding improvement in the sulfur and nitrogen levels remaining in the fractionator bottoms (Figs. 9 and 10).

All of these changes allowed the refiner to maximize catalyst activity to be used beyond the previous constraints of pressure drop, demetallization capacity, or nonselective yields. ✦

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GAS TURBINES—
Conclusion

Supersonic ejector saves fuel gas, reduces CO_2 emissions

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John Geerligs
NOVA Research & Technology Center
Calgary

Hasan Imran
TransCanada Corp.
Calgary

Several tests conducted on various configurations of a two-stage supersonic ejector to capture low-pressure gas and discharge it for reinjection into a higher-pressure stream for use as fuel gas arrived at optimum design and operating parameters. The optimum design gave an expansion pressure ratio (motive:suction) on the order of 14.0 and compression pressure ratio (discharge:suction) of around 8.1.

The first part of two articles (OGJ, Jan. 14, 2008, p. 54) summarized this optimum configuration of the supersonic nozzles, particularly for the first-stage ejector. This second, concluding article presents the performance test results of the integrated system and describes a successful implementation of the supersonic ejector unit at one of TransCanada's compressor stations in Alberta on a compressor-gas turbine unit rated at 24 Mw.

Integrated performance

Fig. 1 shows the integrated test rig with the two-stage ejector and the corresponding pressures, temperatures, and mass flow rate measurements. Tests conducted on the second-stage ejector alone optimized the position of its supersonic nozzle with respect to the diffuser inlet. Best performance occurred with the position of the nozzle exit at 1.42 mm upstream from the inlet section of the supersonic diffuser.

Varying P1 to the first-stage ejector (4,600 kilopascals-atmospheric, 5,000 kPa-a, and 5,500 kPa-a), while maintaining the motive-gas pressure (P_{in}) to the second-stage ejector at maximum line pressure of about 6,000 kPa-a tested the ejector's two-stage configuration.

Fig. 2 shows the results of the integrated

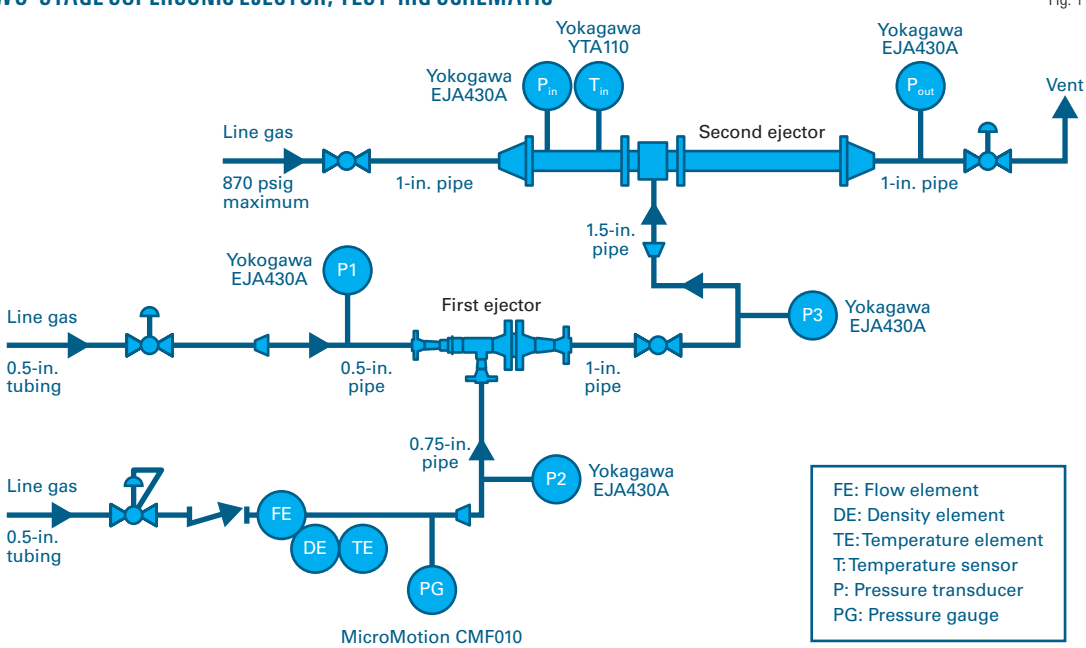
SUPERSONIC EJECTOR BENEFIT ON GHG EMISSION

Table 1

Ejector, second stage motive flow	0.4634 kg/sec
Motive gas, extra power needed	9,300 w
Motive gas, turbine extra fuel needed	31,000 w
Fuel heating value	39 megajoules/cu m
Fuel heating value	52,000,000 J/kg
Fuel gas burned	0.00059615 kg/sec
Greenhouse gas-CO_2 from this burning	0.00155 kg/sec
Greenhouse gas-CO_2 from this burning	48.8808 tonnes/year
Captured dry-seal vent gas	9 kg/hr
Captured dry-seal vent gas	0.0025 kg/sec
Heat energy equivalent	130,000 w
Heat energy savings	99,000 w
Greenhouse gas-CO_2, captured gas	0.0525 kg/sec
Greenhouse gas-CO_2, captured gas	1,656 tonnes/year

TWO-STAGE SUPERSONIC EJECTOR, TEST-RIG SCHEMATIC

Fig. 1



two-stage ejector system in terms of the discharge pressure from the second-stage ejector, suction flow at the first stage, and the intermediate pressure (P3) for different P1. Fig. 2a also shows the effects of varying (P1): The lower the P1 the higher the suction flow, but at the expense of overall discharge pressure (P_{out}).

This optimized configuration can deliver the required discharge pressure (P_{out}) of 3,300 kilopascals-gauge with a suction flow of 2-2.5 kg/hr and suction pressure (P2) of 340 kPag. These values match the requirements for this ejector to work with a dry-gas leakage and a typical fuel-gas line on a typical compressor station. Motive gas flow to the first stage is 0.016 kg/sec (based on 5,000 kPa-a pressure) and to the second stage 0.464 kg/sec (based on 6,000 kPa-a pressure).

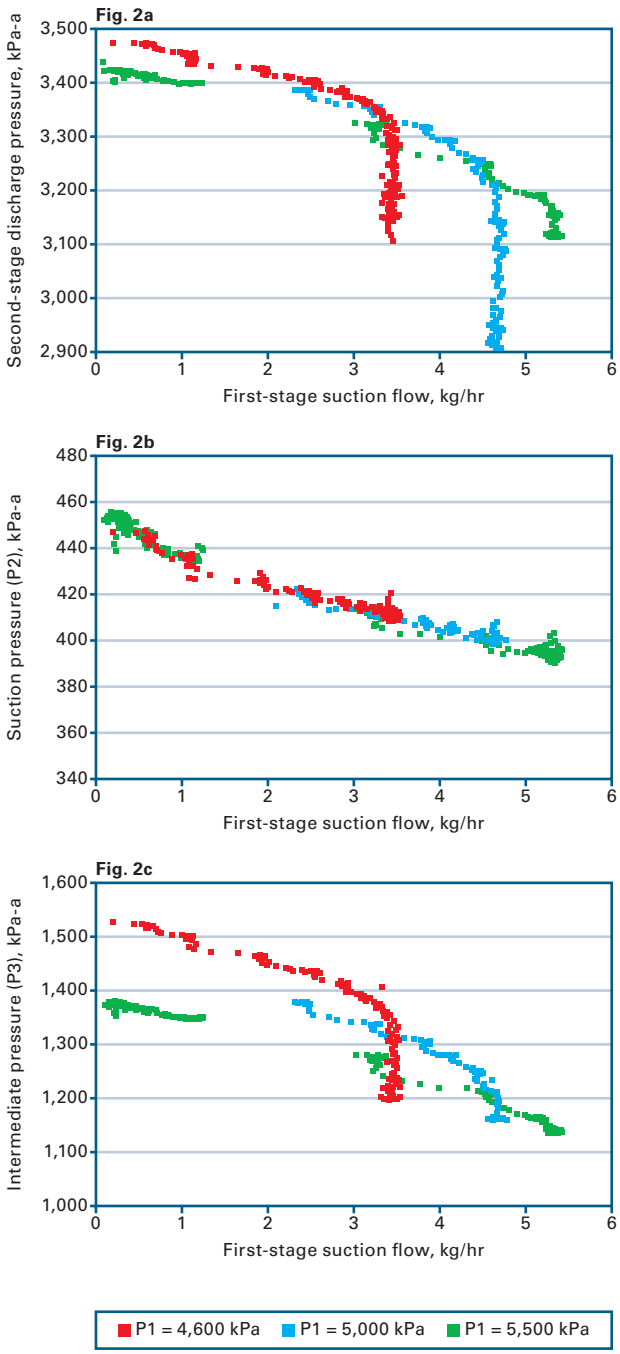
Recognizing that the motive gas to the second-stage ejector is drawn from the compressor discharge side (~6,000 kPag), allows assessment of the balance-of-plant with regard to net energy saved by capturing vent gas from the dry-gas seal. Compressor suction pressure of ~5,000 kPag and a pressure ratio of 1.2 yield excess power drawn by 0.464 kg/sec motive-gas flow of 9.3 kw.

Assuming thermal efficiency of the combined gas turbine-compressor of 30% results in 31kw extra fuel use due to motive-gas compression. Gas savings resulting from capturing the dry-gas seal vent gas of 9.0 kg/hr amounts to 130 kw (based on gas heating value of 39.3 mega J/cu m), leading to a total net energy saving in fuel gas of about 99 kw.

The supersonic ejector also reduces CO_2 emissions by 1,600 tonnes/year (Table 1).

TWO-STAGE SUPERSONIC EJECTOR PERFORMANCE

Fig. 2



Implementation plan

TransCanada plans to implement the newly developed gas-gas ejector system at its compressor stations system-wide based on results of real-time testing on a 24-Mw compressor at one of its stations in Alberta, skid-mounting the integrated two-stage ejector system with additional pressure gauges (shaded area, Fig. 3).

The chosen centrifugal compressor unit's high utilization hours led to its selection, allowing evaluation of the performance of the ejector system across a wide range of operating conditions and fluctuating loads. Ease of the shutting down the unit without interrupting service to customers also guided the selection process.

The seal-gas leak line currently going to atmospheric vent uses a flowmeter and a check valve. Table 2 gives the compressor's operating parameters, Table 3 provides the primary gas seal parameters both at the drive end, and nondrive end, and Table 4 details the selected compressor's fuel-gas system. These parameters guided the implementation design.

Fig. 3 shows the two primary dry-gas leakage lines from the two DE and NDE dry-gas seals connecting to form the suction to the first-stage ejector. Two check valves prevent any back flow into the seal area.

Adding backpressure regulators on the seal vents slightly modified the ex-

OPERATING PARAMETERS, SUPERSONIC EJECTOR IMPLEMENTATION

Table 2

Unit 1	
Suction pressure	4,613 kPag
Suction temperature	15.6° C.
Discharge pressure	5,801 kPag
Discharge temperature	34.7° C.
Speed	5,589 rpm
Efficiency	79%
Flow	58.29 kg/sec

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OIL&GAS JOURNAL

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OGJ Editor, Bob Tippee

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(webcast section)

The webcast will be based on the annual Forecast and Review special report appearing this year in the January 21st issue of Oil & Gas Journal. The Forecast and Review projects oil and gas demand worldwide and in the US for the new year. The US forecast analyzes demand by petroleum product (such as gasoline, diesel, jet fuel, and so forth). The Forecast and Review includes forecasts for US and Canadian drilling activity.

In addition to the 2008 forecast, the webcast will include past predictions compared with actual performance and industry trends for the previous four years. Bob Tippee, Editor, will make the presentation, with Marilyn Radler, Senior Editor-Economics, and G. Alan Petzet, Chief Editor-Exploration, on hand for questions. Marilyn assembles the numbers and writes copy for the supply-demand portions of the Forecast and Review. Alan does the drilling forecast.

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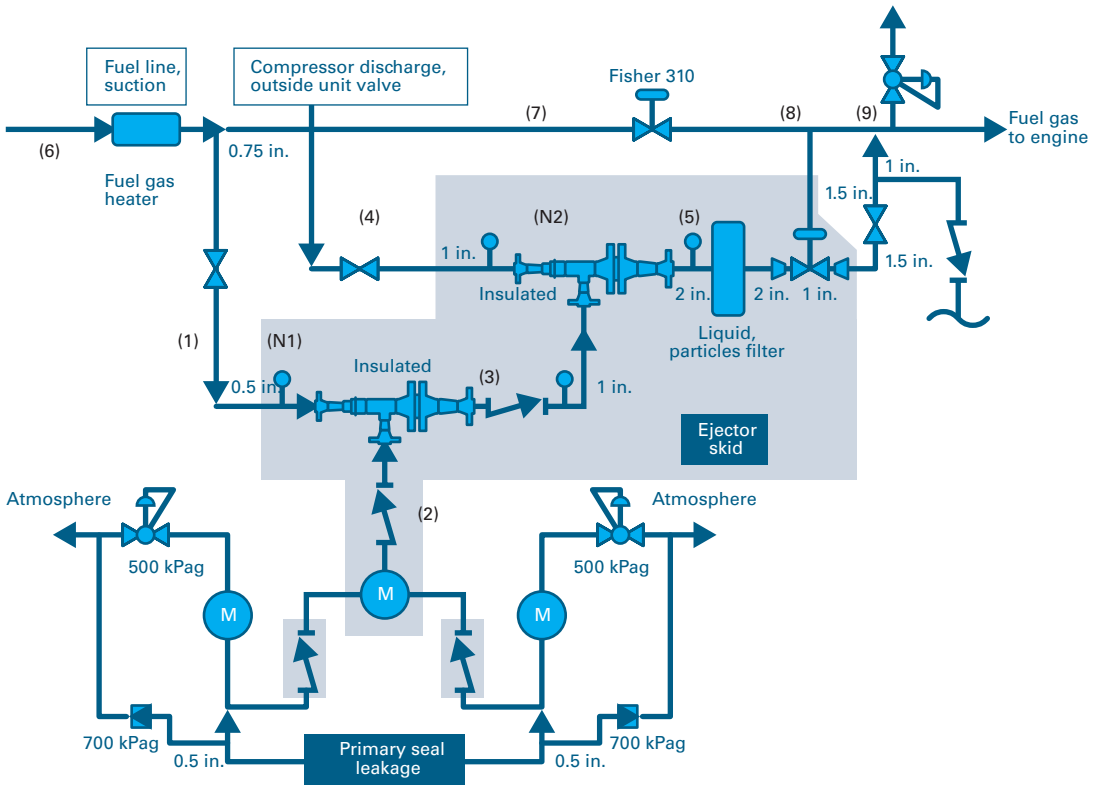
TWO-STAGE EJECTOR AT 24 MW COMPRESSOR

Fig. 3



DRY-GAS SEAL OPERATING PARAMETERS

Table 3

First stage vent gas seal, drive end			
Pressure	35 kPag	Alarm pressure	80 kPag
Flow	5 cu ft/min	Shutdown pressure	160 kPag
Flow	0.002 kg/sec	Rupture	700 kPag
First stage vent gas seal, nondrive end			
Pressure	6 kPag	Alarm pressure	80 kPag
Flow	2.5 cu ft/min	Shutdown pressure	160 kPag
Flow	0.001 kg/sec	Rupture	700 kPag

FUEL GAS SYSTEM OPERATING PARAMETERS

Table 4

Fuel gas	
Inlet pressure	4,610 kPag
Inlet temperature	15.6° C.
Pressure after heater	4,500 kPag
Temperature after heater	36° C.
Pressure after fuel regulator	2,700 kPag
Temperature after fuel regulator	23° C.
Flow	1.18 kg/sec

isting dry-seal monitoring system. Back pressure increased to 500 kPag from 160 kPag. The existing rupture discs rating remained static at about 700 kPag, with the shutdown set point set at 600 kPag. If the ejector cannot pull gas from the primary vent, these two regulator valves will vent the gas to atmosphere so as not to risk the dry-gas seal.

The rupture discs will continue to provide the same functions if pressure increases above 700 kPag. The increase in the back pressure on the primary seal to 500 kPag from 160 kPag will not damage the integrity of the dry gas seal.

First-stage motive gas came from a tie-in line from the outlet of the fuel-gas filter upstream of the Fisher 310 control valve. Pressure varies between 4,600 and 5,800 kPag. The compressor discharge line downstream of the unit valve supplied second-stage motive gas, typically at 6,000-6,600 kPag.

The supersonic nature of the two stages and the gas expansion through the respective nozzles results in extremely cold gas temperatures, corresponding to conditions inside the gas two-phase envelope. The exit velocity of the gas from the supersonic section, however, is extremely high, preventing thermodynamic equilibrium. Even if small condensation droplets formed, they would move at enormous velocity into the diffuser section of the respective stage and evaporate due to the diffuser's compression.

A gas coalescer filter installed on the ejector skid at Location 5 filters the final discharge gas from the ejector before in enters the fuel-gas line. Buffer gas is used to flush the seal chamber of debris or dirty gas, and keeping the seal environment clean requires use of the gas coalescer filter. Some buffer gas will eventually leak into the primary seal gas system and eventually into the fuel gas through the ejector, further reinforcing the need for the coalescer filter (Fig. 3).

A higher back pressure on the primary dry-gas seal could result in gas migrating to the secondary dry seal, located near the magnetic bearing cavities. Failure of the purge air and migration of the gas into the magnetic bearing cavities, combined with an ignition source inside the bearing cavities, could result in an explosion. It is, however, highly unlikely that anything would create an ignition source inside

the magnetic bearing cavities during start-up, shutdown, or the bearings being de-energized.

An outer seal labyrinth on the gas seal that has barrier air going to it, outboard of the secondary vent, makes it very difficult for gas to enter the bearing chamber. Any gas that gets across the secondary seal will be pushed out to the secondary vent by the barrier air, which should be vented to atmosphere.

An air purge to the bearing chambers, also vented to atmosphere, helps dispose of any additional gas that crosses the secondary seal. Positive pressure on the bearing housings should help keep process gas from entering. The barrier labyrinth should also help prevent combustible gas from migrating into the magnetic bearing chamber.

As long as the system is working properly, with barrier air flowing, there should be no process gas getting into the bearing chamber. The magnetic bearing design has no ignition source since the whole magnetic bearing assembly is sealed and should be contact-free (rotor and stator) with an air gap providing dampening and the magnetic field needed to achieve its function.

A differential pressure monitoring device, if working properly, will also trigger a unit shutdown on reversed pressure differential between the magnetic bearing cavities and the secondary dry seal; i.e., purge air or seal failure.

Table 5 shows data collected on June 23, 2007, after commissioning. Table 6 provides data taken on July 20, 2007, after 1 month of continuous operation. ✦

SUPERSONIC EJECTOR OPERATING DATA, JUNE 23, 2007

Table 5

Location	Pressure, kPa-a	Temperature, °C.	Mass flow, kg/sec	Mass flow, kg/hr
1	5,090	35.9	0.01770	63.720
Drive end seal	506	10.0	0.001607	5.785
Nondrive end seal	512	10.0	0.001607	5.785
Total seal leakage	509	10.0	0.003214	11.570
Nozzle 1	509	–113.0	0.01770	63.720
2	509	10.0	0.00286	10.285
Vent to ambient	509	10.0	0.00036	1.285
3	1,190	12.7	0.021	74.005
4	5,990	35.0	0.463	1,668.240
Nozzle 2	1,190	–68.0	0.463	1,668.240
5	2,990	8.2	0.484	1,742.245
6	5,140	10.0	1.177	4,237.500
7	5,090	35.9	0.693	2,495.255
8	2,900	23.0	0.693	2,495.255
9	2,690	18.4	1.177	4,237.500

SUPERSONIC EJECTOR OPERATING DATA, JULY 20, 2007

Table 6

Location	Pressure, kPa-a	Temperature, °C.	Mass flow, kg/sec	Mass flow, kg/hr
1	5,800	35.9	0.02017	72.612
Drive end seal	512	10.0	0.00214	7.704
Nondrive end seal	517	10.0	0.001696	6.106
Total seal leakage	515	10.0	0.003836	13.810
Nozzle 1	515	–113.0	0.2017	72.612
2	515	10.0	0.00250	9.000
Vent to ambient	515	10.0	0.00134	4.810
3	1,400	12.7	0.023	81.612
4	6,540	35.0	0.506	1,820.880
Nozzle 2	1,400	–68.0	0.506	1,820.880
5	3,160	8.2	0.528	1,902.492
6	5,850	10.0	1.177	4,237.500
7	5,800	35.9	0.649	2,335.008
8	3,100	23.0	0.649	2,335.008
9	2,690	18.4	1.177	4,237.500

Equipment/Software/Literature

Positive locking pins for oil field jobs

Kwik-Lok pins are available for a variety of construction applications—including cranes, scaffolding, drilling equipment, lifting equipment including hoists, slings, and cables, and in trailer beds. They are suited for any application requiring frequent connecting and disconnecting, lifting, changing, or securing objects without using tools. These positive locking pins are manufactured in a range of standard and special sizes to meet oil field needs, including MS and NAS, with lot number traceability on every pin. Standard sizes of more than 6,000 items are available immediately from stock; and special handle, material, and ball configurations can also be obtained.

Pins come in five handle styles: T, L, button, recessed button, and ring. Standard sizes range from 3⁄16 to 1 in. outside pin diameters in ½ in. to 6 in. grip lengths. Metric sizes include 5-25 mm OD in 10-100 mm grip lengths. All are made of stainless steel or carbon steel. Most pins are available in 17-4 PH stainless steel.

Source: **Jergens Inc.,** Jergens Way, 15700 W. Waterloo Rd., Cleveland, OH 44110-3898.

Oil field catalog; portable gas detectors

A new 42 page catalog, "3M Products for Maintenance, Repair & Operations," contains for every sector of the industry, from exploration and production to refining, transportation, and marketing. Products featured in the guide include abrasives, adhesives, cleaners, corrosion protection, electrical products, fire barriers, first aid supplies, lubricants, matting and treads, personal protection, sorbents, and tapes. For a copy of the guide, call 1-800-632-2304 or visit web site www.3m.com/oilandgas/mro.

Gas detectors. The company also introduces a line of easy-to-use, portable gas detectors to its lineup of safety equipment for the industry. The expanded spectrum of detectors includes the multigas detector 950 Series and 740 Series.

The 950 Series detector can identify as many as five gases simultaneously. The 740 Series is designed for durability, convenience, and low operating costs, and is suited for use in operations where potentially hazardous levels of CO, H_2S, O_2, or combustible gases may be found.

Source: **3M,** 3M Center, St. Paul, MN 55144-1000.

Services/Suppliers

Geoservices,

Le Blanc-Mesil, France, has appointed Bruno Laforge vice-president, human resources. Laforge will also serve on the Geoservices executive committee and report to Managing Director Philippe Salle. Laforge has more than 13 years of experience as human resources director for three companies dating to 1995. He also was career and training manager for Sollac and project manager, competencies definition, for Cogema, during the early 1990s.

Laforge

Geoservices provides a range of oil field services in 60 countries, focused on evaluating hydrocarbon reservoirs and optimizing field exploration, development, and production. The company offers mud logging, well intervention, and field surveillance services.

Baker Hughes Inc.,

Houston, has appointed Jan Kees van Gaalen vice-president and treasurer, replacing Douglas Doty, who retired in July 2007. Van Gaalen previously worked for PT Inco Tbk., where he served as chief financial officer. He also held a variety of finance positions with Anglo America PLC, Carlton Communications PLC, and Schlumberger Ltd. Van Gaalen has a bachelor's degree in economics from Erasmus University, Rotterdam, and an MBA from the HEC Management School in France.

Baker Hughes is a leading provider of drilling, formation evaluation, completion, and production products and services to the worldwide oil and gas industry.

EMS Group,

Houston, has appointed Milo "Budd" Melvin as director of EMS Canada, a wholly owned subsidiary of EMS Group. Melvin, based in Calgary, will oversee and manage business development and operations throughout Canada. Previously, Melvin was a market segment leader at Champion Technologies, a Houston specialty chemicals company serving the oil and gas industry.

EMS also disclosed that it will consolidate its two wholly owned subsidiaries Celtic Controls Inc. and K&D Oilfield Services into EMS Canada to better meet the operations and maintenance needs of Canada's pipeline industry.

EMS provides a full range of operations and maintenance services to major pipeline operators, local distribution companies, and independent power, oil, and natural gas producers.

Fulbright & Jaworski LLP,

Houston, has continued to expand its global energy practice with the London office appointment of Stefan Ricketts, who previously served as BG Group's general counsel. Ricketts will later move to the firm's Hong Kong office.

Fulbright's global energy practice includes more than 220 lawyers who regularly are involved in international and domestic energy matters.

Imports of crude and products

	Districts 1-4 1-4 2008	Districts 1-4 12-28 2007	District 5 1-4 2008	District 5 12-28 2007	Total US 1-4 2008	Total US 12-28 2007	Total US [1]1-5 2007
	1,000 b/d						
Total motor gasoline	916	1,140	104	11	1,020	1,151	1,033
Mo. gas. blending comp.	462	676	58	11	520	687	597
Distillate	131	326	—	—	131	326	475
Residual	361	259	20	—	381	259	400
Jet fuel-kerosine	37	114	129	21	166	135	270
Propane-propylene[2]	110	199	19	17	129	216	118
Other	760	399	–9	119	751	518	643
Total products	**2,777**	**3,113**	**321**	**179**	**3,098**	**3,292**	**3,536**
Total crude	**8,486**	**8,717**	**1,320**	**1,292**	**9,806**	**10,009**	**9,505**
Total imports	**11,263**	**11,830**	**1,641**	**1,471**	**12,004**	**13,301**	**13,041**

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

Purvin & Gertz LNG netbacks—Jan. 11, 2008

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.73	4.95	6.28	4.84	5.59	6.20
Everett	6.63	4.34	6.23	4.41	4.97	6.95
Isle of Grain	9.49	7.07	8.92	6.94	7.74	8.79
Lake Charles	5.51	3.37	5.25	3.56	3.88	6.20
Sodegaura	5.94	8.34	6.19	8.01	7.25	5.19
Zeebrugge	7.46	5.15	6.77	5.05	5.77	6.78

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

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	13,940	57,970	30,082	9,434	48,682	13,713	4,541
PADD 2	61,864	50,806	17,587	7,713	29,871	1,201	19,802
PADD 3	141,149	64,351	29,172	11,961	32,863	16,310	24,719
PADD 4	13,241	6,323	2,003	555	3,200	396	[1]2,451
PADD 5	52,647	33,613	26,408	10,053	14,077	5,754	—
Jan. 4, 2007	**282,841**	**213,063**	**105,252**	**39,716**	**128,693**	**37,374**	**51,513**
Dec. 28, 2007	**289,577**	**207,842**	**101,315**	**39,026**	**127,177**	**39,595**	**54,367**
Jan. 5, 2006[2]	**314,686**	**213,295**	**95,014**	**41,462**	**140,965**	**44,066**	**59,769**

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

Refinery report—Jan. 4, 2008

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d						
PADD 1	1,522	1,521	1,626	94	552	118	64
PADD 2	3,347	3,316	2,197	206	1,018	59	229
PADD 3	7,707	7,661	3,565	740	2,167	301	768
PADD 4	496	493	306	17	146	13	[1]142
PADD 5	2,849	2,780	1,422	454	606	96	—
Jan. 4, 2007	**15,921**	**15,771**	**9,116**	**1,511**	**4,489**	**587**	**1,203**
Dec. 28, 2007	**15,584**	**15,382**	**9,070**	**1,463**	**4,275**	**670**	**1,171**
Jan. 5, 2006[2]	**15,909**	**15,603**	**9,190**	**1,580**	**4,446**	**591**	**1,122**
	17,436 operable capacity		**91.3% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*1-11-08	*1-12-07	Change $/bbl	Change, %
SPOT PRICES				
Product value	102.73	61.82	40.92	66.2
Brent crude	96.79	51.67	45.12	87.3
Crack spread	5.95	10.15	–4.20	–41.4
FUTURES MARKET PRICES				
One month				
Product value	103.97	61.85	42.12	68.1
Light sweet crude	94.70	53.50	41.20	77.0
Crack spread	9.28	8.35	0.93	11.1
Six month				
Product value	106.14	70.24	35.90	51.1
Light sweet crude	92.55	58.12	34.43	59.2
Crack spread	13.59	12.11	1.48	12.2

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

Statistics

OGJ GASOLINE PRICES

	Price ex tax 1-9-08	Pump price* 1-9-08	Pump price 1-10-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	270.0	309.7	222.9
Baltimore	265.6	307.5	225.6
Boston	268.0	309.9	228.4
Buffalo	259.5	319.6	247.0
Miami	267.4	317.7	244.1
Newark	272.4	305.3	221.2
New York	248.8	308.9	242.2
Norfolk	274.4	312.0	216.6
Philadelphia	256.0	306.7	248.4
Pittsburgh	258.7	309.4	232.5
Wash., DC	268.9	307.3	235.4
PAD I avg.	264.5	310.4	233.1
Chicago	290.7	341.6	256.1
Cleveland	263.4	309.8	213.4
Des Moines	265.9	306.3	210.7
Detroit	258.1	307.3	210.4
Indianapolis	264.8	309.8	210.9
Kansas City	261.6	297.6	204.5
Louisville	269.5	306.4	213.1
Memphis	267.6	307.4	214.9
Milwaukee	257.7	309.0	223.5
Minn.-St. Paul	265.6	306.0	209.3
Oklahoma City	259.6	295.0	200.2
Omaha	260.8	307.2	213.5
St. Louis	270.4	306.4	208.2
Tulsa	261.8	297.2	204.8
Wichita	251.5	294.9	204.3
PAD II avg.	264.6	306.8	213.2
Albuquerque	268.9	305.3	214.2
Birmingham	259.5	298.2	217.4
Dallas-Fort Worth	254.7	293.1	219.6
Houston	255.7	294.1	216.6
Little Rock	258.3	298.5	215.7
New Orleans	268.3	306.7	217.9
San Antonio	256.0	295.3	215.1
PAD III avg.	260.3	298.7	216.6
Cheyenne	258.9	291.3	207.2
Denver	262.2	302.6	210.2
Salt Lake City	261.0	303.9	224.6
PAD IV avg.	260.7	299.3	214.0
Los Angeles	271.8	330.3	261.2
Phoenix	256.8	294.2	236.1
Portland	272.0	315.3	266.8
San Diego	279.8	338.3	267.8
San Francisco	294.8	353.3	283.6
Seattle	268.9	321.3	280.3
PAD V avg.	274.0	325.4	266.0
Week's avg.	**264.9**	**308.5**	**226.6**
Dec. avg.	**257.0**	**300.6**	**228.5**
Nov. avg.	**264.0**	**307.6**	**223.7**
2008 to date	**262.1**	**305.6**	—
2007 to date	**186.0**	**229.6**	—

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

REFINED PRODUCT PRICES

	1-4-08 ¢/gal		1-4-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	247.10	New York Harbor	268.30
Gulf Coast	244.35	Gulf Coast	262.80
Los Angeles	256.60	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	237.95	ARA	267.54
Singapore	253.81	Singapore	265.62
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	247.60	New York Harbor	186.62
Gulf Coast	244.60	Gulf Coast	184.76
Los Angeles	258.60	Los Angeles	197.88
		ARA	194.41
		Singapore	191.61

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

BAKER HUGHES RIG COUNT

	1-11-08	1-12-07
Alabama	1	6
Alaska	7	9
Arkansas	47	36
California	42	35
Land	40	33
Offshore	2	2
Colorado	103	91
Florida	0	0
Illinois	0	0
Indiana	1	0
Kansas	14	14
Kentucky	8	7
Louisiana	139	190
N. Land	48	54
S. Inland waters	18	21
S. Land	27	48
Offshore	46	67
Maryland	1	0
Michigan	1	1
Mississippi	11	20
Montana	12	18
Nebraska	0	0
New Mexico	69	86
New York	5	9
North Dakota	47	33
Ohio	10	11
Oklahoma	190	183
Pennsylvania	21	16
South Dakota	0	0
Texas	859	789
Offshore	11	12
Inland waters	2	2
Dist. 1	15	17
Dist. 2	35	25
Dist. 3	67	59
Dist. 4	92	95
Dist. 5	181	143
Dist. 6	118	124
Dist. 7B	34	35
Dist. 7C	54	47
Dist. 8	117	102
Dist. 8A	19	25
Dist. 9	47	45
Dist. 10	67	58
Utah	39	44
West Virginia	30	27
Wyoming	73	85
Others—NV-4; TN-6; VA-4	14	7
Total US	**1,744**	**1,717**
Total Canada	**515**	**586**
Grand total	**2,259**	**2,303**
Oil rigs	327	269
Gas rigs	1,409	1,444
Total offshore	59	83
Total cum. avg. YTD	**1,759**	**1,706**

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	1-11-08 Percent footage*	Rig count	1-12-07 Percent footage*
0-2,500	62	3.2	50	2.0
2,501-5,000	101	52.4	102	53.9
5,001-7,500	219	26.9	236	19.4
7,501-10,000	436	1.8	414	3.3
10,001-12,500	426	4.2	420	2.3
12,501-15,000	277	0.3	251	—
15,001-17,500	117	—	124	0.8
17,501-20,000	71	—	78	—
20,001-over	30	—	41	—
Total	**1,739**	**8.1**	**1,716**	**7.4**
INLAND	38		34	
LAND	1,649		1,619	
OFFSHORE	52		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]1-11-08	[2]1-12-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	659	782
California	646	678
Colorado	49	58
Florida	5	5
Illinois	28	27
Kansas	91	92
Louisiana	1,361	1,327
Michigan	15	15
Mississippi	48	49
Montana	93	98
New Mexico	172	164
North Dakota	106	115
Oklahoma	164	174
Texas	1,346	1,314
Utah	43	50
Wyoming	143	147
All others	61	69
Total	**5,045**	**5,184**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	1-11-08
Alaska-North Slope 27°	87.07
South Louisiana Sweet	96.00
California-Kern River 13°	80.00
Lost Hills 30°	88.80
Wyoming Sweet	84.19
East Texas Sweet	88.75
West Texas Sour 34°	81.75
West Texas Intermediate	89.00
Oklahoma Sweet	89.00
Texas Upper Gulf Coast	85.75
Michigan Sour	82.25
Kansas Common	88.00
North Dakota Sweet	84.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	1-4-08
United Kingdom-Brent 38°	98.42
Russia-Urals 32°	93.98
Saudi Light 34°	93.02
Dubai Fateh 32°	90.19
Algeria Saharan 44°	98.28
Nigeria-Bonny Light 37°	98.52
Indonesia-Minas 34°	98.34
Venezuela-Tia Juana Light 31°	93.85
Mexico-Isthmus 33°	93.74
OPEC basket	95.13
Total OPEC[2]	93.56
Total non-OPEC[2]	92.15
Total world[2]	92.93
US imports[3]	88.41

[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]

	1-4-08	12-28-07	1-4-07	Change, %
	bcf			
Producing region	864	922	934	–7.5
Consuming region east	1,511	1,604	1,716	–11.9
Consuming region west	375	395	382	–1.8
Total US	**2,750**	**2,921**	**3,032**	**–9.3**
	Oct. 07	**Oct. 06**	**Change, %**	
Total US[2]	**3,567**	**3,452**	**3.3**	

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

International rig count

Region	Dec. 2007 Land	Dec. 2007 Off.	Dec. 2007 Total	Dec. 06 Total
WESTERN HEMISPHERE				
Argentina	87	0	87	81
Bolivia	2	0	2	3
Brazil	21	25	46	33
Canada	358	2	360	456
Chile	1	1	2	1
Colombia	40	0	40	21
Ecuador	9	0	9	12
Mexico	68	30	98	84
Peru	6	2	8	6
Trinidad	0	5	5	7
United States	1,749	62	1,811	1,718
Venezuela	58	13	71	76
Other	2	0	2	2
Subtotal	**2,401**	**140**	**2,541**	**2,503**
ASIA-PACIFIC				
Australia	10	11	21	22
Brunei	1	2	3	4
China-offshore	0	22	22	17
India	55	29	84	85
Indonesia	44	22	66	53
Japan	1	1	2	1
Malaysia	0	11	11	14
Myanmar	7	0	7	10
New Zealand	4	1	5	6
Papua New Guinea	1	0	1	1
Philippines	0	1	1	1
Taiwan	0	0	0	0
Thailand	3	8	11	11
Vietnam	0	4	4	6
Other	1	2	3	4
Subtotal	**127**	**114**	**241**	**235**
AFRICA				
Algeria	29	0	29	25
Angola	2	3	5	4
Congo	2	1	3	1
Gabon	3	1	4	3
Kenya	0	0	0	0
Libya	14	1	15	13
Nigeria	2	7	9	11
South Africa	0	0	0	0
Tunisia	4	1	5	5
Other	2	2	4	5
Subtotal	**58**	**16**	**74**	**67**
MIDDLE EAST				
Abu Dhabi	9	4	13	14
Dubai	1	0	1	1
Egypt	39	11	50	39
Iran	0	0	0	0
Iraq	0	0	0	0
Jordan	1	0	0	1
Kuwait	11	0	11	16
Oman	53	0	53	41
Pakistan	19	0	19	17
Qatar	3	13	16	9
Saudi Arabia	65	11	76	75
Sudan	0	0	0	0
Syria	19	0	19	25
Yemen	16	0	16	15
Other	0	0	0	2
Subtotal	**235**	**39**	**274**	**255**
EUROPE				
Croatia	1	0	1	1
Denmark	0	2	2	0
France	1	0	1	0
Germany	4	1	5	4
Hungary	2	0	2	3
Italy	4	1	5	5
Netherlands	0	2	2	3
Norway	0	19	19	15
Poland	2	0	2	2
Romania	2	1	3	2
Turkey	5	0	5	4
UK	2	20	22	22
Other	8	0	8	4
Subtotal	**31**	**46**	**77**	**65**
Total	**2,852**	**355**	**3,207**	**3,125**

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	202	1.72
Caribbean	Houston	Resid.	380	281	2.67
Caribbean	Houston	Resid.	500	279	2.65
N. Europe	New York	Dist.	200	330	4.51
N. Europe	Houston	Crude	400	242	4.89
W. Africa	Houston	Crude	910	261	5.79
Persian Gulf	Houston	Crude	1,900	171	7.05
W. Africa	N. Europe	Crude	910	246	4.05
Persian Gulf	N. Europe	Crude	1,900	176	5.26
Persian Gulf	Japan	Crude	1,750	76	1.85

*Dec. 2007 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

Waterborne Energy Inc. US LNG imports

Country	Jan. 2007	Dec. 2006	Jan. 2005	Change from a year ago, %
	MMcf			
Algeria	2,521	0	2,988	–15.6
Brunei	0	0	0	—
Malaysia	0	0	0	—
Nigeria	5,325	3,082	3,028	—
Oman	0	0	0	—
Qatar	0	0	0	—
Trinidad and Tobago	36,792	36,718	30,480	20.7
Others	8,803	11,440	2,970	196.4
Total	**53,441**	**51,240**	**39,466**	**35.4**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
NOTE: No new data at presstime.

Propane prices

	Nov. 2007	Dec. 2007	Nov. 2006	Dec. 2006
	¢/gal			
Mont Belvieu	155.64	152.95	95.38	96.63
Conway	151.67	151.69	95.05	94.42
Northwest Europe	168.75	175.08	94.50	98.81

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					
Dec. 2007						
Product revenues	102.72	99.72	99.38	105.12	102.25	98.76
Feedstock costs	–92.28	–94.48	–82.48	–84.18	–92.35	–94.51
Gross margin	10.44	5.24	16.90	20.94	9.90	4.25
Fixed costs	–2.07	–2.39	–2.33	–2.72	–2.33	–1.81
Variable costs	–2.09	–1.39	–1.86	–3.17	–3.37	–1.02
Cash operating margin	**6.28**	**1.46**	**12.71**	**15.05**	**4.20**	**1.42**
Nov. 2007	9.33	4.23	16.35	16.23	8.07	2.63
YTD avg.	12.39	6.43	18.58	20.85	6.12	2.26
2006 avg.	12.49	6.01	14.91	23.73	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

Nov. 2007	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	313.27	291.92	334.01	314.06
Taxes	57.70	38.40	62.02	51.99
Wholesale price	244.26	241.33	261.62	247.43
Spot price	233.45	228.98	250.34	233.55
Retail margin	11.16	12.19	10.37	14.64
Wholesale margin	10.81	12.35	11.28	13.88
Gross marketing margin	**21.97**	**24.54**	**21.65**	**28.52**
Oct. 2007	26.01	20.36	11.64	24.93
YTD avg.	26.75	22.41	18.46	30.22
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38

*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.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Dec. 2007			
Product revenues	70.34	112.51	132.69
Feedstock costs	–43.89	–87.00	–120.60
Gross margin	26.45	25.51	12.09
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.25	–6.19	–8.33
Cash operating margin	**15.82**	**12.96**	**–3.43**
Nov. 2007	16.12	11.19	–8.91
YTD avg.	14.41	14.08	–7.43
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

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

Dec. 2007	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	6.82	5.79
Liquids	1.62	4.50
Gas purchase cost	7.59	7.78
Operating costs	0.07	0.15
Cash operating margin	**0.78**	**2.36**
Nov. 2007	0.79	2.61
YTD avg.	0.44	1.48
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment, % of liquids	50%	46%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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Condensate coming into its own

Condensate, one of the two groups defined as Natural Gas Liquids (NGLs), is finally coming of age in world trade, marketing, refining and petrochemicals. Condensate sales are moving from a niche marketing specialty to a mainstream segment of crude and products trade, and nowhere is this more evident than in the Mideast Gulf and Asia Pacific.

This report explains how the protean nature of condensate allows it to be used in a wide range of sectors: as a refinery slate component; in specialized distillation towers called condensate splitters; in direct feed to ethylene crackers; in gasoline blending and as a substitute for gas in turbine power generation. It can be defined as a base material, a blending component, a feedstock or a boiler feed.

See website for Table of Contents and sample tables, charts and graphs.

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Import arguments backfire against US oil producers

Arguments aimed at cutting US oil imports do producers more harm than good in Washington, DC. The industry should try a different approach.

Reducing oil imports is a legitimate goal. For the US economy, domestically produced oil—with all the incomes and tax payments it represents—surely beats the imported kind.

Import worry just doesn't work as an argument for policies essential to the expansion of US production.

In fact, it regularly succeeds as an argument to forget about expanding production and to quit using oil altogether—a popular fantasy with inexplicably strong influence over policy-making.

Consider the House Select Committee on Energy Independence and Global Warming.

The group's web site disparages oil imports for the usual reasons—funding of terrorists, profits for totalitarian regimes, intensifying competition for petroleum resources.

And, typically, it neglects to mention the economic goodness that the US forgoes with however much oil it imports instead of producing in off-limits areas such as 85% of the Outer Continental Shelf and the Arctic National Wildlife Refuge coastal plain.

If imports are so bad, why doesn't the US open the closed areas to boost domestic production?

According to the committee, it can't. The web site ludicrously compares US oil reserves (12th highest in the world) with total Middle Eastern reserves and implies that US production (third highest in the world) can't increase—although it did so last year.

The committee further characterizes the potential of ANWR—the coastal plain resource of which the US Geological Society estimates at 11.6-31.5 billion bbl of oil in place—as "a drop in the bucket in reducing the amount of imported oil."

It's no surprise that an outfit with this sense of proportion should think conservation and alternative energy by themselves can meet all US energy needs. They can't. Yet the view prevails. The US has a new energy law that boosts alternative energy sources and tinkers with consumption but says nothing about leasing of ANWR or locked-up expanses of the OCS.

The industry needs a new argument—maybe something that relates oil supply to a public concern less abstract than imports, like price.

(Online Jan. 11, 2008; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Recession worries trip up oil rally

Tight fundamentals, difficult geopolitics, and fears that an economic recession will reduce demand continue to worry energy markets.

After falling three consecutive sessions amid continued signs of a slowing economy, crude futures prices rebounded somewhat Jan. 8 when Nigeria's most powerful rebel force, the Movement for the Emancipation of the Niger Delta, reiterated its objective of halting 2 million b/d of crude exports from that country.

However, crude prices fell again in volatile trading Jan. 9-11 as traders shrugged off an eighth consecutive week of declining inventories and worried instead that a possible recession would diminish demand. The Energy Information Administration said commercial US inventories plunged 6.8 million bbl to 282.8 million bbl in the week ended Jan. 4, well below the Wall Street consensus of a 1.1 million bbl decline. Gasoline stocks jumped by 5.3 million bbl to 213.1 million bbl during the same week, the single largest increase since December 2006. Distillate fuel inventories increased by 1.5 million bbl to 128.7 million bbl. US imports of crude declined by 203,000 b/d to 9.8 million b/d during that same week. However, the input of crude into US refineries increased by 389,000 b/d to 15.8 million b/d, with refinery operations increasing to 91.3% of capacity. Gasoline production increased to 9.1 million b/d while distillate fuel production rose to 4.5 million b/d (OGJ Online, Jan. 9, 2008).

A suggestion by Federal Reserve Chairman Ben Bernanke that more "substantive" reductions of US interest rates may be pending helped slow the fall of crude prices on Jan. 10.

Crude futures prices increased more than $10/bbl in December to $100/bbl during the first trading session of 2008. But in early January, prices moved in a $7/bbl band below this milestone. "Further advances have been resisted by weak US economic data and forecasts of mild weather, both of which point to weaker US oil demand," said analysts at KBC Process Technology Ltd. in England.

"The rally in crude oil continues to stumble due to concerns over a US recession," said analysts in the Houston office of Raymond James & Associates Inc. "However, several data points help support the underlying bullish story. Specifically, US crude inventories continue to fall. Crude inventories have now fallen 22 of the last 27 weeks. Also helping to put a floor underneath crude prices is news that China has announced a freeze on gasoline price increases. This price freeze should help ensure that Asian demand for crude and refined products will remain strong," Raymond James analysts said.

Adam Sieminski, chief energy economist, Deutsche Bank AG, New York, said, "Demand remains relatively unresponsive to higher energy prices due to the growth in real incomes. Prices could be impacted by a global slowdown in gross domestic product, but a worldwide recession does not seem likely." Deutsche Bank now expects West Texas Intermediate and North Sea Brent nominal prices to average $75/bbl in 2010 and $80/bbl in 2012-13, compared with prior "midcycle" estimates nearer $65/bbl. US natural gas prices are forecast to average $8.75/MMbtu.

China, US drivers

Sieminski said China and US monetary policy should remain the key drivers of commodity markets during 2008. He predicted, "The strength in underlying gross domestic product and income growth across China will remain a major factor supporting commodity prices over the next few years. Indeed, the steady increase in Chinese GDP per capita since 1995 is remarkably similar to the improvement in living standards that unfolded in South Korea and Taiwan from 1980."

Furthermore, Sieminski said 55% of China's total population should be in urban areas by 2020, similar to the current urbanization ratio of Malaysia and the Philippines. "Since per capita energy consumption in urban areas is 3.5 times more than that in rural areas, the urbanization trend is generating a sustained period of strong energy demand," Sieminski said.

He said, "We believe the run-up in oil prices during the fourth quarter of 2007 goes beyond what can be explained by the decline in the US dollar and the level of global growth. However, refinery capacity, oil production constraints, and geopolitical issues continue to play a very important role in boosting prices. We believe it will require some normalizing of these factors to achieve our average crude oil price forecast of $85/bbl."

Sieminski said, "We expect [natural gas] prices will eventually benefit from inadequate capacity additions from proposed coal projects and wind power, which are required to meet electricity generation needs."

(Online Jan. 14, 2008; author's e-mail: samf@ogjonline.com)