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Midyear Forecast

Model framework can aid decision on gulf redevelopment

BP evaluates, develops North Slope reservoir

Changing feed pushes revamp of plant membrane system

Plans to add storage on US gulf could lead to overbuild


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START WITH THE RIGHT QUESTIONS
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July 14, 2008
Volume 106.26

Midyear Forecast

Regular Features

Cover

Moved to Alaminos Canyon in the Gulf of Mexico, this Noble semisubmersible drilling rig now operates in ultradeep water at the future home of the Shell-operated Perdido Regional Development spar. First production of oil and gas from Perdido is expected around the turn of the decade. In its midyear forecast, OGJ looks at the 2008 US market for oil, gas, and other energy sources, as well as worldwide oil supply and demand. Photo from Shell.

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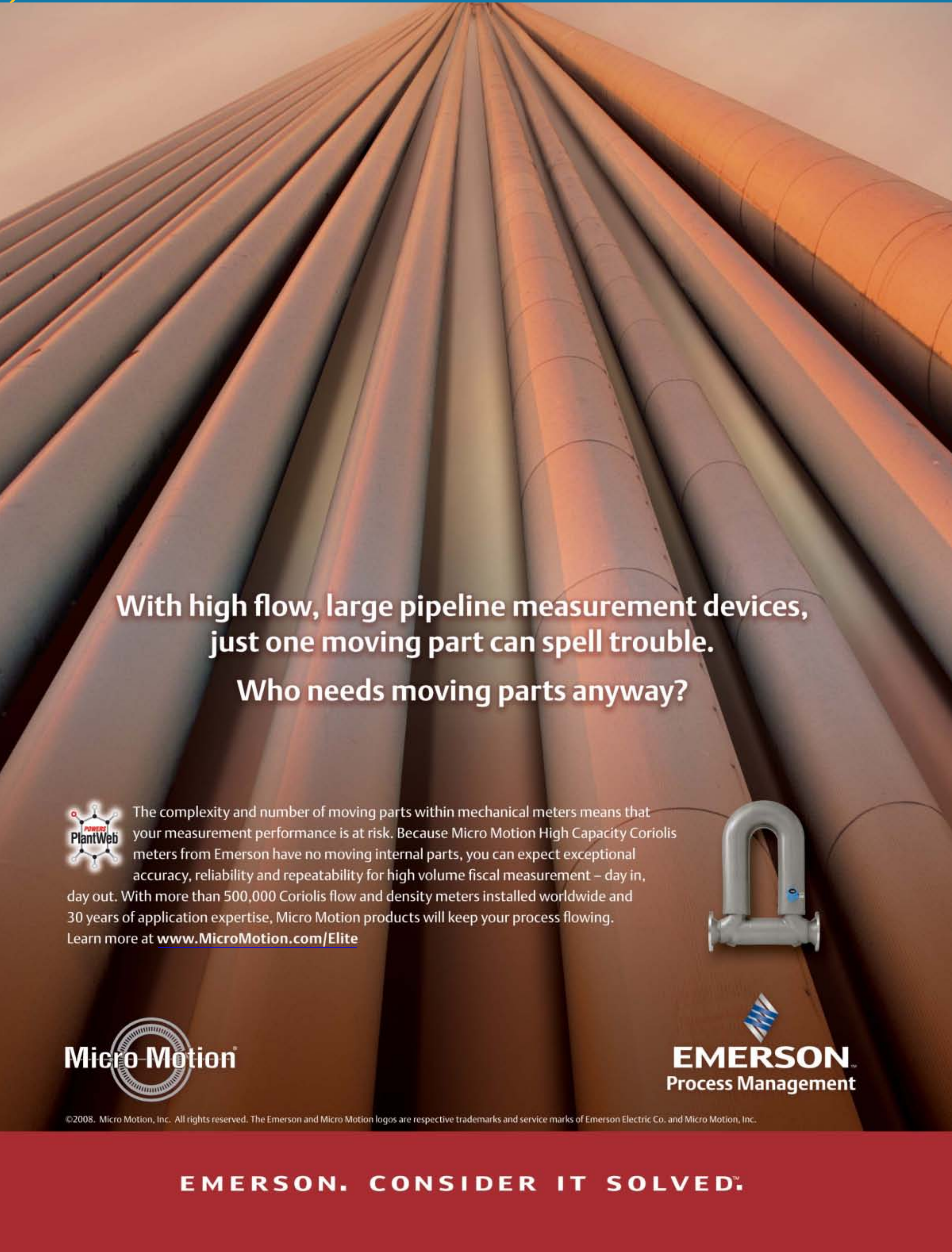
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OGJ Newsletter

July 14, 2008

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General Interest — *Quick Takes*

Oil & Gas UK outlines UKCS production challenges

Operators on the UK Continental Shelf (UKCS) spent £4.9 billion on developing new reserves in 2007 compared with £5.5 billion spent a year ago, according to an economic report produced by trade association Oil & Gas UK.

The decline in spending is worrisome because rising exploration and production costs mean that capital is only one-third as efficient as 5 years ago, which threatens bringing on new oil and gas production.

OGUK said the industry required significant investment over and above the £21 billion planned by companies to produce 9.8 billion boe over the next 5 years. The association believes that as much as 25 billion bbl could be recovered.

OGUK Chief Executive Malcolm Webb said, "Whilst realizing this goal will require massive further investment from the industry, at $100/bbl, it is worth $1.5 trillion to the British economy and this is a prize which the country should not contemplate losing."

The trade association has called on the government to offer tax incentives to attract investment in the mature province that produced 2.8 million boe/d in 2007. Indigenous production dropped by 4% in 2007 and is forecast to fall to 2.6-2.7 million in 2008 as several large projects reach full production. On current trends, production decline is expected to average 5% over the next 5 years.

Last year, the UK met 75% of its gas needs through domestic production and was self-sufficient in oil.

Carbon trading scheme advocated for Australia

Australia should introduce a carbon trading scheme as soon as possible, according to a draft report on climate change policy handed to the Australian government.

The commissioned report, written by economist Ross Garnaut, signals the start of efforts by the new Labor government in Canberra to cut carbon emissions. It recommends a broad emissions trading scheme across industries.

Although the 600-page report stopped short of placing any hard prices on carbon omissions (and thus not quantifying the true economic impact), it did advocate that transport fuels should be included in such a scheme. It also declared that energy costs will rise and coal-powered electricity generation would not be given any compensation for having to pay a carbon tax.

However, Garnaut said it would be in Australia's best interest to learn as soon as possible whether there can be a low-emissions future for coal, and to support rapid deployment of commercially promising technologies. He suggested that $3 billion (Aus.)/year be spent on developing low emissions technology and that Australia should strive to become a market leader in this work.

Garnaut said he supports the phase out of mandatory emissions targets once a trading scheme is put in place. The report is one of a number of inputs likely to shape the federal government's policy decisions in response to climate change.

Brazil to update oil law in wake of discoveries

Brazil's ministry of mines and energy has created a new working group that will aim to update the country's existing oil law, according to a senior government official.

"This group is studying the legislation of several countries, especially those which have a monopoly, and we are going to make a proposal to change the current law," said Mines and Energy Minister Edison Lobao.

The minister said every country changes the rules whenever new discoveries are made and that "Brazil can't be different." However, he acknowledged that there are interests intent on maintaining "the status quo."

Lobao, who said the changes are in the interests of the Brazilian people, was apparently referring to criticism of the proposed changes voiced by Petrobras Chief Executive Jose Sergio Gabrielli.

Noting that 60% of Petrobras's capital is private, while only 40% is held by the government, Lobao said Gabrielli represents a private company and, as such, is fighting for Petrobras's interests.

Lobao also gave assurances that the recently proposed creation of a new company to manage subsalt oil reserves will not result in a breach of existing contracts.

"This is an initial idea but, in my view, all contracts will have to be maintained," he said. "What we seek is a new formula."

It was reported recently that Lobao plans to propose to President Luiz Inacio Lula da Silva the creation of a new state-run firm that would manage oil discoveries made in recent months in the subsalt layer of the Santos basin (OGJ Online, June 30, 2008). ✦

Exploration & Development — *Quick Takes*

Husky presses work in basins off South China

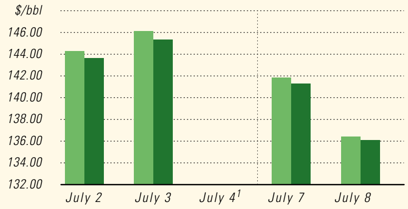
Husky Energy Inc., Calgary, has signed on for its eighth block off South China and plans to begin delineating its Liwan 3-1 deepwater gas discovery later this year.

Husky signed a contract with China National Offshore Oil Corp. for the 1,777 sq km Block 63/05 in the Qiongdongnan basin 100 km southeast of Hainan Island. The block is a similar distance southwest of Block 29/26, where Husky Energy plans to start delineation drilling in the third quarter of 2008 at its Liwan 3-1 discovery.

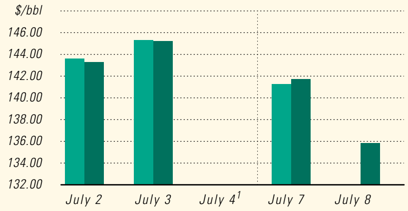
Liwan 3-1, in 1,300 m of water in the southwestern Pearl River Mouth basin, is the deepest water well drilled off China (OGJ, Mar.

Industry Scoreboard

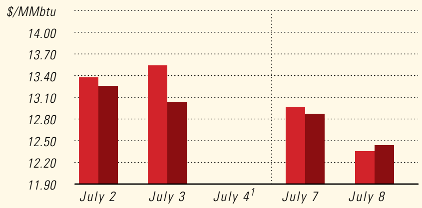
IPE BRENT / NYMEX LIGHT SWEET CRUDE



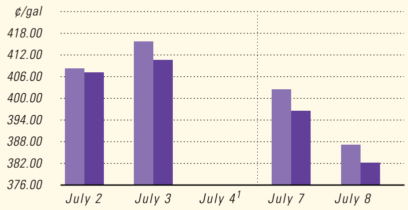
WTI CUSHING / BRENT SPOT



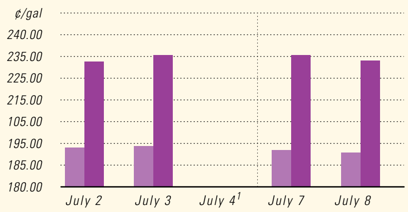
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



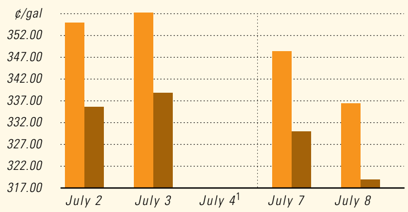
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available [2]Reformulated gasoline blendstock for oxygen blending. [3]Non-oxygenated regular unleaded.

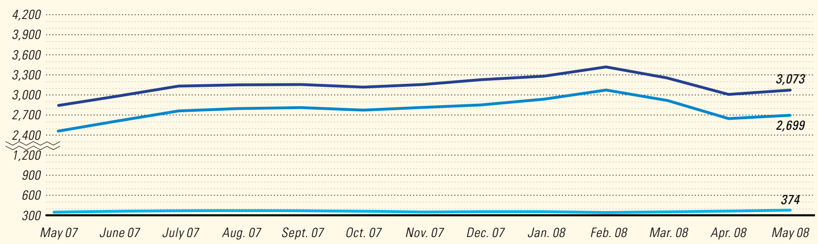
US INDUSTRY SCOREBOARD — 7/14

Latest week 6/27	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	9,338	9,504	–1.7	9,101	9,204	–1.1
Distillate	4,106	4,125	–0.5	4,175	4,265	–2.1
Jet fuel	1,598	1,656	–3.5	1,563	1,620	–3.5
Residual	587	734	–20.0	646	775	–16.6
Other products	4,713	4,711	—	4,832	4,844	–0.3
TOTAL DEMAND	20,342	20,730	–1.9	20,163	20,709	–2.6
Supply, 1,000 b/d						
Crude production	5,126	5,146	–0.4	5,113	5,188	–1.4
NGL production[2]	2,210	2,331	–5.2	2,272	2,349	–3.3
Crude imports	10,092	10,005	0.9	9,768	10,020	–2.5
Product imports	3,341	3,543	–5.7	3,253	3,540	–8.1
Other supply[3]	1,385	1,422	–2.6	1,413	975	44.9
TOTAL SUPPLY	22,154	22,447	–1.3	21,819	22,072	–1.1
Refining, 1,000 b/d						
Crude runs to stills	14,841	15,246	–2.7	14,841	14,989	–1.0
Input to crude stills	15,056	15,445	–2.5	15,056	15,305	–1.6
% utilization	86.0	88.5	—	86.0	87.7	—

Latest week 6/27	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	299,776	301,758	–1,982	354,042	–54,266	–15.3
Motor gasoline	210,857	208,757	2,100	204,433	6,424	3.1
Distillate	120,685	119,421	1,264	121,610	–925	–0.8
Jet fuel-kerosine	39,633	40,500	–867	40,619	–986	–2.4
Residual	40,000	39,253	747	34,845	5,155	14.8
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	19.5	19.6	–0.5	23.1	–15.6	
Motor gasoline	22.6	22.5	0.4	21.4	5.6	
Distillate	29.4	29.4	—	29.4	—	
Propane	39.8	38.9	2.3	45.2	–11.9	
Futures prices[5] **7/4**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	142.46	137.63	4.83	69.25	73.21	105.7
Natural gas, $/MMbtu	13.46	13.05	0.40	6.83	6.63	97.0

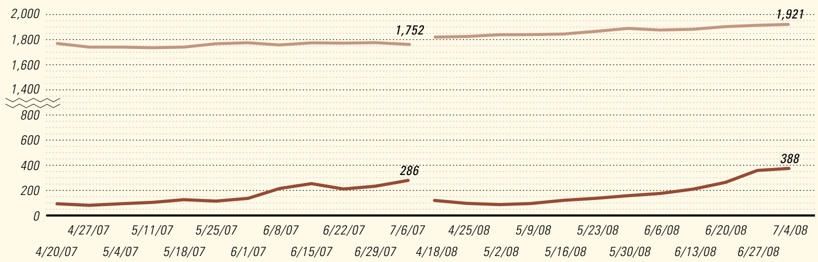
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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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26, 2007, p. 39). The South China Sea discovery well cut 56 m of net gas pay averaging 20% porosity in two zones on a structure with 60 sq km of closure.

The Liwan discovery well was drilled on 2D seismic, and Husky has now shot 925 sq km of 3D seismic across Block 29/26 and adjacent 29/06.

Husky also shot 750 sq km of 3D seismic on Block 35/18 in the Yinggehai basin west of Hainan Island and expects to drill exploration wells in 2009-10 on Yinggehai blocks 35/18 and 50/14 and Liwan blocks 29/06 and 29/26.

Seismic starts in central BC's Nechako basin

Industry-led, nonprofit Geoscience BC has launched a 350 line-km 2D seismic survey southwest of Prince George in British Columbia's nonproducing Nechako basin.

The Vibroseis survey on existing forest roads is the first seismic shot in the basin since the early 1980s.

The survey area is largely contained in the Nazko First Nation's Traditional Territory, and seismic contractor CGGVeritas is providing training and employment opportunities to Nazko citizens.

The area west of Quesnel is also in the heart of the mountain pine beetle affected area of interior British Columbia, said British Columbia Energy Minister Richard Neufeld.

"Successful oil and gas development in the Nechako basin has the potential to help offset the economic impacts of the mountain pine beetle infestation," Neufeld said.

The Northern Development Initiative Trust Pine Beetle Recovery Account is providing $500,000 of the $2.5 million cost of the survey.

After Canadian Hunter Exploration Ltd. shot 1,300 line-km of 2D seismic in the basin 25 years ago, five wells were drilled but hydrocarbon exploration ceased shortly after. The basin's oil and gas potential is still not well understood, said 'Lyn Anglin, president and chief executive officer of Geoscience BC.

OGDC finds gas with Dhodak well in Pakistan

Pakistan Oil & Gas Development Corp. (OGDC) reported a natural gas discovery in its Dhodak Deep No. 1 exploration well drilled in Dera Ghazi Khan district in Punjab province under the Dhodak drilling and production license.

The well, which was spudded June 30, was drilled to a target depth of 4,150 m.

Based on open-hole logs and drilling data, the selective interval of 85 m in Chiltan limestone formation was tested. After stimulation, it produced 5.5 MMcfd of gas through a ½-in. choke. Wellhead pressure was recorded as 1,500 psi, while water production was recorded as 60 b/d.

Sterling Energy spuds Iris Marin well off Gabon

Sterling Energy PLC spudded its Iris Charlie Marin-1 exploration well (ICM-1) in the Iris Marin production-sharing contract area off Gabon.

Hercules Offshore's Hercules 156 jack up rig began drilling July 5 in 25 m of water 12 km southwest of the Gamba field and is expected to reach its target depth later this month. The prospect is estimated to hold reserves of 20-40 million bbl in the Gamba sandstone formation.

Sterling has 32% interest in the licence following a recent farmout to Addax Petroleum. About 18% of Sterling's costs in the well are being paid by Addax Petroleum. ✦

Drilling & Production — *Quick Takes*

Neptune starts oil, gas production in gulf

BHP Billiton Ltd. and its partners in the Neptune oil and gas development in the deepwater Gulf of Mexico reported the start of production. Neptune, which lies 120 miles off Louisiana, is being developed using a tension-leg platform installed on Green Canyon Block 613 in 4,250 ft of water.

The TLP facility's design capacity is 50,000 b/d of oil and 50 MMcfd of gas. The facility had recently undergone remediation to strengthen components inside the hull's pontoons, Neptune partner Marathon Oil Corp. said.

Neptune field comprises five blocks: Atwater Valley blocks 573, 574, 575, 617, and 618. Water depths range 4,200-6,500 ft. Crude oil from Neptune is transported via the Caesar pipeline, while natural gas is exported via the Cleopatra pipeline.

SBM Atlantia Inc. installed the TLP's 5,900-ton hull last year (OGJ, Aug. 6, 2007, Newsletter).

Field development includes six initial subsea wells tied back to the TLP. Further development wells are expected to be drilled after interpretation of new seismic data, which will be obtained in this year's second half.

Neptune partners are operator BHP Billiton Ltd. 35%, Marathon 30%, Woodside Energy (USA) Inc. 20%, and Repsol-YPF SA unit Maxus (US) Exploration Co. 15%.

Bualuang oil field off Thailand set to produce

Soco International PLC, a partner in Bualuang field in the Gulf of Thailand, said oil production from the field would commence this month. Salamander Energy PLC operates the field, which was first discovered in 1993 on Block B8/38.

Thai Energy Ministry officials indicated that output from the field of as much as 10,000 b/d could be expected.

The field's proved oil reserves were recently upgraded to 11 million bbl from 7.2 million bbl, with probable and possible reserves lifted to 20 million bbl (OGJ, June 6, 2008, Newsletter).

Rubicon Vantage, the floating production, storage, and offloading vessel, was being hooked up to the wells.

Six development wells were drilled in the field, encountering 27° oil, a better-quality reservoir than forecast.

Salamander holds a 60% interest in Block B8/38, and Soco has a 40% stake.

Oxy invests in CO_2 source for Permian basin EOR

Occidental Petroleum Corp. with its agreement with SandRidge

Energy plans to increase substantially the amount of carbon dioxide available in the Permian basin for use in enhanced oil recovery projects.

The CO_2 will come from Oxy's planned gas processing plant to be built in Pecos County, Tex.

Oxy expects the additional CO_2 will allow its projects in the area to increase production by at least 50,000 bo/d in the next 5 years.

Oxy Chairman and Chief Executive Officer Ray R. Irani said the project will provide at least 3.5 tcf of CO_2 for Oxy's long-term use in EOR projects and develop about 500 million bbl of oil reserves from currently owned assets at an attractive cost.

Oxy will own and operate the new facilities and will invest about $1.1 billion in their development.

The planned gas processing plant has an expected 450 MMcfd of CO_2 takeaway capacity, and Oxy expects to receive another 50 MMcfd of CO_2 from existing SandRidge gas processing plants. The project also includes construction of a 160-mile pipeline from the plant, through McCamey, Tex., to the industry's CO_2 hub in Denver City, Tex.

The plant will process SandRidge's locally produced, high CO_2-content natural gas.

Oxy says it is the largest producer in the Permian basin with about a 16% net share of total regional production. It produces about 200,000 boe/d and at yearend 2007, its Permian basin properties contained proved reserves of about 1.2 billion boe.

Subject to approvals, Oxy expects the new gas plant and pipeline in 2011 to start operations and commence CO_2 deliveries to its existing CO_2 EOR operations.

In 2007, the Permian basin received about 1.371 bcfd of CO_2 for use in EOR projects (OGJ, Apr. 21, 2008, p. 45).

StatoilHydro improves Gullfaks oil recovery factor

StatoilHydro produced an extra 60 million bbl of oil from Gullfaks field in the Norwegian North Sea as it has improved the recovery factor to more than 60%.

Reidar Helland, head of petroleum technology at StatoilHydro, said during a presentation at the World Petroleum Congress that 4D seismic surveys are a key mechanism to locating hidden barrels of oil that equate to more than a year's production from the field.

However, StatoilHydro wants to improve the rate of recovery at Gullfaks to 70% and sustain production to 2030, which Helland described as a "challenging ambition."

The company has drilled 17 wells on Gullfaks based on 4D seismic data—wells that would not have been drilled without this technology. "Oil has been struck in all of the wells. In other words, an excellent accuracy. This experience clearly shows the importance of employing new technology," Helland said.

Shell continues operations in Ogoniland

Shell Petroleum Development Co. (SPDC) has not been ordered to leave its operations in Ogoniland in Rivers State, although Nigerian President Umaru Yar'Adua said another operator would replace Shell by yearend.

Yar'Adua said in June that trust between the Ogoni people and Shell has badly deteriorated and a new operator would be assigned. But Mutiu Sunmonu, managing director of the Shell subsidiary, told reporters in Port Harcourt the company still holds a 30% stake in its oil wells in the area.

Sumonu said company officials learned of the president's remarks via the media. "We are yet to get any letter or official directive on the matter as [of] today. The federal government has not formally notified us. There has not been a formal letter. We have heard and discussed it. What the president said is headline statement, [of] which details are not available," he said.

The government set December as the new deadline to end gas-flaring in the Niger Delta, and Sunmonu said the company would have to spend $5 billion to meet this target. SPDC missed previous gas flaring deadlines because its joint venture partner, Nigeria National Petroleum Corp., failed to contribute its share of funding to set up gas gathering infrastructure. So far SPDC has spent $3 billion in "commissioning facilities to gather and process gas."

Sunmonu said the security problem in the Delta would determine whether the firm could meet the government's new deadline.

SPDC agreed to loan the federal government $1.3 billion to advance its stalled projects in the Niger Delta. Both parties signed only a head agreement, Sumonu said. The final agreement is still being negotiated. Total SA and ExxonMobil Corp. agreed to loan the government $6.1 billion to cover the funding gap.

Sumonu denied that SPDC laid off more than 2,000 employees due to soaring exploration and production costs and reduced output because of repeated attacks on its operations in the Niger Delta. He said a review of Shell operations is still under way. ✦

Processing — *Quick Takes*

IRS issues regs to encourage refinery expansions

The US Internal Revenue Service has issued temporary regulations and a notice of proposed rulemaking (NOPR) to encourage expansion of existing US refineries and construction of new plants as mandated by the 2005 Energy Policy Act (EPACT).

The temporary regulations amend Section 179C of the federal income tax code, which was added when EPACT became law. They define "qualified refinery property" and are designed to assist refiners in determining costs that may be expensed under the provision, the US Department of Treasury division said on July 8.

An installation located within the US that processes liquid fuel from oil or other qualified fuel is considered a qualified refinery under the temporary regulations, which the IRS has proposed adopting as a rulemaking. Not eligible are refinery properties that are primarily topping plants, asphalt plants, lubricant facilities, crude or product terminals, or blending facilities. Nor is refinery property built solely to comply with consent decrees or projects mandated by federal, state, or local governments.

Section 179C allows refiners to deduct 50% of the cost of any qualified refinery property that goes into service between Aug. 8, 2005, and Jan. 1, 2012, according to the notice. Remaining qualified expenditures are generally recovered under Section 179B and Section 168 where applicable, it indicated. All properly capitalized costs can be included, it said.

The IRS will take comments on its proposed rulemaking through Oct. 7. It also plans to hold a public hearing Nov. 20 and will accept outlines of topics to be discussed there through Oct. 14.

StatoilHydro starts Mongstad refinery upgrade

StatoilHydro has let an engineering and procurement contract to M.W. Kellogg Ltd. to upgrade the coker unit at its 186,000 b/d Mongstad refinery near Bergen, Norway.

"The project will improve the working environment and safety of the operators on the coker unit by automating processes to improve safety, performance, and reliability," said Kellogg parent company KBR. The value of the contract was not disclosed.

The coker unit will be closed in 2009 while the revamp is carried out along with a scheduled refinery turnaround period in April 2010, with completion scheduled for the middle of 2010. Project work will be performed at Kellogg's main office, along with collocated StatoilHydro representatives, in Greenford, West London. ✦

Transportation — *Quick Takes*

Alaska looks toward intrastate gas line

Alaska has formed a public-private partnership to build an intrastate gas pipeline to serve south-central and interior Alaska.

The system would begin service in 2013 with a capacity of 460 MMcfd of gas—about twice current demand. The supply would mainly come from undiscovered supplies in Cook Inlet, interior basins along the pipeline, and the North Slope foothills, officials said.

Construction would start at Cook Inlet and progress north along the Richardson Highway for about 400 miles, reaching Fairbanks and interior Alaska by 2013.

If sufficient supplies fail to materialize from the Cook Inlet and Copper River basins and exploration along the pipeline, a second phase would involve a leg to bring gas from the North Slope foothills.

If the second phase were not needed, the line could be connected to the pipeline planned to move North Slope gas to Canada and the Lower 48, officials said, when it is completed in 2018-20.

Forming the partnership were the Alaska Natural Gas Development Authority, Enstar Natural Gas Co., and the state, said Gov. Sarah Palin. She said specifics would be worked out this fall in time to be added to appropriations legislation in January 2009. Construction would start in 2011.

ExxonMobil to position Adriatic LNG terminal

ExxonMobil Corp. plans in August to move the gravity-based Adriatic LNG regasification terminal to the Adriatic Sea off Italy. Construction of the 6-million-tonne/year terminal is nearing completion, said Rex Tillerson, ExxonMobil chief executive.

It will be the world's first offshore gravity-based regasification terminal, with capacity to supply 10% of Europe's LNG needs.

The company has developed Q-Max technology with Qatar Petroleum that increases the LNG ship cargo capacity by 80%.

Tillerson said a global LNG market will supply increasing energy demand but he stressed that energy efficiency was crucial also because it extends the life of resources, reduces greenhouse-gas emissions and energy prices, and strengthens energy security.

ExxonMobil has invested more than $1.5 billion on energy efficiency since 2004, has budgeted $500 million on additional initiatives over the next few years, and will work with vehicle manufacturers to develop transportation technologies that can improve fuel economy and reduce emissions.

Fos oil terminal gets nod from port board

The Marseille Port Board approved construction of a seventh mooring berth for refined oil products at the Fos petroleum terminal.

The investment will amount to €22 million, in addition to the €32.7 million investment voted last November to build a sixth mooring berth alongside the quay. This will increase the receiving capacity of the Fos oil terminal to 21.5 million tons in 2011 from 6 million tons in 2006.

The latest expansion is dictated by the need to adapt the Fos terminal to the increasing storage capacity of the Fos Oil Depots (DPF) and creation of a new oil depot by OMM (Oiltanking-Mediaco), a joint venture of France's Mediaco and Germany's Oiltanking and subsidiary of Germany's Marquard and Bahls, the world's second leading terminal storage group.

The seventh mooring berth will accommodate 45,000-ton vessels 200 m long and will provide a 12 m water draught. It will be operational mid-2011.

Canadian oil pipeline capacity remains tight

Canadian oil pipeline systems need additional capacity soon to accommodate growing supply and provide greater market flexibility, according to Canada's National Energy Board.

"Capacity constraints on oil pipelines in Canada were evident in 2007," said NEB Vice-Chair Sheila Leggett. "While there was some spare capacity, periods of apportionment meant that some pipelines were at times not able to fully meet shipper demand."

The high capacity utilization is driven by growing oil sands production and continued strong demand in the US. Although some capacity will be added in 2008, tight conditions will likely exist for the remainder of the year, officials said in their annual report on the 45,000 km of oil, natural gas, and product pipelines regulated by the NEB.

Most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. Throughput for most gas pipelines declined in 2007 due to declining conventional gas supplies from the Western Canada Sedimentary Basin, growing demand within western Canada, and competition from other supply basins, particularly in the western US. ✦

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

JULY

AAPG/SPE/SEG Hedberg Conference, Casper, Wyo. (918) 560-2630, (918) 560-2678 (fax), e-mail: debbi@aapg.org, website: www.aapg.org. 14-18.

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

SPE Nigeria Annul International Conference & Exhibition, Abuja, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

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

International Petroleum Petrochemical Natural Gas Technology Equipment Exhibition, Shanghai, +86 21 55611008, +86 21 65282319 (fax), website: postmaster@aiexpo.com.cn, website: www.sippe.org.cn. 20-22.

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.

Deep Water India Summit, New Delhi, +31 (0)26 3653 444, +31 (0)26 3653 446 (fax), e-mail: workshops@energywise.nl, website: www.energywise.nl. 26-27.

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

Annual India Oil & Gas Review Symposium & International Exhibition, Mumbai, (0091-22) 40504900, ext. 225, (0091-22) 26367676 (fax), e-mail: oilasia@vsnl.com, website: www.oilasia.com. 1-2.

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.

Rice Global Engineering & Construction Forum, Houston,

(713) 552-1236, ext. 3, (713) 572-3089 (fax), website: www.forum.rice.edu. 9.

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.

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 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.

✦DGMK Future Feedstocks for Fuels & Chemicals Conference, Berlin, 040 639004 0. 040 639004 50 (fax), website: www.dgmk.de. Sept. 29-Oct. 1.

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

Calendar

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

GPA North Texas/NGS East Texas Red River Conference, Tyler, Tex., (713) 222-0852, (713) 222-0858 (fax), e-mail: tom.rommel@accessed.com, website: www.gasprocessors.com. 1-2.

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

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessor.com. 7.

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.

Middle East Plant Maintenance Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: d.michalski@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 13-15.

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

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 13-17.

Central and Eastern European Refining & Petrochemicals Roundtable, Warsaw, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-16.

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

Oil & Gas Transportation in the CIS & Caspian Region Conference, Moscow, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: j.golodnikova@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/cispipes10register.html. 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.

Petchem Arabia Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.verma@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 20-22.

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.

Biofuels Conference, Berlin, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 28-30.

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.

Arab Oil & Gas Show, Dubai, +971 4 3355001, +971 4 3355141 (fax), e-mail: info@icedxb.com, website: www.ogsonline.com. 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, +971 (0) 2 4444 909, +971 (0) 2 4444 383 (fax), e-mail: info@adipec.com, 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.

North African Oil and Gas Summit, Vienna, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: c.brown@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/nas3register.html. 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.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

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.

Annual Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 18-20.

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 Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 2-3.

Annual Refining & Petrochemicals in Russia and the CIS Countries Roundtable, Prague, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 2-4.

Downstream Asia Refining & Petrochemicals Conference, Singapore, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/dalregister.html. 3-4.

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.

Calendar

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.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

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.

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

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

2009

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.piipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

FEBRUARY

SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 2-4.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

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

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

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

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

APRIL

IADC Drilling HSE Middle East Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21-22.

MAY

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

IADC Environmental Conference & Exhibition, Stavanger, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21.

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

JUNE

AAPG Annual Meeting, Denver, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 7-10.

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

IADC World Drilling Conference & Exhibition, Dublin, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17-18.

AUGUST

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

SEPTEMBER

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

OCTOBER

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

Oil-price decline? Maybe

Marilyn Radler
Senior Editor-Economics

High oil prices are certainly putting downward pressure on demand in the US and in other countries where the market is allowed to work, as opposed to countries that have fuel subsidies in place for consumers. Some Asian governments, though, have recently removed or reduced their oil subsidies.

So, is widespread price-driven oil-demand destruction inevitable? And will prices fall?

Now that oil prices have reached record highs in both nominal and real terms, the International Energy Agency is looking at how these prices are affecting global economic growth and overall oil demand.

It is apparent that high prices are having an effect on demand, but it is important to look at how expensive oil has really become, IEA said in its June oil market report.

The agency finds that not only do global oil expenditures as a share of global gross domestic product remain lower than in the 1980s, but also oil intensity—the volume of oil required to produce a unit of GDP—today is half what it was in the early 1970s.

"At first glance, therefore, it would appear that the global economy is less vulnerable than in the recent past, even though oil prices have reached historically high levels. Yet to conclude that the current oil price rally is harmless would be misleading. Indeed, current oil prices will arguably have damaging and long-lasting economic consequences," IEA says.

Oil prices are fuelling inflation both inside and outside the Organization for Economic Cooperation and Development. For the poorest oil-importing countries, higher oil prices will have a dramatic effect on income and development levels.

Oil demand is already stagnating or declining in OECD countries and in most of the world's poorest countries. While some of the effects of high oil prices upon inflation, consumer spending, and growth are clear, the interactions are complex, the agency says.

IEA will continue an in-depth study of these issues and present the findings in its 2008 world energy outlook, due late this year.

Puzzling market

In his latest strategic brief, Michael Lynch of Strategic Energy and Economic Research Inc. observes that in spite of oil demand proving to be weak, with the macroeconomic news globally being very bearish, and with supply apparently growing—particularly in Iraq and Saudi Arabia—oil prices not only remain high but are setting records.

Lynch likens the current market to the one in 1997, when the Asian economic collapse weakened oil demand.

Despite terrible economic news in Asia and a currency meltdown in July 1997, oil prices continued to rise through September of that year, as markets focused on the dispute between Iraq and the UN over the oil-for-food program, and oil peaked on Oct. 3, 1997.

On Nov. 29, 1997, OPEC agreed to increase its production targets for the first time in 4 years, which led to an actual production rise of 500,000 b/d. The combination of weaker demand and greater supply eventually led to a huge inventory build and falling prices.

Slow to react

But it wasn't until late in the year that prices declined even moderately, and market reports from that period suggest that observers were unconvinced that prices would decline significantly, Lynch says.

The oil market could face a similar scenario in 2008, he says, if demand in the second half of this year is weak, as looks likely, and if supplies move higher as a result of an increase in output from Saudi Arabia, a ceasefire in Nigeria, and recovery in Iraqi production.

The scenario would be especially likely if demand weakness occurs in areas where the data is reported late, such as non-OECD Asia, because then inventories could build strongly before markets react, suppressing prices longer than otherwise, Lynch adds.

With the combination of Saudi and Iraqi oil surging, the possibility of a restoration of Nigerian production, as well as rising OECD production, a significant and growing surplus could occur.

Two factors will determine the extent of the inventory build, Lynch says—whether the oil goes to the US, where it would be reported earlier, and how quickly lower demand in non-OECD regions becomes apparent. "And ultimately, how quickly the Saudis respond by cutting production will influence how far (and how fast) prices drop," Lynch says. ✦

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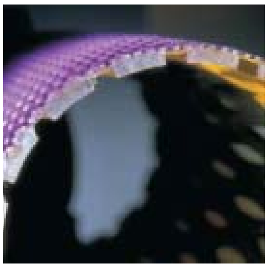

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E d i t o r i a l

Higher fuel costs loom

While recent increases in US gasoline and diesel fuel prices result mainly from a global surge in the price of crude oil, room must be reserved in any explanation for regulatory changes that have lifted the costs of fuel manufacture and distribution. At present, crude prices mask the effects of these changes. The costs, however, are firmly in place. They set floors below which the prices of oil products can't stay for long. And more of them are in prospect.

During the next few years, regulations will evolve on at least three fronts in ways that will keep upward pressure on the costs of vehicle fuels. The ethanol mandate will grow. The requirement for ultralow-sulfur diesel will expand, including into off-highway markets. And new federal standards for ozone pollution will move some number of regions toward, if not into, noncompliance.

Interacting effects

These developments interact. Ethanol, for example, aggravates ozone pollution in some areas. Requirements for the gasoline additive, set in the Energy Policy Act of 2005 and greatly increased in last year's Energy Independence and Security Act, are increasing in annual steps. The mandate this year is 9 billion gal, mostly from corn. Eventually it will reach 36 billion gal, 15 billion gal of which can come from corn.

The natural market for ethanol is reformulated gasoline, where the material has value as an oxygen and octane booster. Reformulated product, required in areas with chronic ozone pollution, accounts for about one third of US gasoline supply.

According to the Energy Policy Research Foundation Inc., Washington, DC, ethanol had saturated the reformulated gasoline market by the end of last year. To meet escalating mandates, it will have to be blended into growing amounts of conventional gasoline. The result will be increased tailpipe and evaporative emissions of ozone precursors—another push toward noncompliance with air-quality standards. An increase in the number of such nonattainment areas would expand the requirement for reformulated gasoline and further raise the costs of making gasoline.

Growth of the ethanol mandate also portends increased demand for diesel, the cost of making which jumped in response to requirements for sharply reduced sulfur content. Little ethanol moves via pipeline because of the substance's affinity for water and potential to cause stress corrosion cracking of steel. Most ethanol transport, therefore, occurs in trucks and rail cars.

While ethanol requirements, and therefore diesel-fueled transportation, expand, so will application of the ultralow-sulfur mandate. In 2010, refiners will lose their regulatory ability to produce as much as 20% of their highway diesel at an elevated sulfur concentration. In the same year, the ultralow-sulfur requirement will take in non-highway uses other than locomotives and marine engines. In 2012, those diesel users will enter the ultralow-sulfur realm. And in 2014, exemptions for small refiners will expire.

In terms of affected volumes, none of these steps will be nearly as large as the one taken in 2006 when the ultralow-sulfur requirement for highway diesel began taking effect. Each one nevertheless represents substitution of one grade of fuel with another notably more costly to make.

Other changes

Other changes with potential to raise fuel costs loom. The second phase of the Mobile Source Air Toxic program administered by the Environmental Protection Agency, for example, will begin taking effect in mid-2011. The program, which provides for the banking and trading of compliance credits, mainly affects benzene. It applies a content cap for reformulated gasoline but not for conventional fuel—a distinction with possible cost implications if requirements for the reformulated product grows.

And, despite federal efforts to suppress the proliferation of fuel specifications applied at state and local levels, the boutique fuel problem remains in place. Refiners still must deal with the reduced flexibility that comes from having to produce fuel to multiple sets of specifications.

With some exceptions, these and other regulations have improved the environmental performance of US vehicle fuels. They have, however, raised the costs of making, and ultimately the retail prices of, diesel and gasoline. More fuel changes are just a few years away. So are higher costs. ✦

Energy demand takes diverse paths in 2008

Marilyn Radler
Senior Editor-Economics

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While US energy demand this year will be limited by weak economic growth and improved fuel-use efficiency, China, Latin America, and the Middle East will sustain worldwide oil demand growth despite high global prices and keep pressure on supply.

The extent to which producers can respond to the need for more oil in the short run is inadequate to relieve prices.

US oil demand will contract this year, and demand for natural gas and coal will get a lift from increased power consumption. Hydroelectric power and other renewable sources of energy will also be in higher demand in the US, although they still represent a small share of the energy market.

Production of crude, condensate, and liquids in the US will climb faintly, but with demand waning, imports will decline. US gas production will also increase this year.

Worldwide outlook

Worldwide oil demand will increase 800,000 b/d this year, according to estimates by the International Energy Agency, and all of the growth will take place in countries outside the Organization for Economic Cooperation and Development.

Demand in the OECD will contract 500,000 b/d from last year, as North American consumption shrinks on economic weakness and demand in Europe and Asia/Pacific holds steady.

China, with demand rising to 8 million b/d from 7.5 million b/d last year, will lead demand growth outside the OECD. Meanwhile, IEA expects demand to rise 300,000 b/d in both Latin America and the Middle East.

Declining OECD oil output will be offset this year by a small increase in non-OECD oil production outside the Organization of Petroleum Exporting Countries, processing gain, and biofuels production. This will leave total non-OPEC supply at an average 50 million b/d for 2008.

OGJ forecasts that following first-quarter 2008 OPEC supply of 32.3 million b/d, oil output by the organization averaged 32.2 million b/d in the second quarter and will rise to average 32.4 million b/d in the second half of the year.

Although Saudi Arabia pledged last month to increase output, any gain will be negated by production declines in Nigeria brought about by militant attacks on production facilities and the possibility of production cuts in other OPEC countries.

With 5.1 million b/d of OPEC natural gas liquids, worldwide oil supply will average 87.4 million b/d this year, resulting in a stockbuild of 600,000 b/d.

Oil prices

"As oil prices rose to $50, $70, and $90/bbl, analysts often pointed out that these prices hadn't yet breached the all-time high in real, or inflation-adjusted, terms," said Stephen Brown, director of energy economics and microeconomic policy at the Federal Reserve Bank of Dallas. "That barrier finally fell in early March, when prices topped the real 1980 peak."

Escalating worldwide oil demand, propelled by climbing consumption in developing countries, strengthened competition for crude supplies. Limited spare crude production capacity combined with supply disruptions and declining output in some key exporting countries to strain the amount of available crude.

In addition, a weakening US dollar drew investment funds to oil and other commodities as a hedge against inflation. Geopolitical tensions, including the possibility of conflict between Israel and Iran, continued to add upward pressure to oil prices through the first half of 2008.

In March, the closing price of the front-month futures price of crude on the New York Mercantile Exchange surpassed $110/bbl. The futures price closed at another record high of $145.29/bbl on July 3. This compares to a closing price of $71.41/bbl a year earlier.

In June some countries, including India, Indonesia, Malaysia, Sri Lanka, and Taiwan, relaxed subsidies on fuels, which had shielded their consumers from the pain of high prices and blunted incentives to conserve. Easing subsidies might suppress demand this year but will have little, if any, impact on world prices.

Also in June the world's largest crude supplier, Saudi Arabia, announced plans to increase production. This news had little impact on prices, though, as the incremental supply not only reduced spare production capacity but also put a greater volume of heavy, less-desirable crude on the market.

Worldwide oil supply and demand

Table 1

	2007					2008				
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	Year
	Million b/d									
DEMAND										
OECD										
North America	25.7	25.4	25.5	25.5	25.5	24.8	25.0	25.2	25.2	25.0
Europe	15.2	14.9	15.4	15.6	15.3	15.1	15.1	15.4	15.5	15.3
Asia/Pacific	8.8	7.8	7.8	8.6	8.3	8.8	7.9	7.9	8.7	8.3
Total OECD	**49.7**	**48.2**	**48.7**	**49.8**	**49.1**	**48.7**	**48.0**	**48.4**	**49.4**	**48.6**
Non–OECD										
FSU	4.1	3.9	4.2	4.3	4.1	4.1	4.0	4.3	4.4	4.2
Europe	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.7	0.8	0.8
China	7.3	7.7	7.5	7.6	7.5	7.9	8.1	7.9	8.0	8.0
Other Asia	9.3	9.4	9.1	9.4	9.3	9.6	9.5	9.1	9.4	9.4
Latin America	5.4	5.6	5.7	5.7	5.6	5.7	5.8	6.0	6.0	5.9
Middle East	6.4	6.5	6.7	6.4	6.5	6.7	6.8	7.1	6.8	6.8
Africa	3.1	3.1	3.0	3.1	3.1	3.1	3.1	3.0	3.2	3.1
Total Non–OECD	**36.4**	**36.9**	**36.9**	**37.3**	**36.9**	**37.9**	**38.0**	**38.1**	**38.6**	**38.1**
TOTAL DEMAND	**86.1**	**85.1**	**85.6**	**87.1**	**86.0**	**86.6**	**86.1**	**86.5**	**87.9**	**86.8**
Supply										
OECD										
North America	14.4	14.4	14.2	14.1	14.3	14.2	13.9	14.1	14.4	14.1
Europe	5.2	4.9	4.7	5.0	5.0	4.9	4.5	4.3	4.6	4.6
Asia	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.8	0.7
Total OECD	**20.2**	**19.9**	**19.5**	**19.8**	**19.8**	**19.7**	**19.1**	**19.1**	**19.9**	**19.4**
Non–OECD										
FSU	12.8	12.7	12.8	12.8	12.8	12.8	12.9	13.1	13.5	13.1
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	3.7	3.7	3.8	3.8	3.9	3.9	3.8
Other Asia	2.7	2.7	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.7
Latin America	4.4	4.4	4.3	4.2	4.3	3.9	4.0	4.1	4.2	4.1
Middle East	1.7	1.7	1.7	1.6	1.7	1.6	1.6	1.6	1.6	1.6
Africa	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6
Total Non–OECD	**27.9**	**27.8**	**27.7**	**27.7**	**27.8**	**27.5**	**27.6**	**28.1**	**28.6**	**28.0**
Processing gain	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.1
Other biofuels	0.3	0.3	0.3	0.4	0.3	0.4	0.5	0.5	0.6	0.5
Total Non–OPEC	**50.4**	**50.2**	**49.7**	**49.9**	**50.0**	**49.7**	**49.3**	**49.9**	**51.2**	**50.0**
OPEC[1]										
Crude	30.3	30.2	30.6	31.5	30.7	32.3	32.2	32.4	32.4	32.3
NGL	4.8	4.8	4.8	4.9	4.8	4.9	5.0	5.2	5.4	5.1
Total OPEC	**35.1**	**34.9**	**35.4**	**36.4**	**35.5**	**37.3**	**37.2**	**37.6**	**37.8**	**37.4**
Total SUPPLY	**85.5**	**85.1**	**85.1**	**86.4**	**85.5**	**87.0**	**86.5**	**87.5**	**89.0**	**87.4**
Stock change	(0.6)	—	(0.5)	(0.8)	(0.4)	0.4	0.4	1.0	1.1	0.6

[1]Includes Ecuador beginning Dec. 2007. Totals may not add due to rounding.
Source: International Energy Agency; OGJ estimates for OPEC 2nd, 3rd, and 4th quarter 2008 crude supply

OGJ forecasts that the 2008 US wellhead price of crude will average $110/bbl, up from an average of $66.52/bbl last year. Similarly, US refiner acquisition costs of domestic and imported crude will climb to an average $108/bbl from $67.93/bbl last year.

Product prices

Average retail gasoline and heating oil prices in 2008 will reach record levels for the 6th year in a row. Strong worldwide demand propelled diesel prices in the first quarter of this year $1/gal higher than in the first quarter of 2007 in the US.

Excluding taxes, the US refiner price of highway diesel fuel climbed to average $3.255/gal this March from $2.055/gal a year earlier, according to the latest figures available from US Energy Information Administration.

Pump prices for motor gasoline have followed crude prices upward as high costs have depressed refining margins, and refinery utilization rates held below 90% through the first half of this year. Inventories of motor gasoline finished the first half near the midpoint of the 5-year range.

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OGJ FORECAST OF US OIL SUPPLY AND DEMAND

Table 2

	First half 2008 Volume 1,000 b/d	First half 2008 % change from 2007	Year 2008 Volume 1,000 b/d	Year 2008 % change from 2007
DEMAND				
Motor gasoline	9,125	–0.9	9,200	–0.9
Dist. 1–4	7,540	–0.9	7,606	–0.9
Dist. 5	1,585	–0.9	1,594	–1.0
Jet fuel	1,605	–1.0	1,583	–2.5
Dist. 1–4	1,119	–1.0	1,092	–2.5
Dist. 5	486	–1.2	491	–2.5
Distillate	4,250	–0.4	4,178	–1.1
Dist. 1–4	3,692	–0.4	3,620	–1.1
Dist. 5	558	–0.4	558	–1.1
Residual	665	–14.4	600	–18.3
Dist. 1–4	539	–14.4	472	–18.3
Dist. 5	126	–14.4	128	–18.3
LPG and ethane	2,100	–2.2	1,977	–5.1
Dist. 1–4	2,048	–2.2	1,928	–5.1
Dist. 5	52	–2.2	49	–5.1
Other products	2,605	–3.4	2,710	–1.4
Dist. 1–4	2,291	–3.4	2,387	–1.4
Dist. 5	314	–3.1	323	–1.4
Total domestic demand	**20,350**	**–1.8**	**20,248**	**–2.2**
Dist. 1–4	17,229	–1.8	17,105	–2.2
Dist. 5	3,121	–1.7	3,143	–2.2
Exports	**1,700**	**25.6**	**1,550**	**10.8**
Dist. 1–4	1,453	25.6	1,326	10.8
Dist. 5	247	25.6	224	10.8
Total Demand	**22,050**	**–0.1**	**21,798**	**–1.4**
Dist. 1–4	18,682	–0.1	18,432	–1.4
Dist. 5	3,368	–0.1	3,366	–1.4
SUPPLY				
Domestic production				
Crude and condensate	5,120	–1.3	5,120	0.4
Dist. 1–4	3,737	–1.3	3,735	0.4
Dist. 5	1,383	–1.3	1,385	0.4
NGL and LRG[1]	1,830	4.3	1,850	3.8
Dist. 1–4	1,765	4.3	1,784	3.8
Dist. 5	65	2.7	66	3.8
Total domestic production	6,950	0.1	6,970	1.2
Dist. 1–4	5,502	0.5	5,519	1.4
Dist. 5	1,448	–1.1	1,451	0.5
IMPORTS				
Crude oil	9,800	–2.1	9,700	–3.1
Dist. 1–4	8,736	–2.1	8,589	–3.1
Dist. 5	1,064	–2.1	1,111	–3.2
Products and unfinished oils	3,250	–8.0	3,250	–5.0
Dist. 1–4	2,848	–8.0	2,902	–5.0
Dist. 5	402	–8.0	348	–5.0
Total Imports	**13,050**	**–3.6**	**12,950**	**–3.6**
Dist. 1–4	11,584	–3.6	11,491	–3.6
Dist. 5	1,466	–3.8	1,459	–3.6
Processing gain, loss, etc.	1,700	62.2	1,919	88.3
Dist. 1–4	1,419	62.2	1,537	88.3
Dist. 5	281	62.2	382	88.3
Total new supply	**21,700**	**0.8**	**21,839**	**2.4**
Dist. 1–4	18,506	0.7	18,546	2.1
Dist. 5	3,194	1.0	3,293	4.2
Stock change	**–350**	—	**41**	—
Dist. 1–4	–176	—	114	—
Dist. 5	–174	—	–73	—
Crude runs to stills	**14,845**	**–0.9**	**15,045**	**–0.6**
Total Input to stills	**15,115**	**–1.2**	**15,250**	**–1.2**
Total refining capacity	**17,594**	**0.8**	**17,650**	**1.2**
Refining utilization, %	**85.9**	**–2.0**	**86.4**	**–2.4**
Total industry stocks[2]	**970**	**–6.6**	**980**	**1.6**
Refined products	670	–2.0	690	1.6
Crude oil	300	–15.5	290	1.4
SPR crude oil stocks	706	2.3	710	1.9
IMPORT DEPENDENCY				
Total imports % domestic demand	64.1	—	64.0	—
Net imports % domestic demand	55.8	—	56.3	—

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

OGJ forecasts that the pump price for all types of gasoline in the US will average \$3.67/gal this year, including taxes of 43.6¢/gal. Retail prices were \$2.849/gal on average last year, according to EIA.

The price of residential heating oil excluding taxes will average \$3.60/gal this year, up from \$2.59/gal last year, OGJ forecasts. The price in the first 4 months of 2008 was 39% higher than during the same 2007 period, EIA estimates show.

Natural gas prices

The average wellhead price of US natural gas will surge to \$10/Mcf from \$6.39/Mcf last year. The US is more dependent on domestic supplies this year as imports of LNG and pipeline gas from Canada and Mexico are limited.

Strong electric power demand and the potential for an active Atlantic hurricane season will keep a floor under gas prices through the third quarter of 2008.

EIA preliminary estimates show that for the first 5 moths of this year, the wellhead gas price averaged \$8.32/Mcf.

At the end of trading on July 3, 2008, the price of gas for August delivery was \$13.577/MMbtu, the highest recent closing price since a late-2005 rally, when gas settled as high as \$15.378/MMbtu on Dec. 13, 2005.

US economy

OGJ forecasts that US gross domestic product will grow 1% this year. The final report from the Bureau of Economic Analysis revealed that first-quarter 2008 GDP grew 1% from the preceding quarter.

The federal government's stimulus

First quarter worldwide oil production

Table 3

Country	First quarter 2008	First quarter 2007	Change	Change, %
	——— 1,000 b/d ———			
OPEC	**32,314**	**30,225**	**2,089**	**6.9**
Non–OPEC	**41,254**	**42,222**	**–968**	**–2.3**
Argentina	631	631	—	—
Brazil	1,766	1,754	12	0.7
Canada	2,567	2,615	–48	–1.8
Colombia	560	519	41	7.9
Ecuador	500	499	1	0.2
Mexico	2,911	3,158	–247	–7.8
United States	5,101	5,174	–73	–1.4
Other	2,744	2,798	–54	–1.9
Western Hemisphere	16,780	17,148	–368	–2.1
Norway	2,205	2,426	–221	–9.1
United Kingdom	1,484	1,597	–113	–7.1
Other	583	616	–33	–5.4
Western Europe	4,272	4,639	–367	–7.9
FSU	12,481	12,203	278	2.3
Other	174	180	–6	–3.3
Eastern Europe & FSU	12,655	12,383	272	2.2
Egypt	630	660	–30	–4.5
Gabon	227	230	–3	–1.3
Other	8,788	8,536	252	3.0
Africa	9,418	9,196	222	2.4
Oman	727	723	4	0.6
Syria	390	393	–3	–0.8
Other	21,939	20,598	1,341	6.5
Middle East	23,056	21,714	1,342	6.2
Australia	409	440	–31	–7.0
China	3,771	3,755	16	0.4
India	678	695	–17	–2.4
Malaysia	777	753	24	3.2
Other	1,751	1,724	27	1.6
Asia–Pacific	7,386	7,367	19	0.3
Total world	**73,568**	**72,447**	**1,121**	**1.5**

Source: Oil & Gas Journal

OPEC oil production

Table 4

Country	First quarter 2008	First quarter 2007	Change	Change, %	OPEC quota, 1,000 b/d
	——— 1,000 b/d ———				
Angola[1]	1,891	1,618	—	—	1,900
Algeria	1,390	1,330	60	4.5	1,360
Ecuador[1]	500	499	1	0.2	520
Indonesia	859	850	9	1.1	870
Iran	4,023	3,903	120	3.1	3,820
Iraq[3]	2,383	1,893	490	25.9	—
Kuwait[2]	2,583	2,435	148	6.1	2,530
Libya	1,763	1,693	70	4.1	1,710
Nigeria	2,057	2,227	–170	–7.6	2,160
Qatar	847	797	50	6.3	830
Saudi Arabia[2]	8,993	8,475	518	6.1	8,940
United Arab Emirates	2,623	2,567	56	2.2	2,570
Venezuela	2,400	2,437	–37	–1.5	2,470
Total OPEC	**32,314**	**30,225**	**2,089**	**6.9**	**29,680**

[1]Angola and Ecuador became a member of OPEC beginning in 2007. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. [3]Not included in 2008 quota.
Source: Oil & Gas Journal

payments to US taxpayers, intended to boost consumer spending, will stave off economic contraction in the second and third quarters of 2008.

Although inflation is a threat, largely due to the run-up in oil prices, the

Federal Open Market Committee at its latest meeting decided to keep its target for the federal funds rate, which banks charge each other for overnight loans, at 2%.

The Fed said overall economic activity continues to expand, partly reflecting some firming in household spending. But labor markets have softened, and financial markets remain under stress. Also, tight credit, the housing contraction, and the rise in energy prices are likely to weigh on economic growth over the next few quarters, the Fed stated.

Last year's GDP growth was 2.2%, down from 2.9% a year earlier, slowed by a meltdown in the housing and credit markets. GDP growth in 2005 was 3.1%.

US energy use will grow slower than the economy. Total energy demand in the US this year will grow just 0.4%, and energy efficiency will improve to 8,735 btu/dollar of GDP from last year's rate of 8,784 btu/dollar.

Energy by source

US energy demand this year will total 102.052 quadrillion btu (quads). Although total demand is nearly unchanged from last year, there is a shift in use among the sources.

Petroleum demand will decline, but consumption of gas, coal, and renewable energy sources will climb. Demand for nuclear energy will retreat from last year's record high.

Oil will still command the largest share of the US energy mix, accounting for 38.2% of the market. Total use will be 38.942 quads, a decline of 2.2% from last year. Demand for all major petroleum products will slump this year as a result of high prices.

World crude prices[1]

Table 5

Country	Type of crude and API gravity°	June 1, 2008, $/bbl	% change 6–08/ 1–08	In effect Jan. 1, 2008, $/bbl	% change 08/07	In effect June 1, 2007, $/bbl	In effect June 1, 2006, $/bbl	In effect June 1, 2005, $/bbl	In effect June 1, 2004, $/bbl	In effect June 1, 2003, $/bbl
OPEC										
Saudi Arabia	Arabian Light 34	120.79	29.9	93.02	89.7	63.68	45.96	33.77	23.52	21.57
Abu Dhabi	Murban 39	126.63	33.5	94.85	81.5	69.77	52.67	37.53	26.69	24.98
Algeria	Saharan 44	126.32	28.5	98.28	80.3	70.07	50.07	37.73	27.17	22.92
Nigeria	Bonny Light 37	129.82	31.8	98.52	81.6	71.48	51.61	37.87	27.44	23.32
Libya	Es Sider 37	121.80	25.8	96.79	80.3	67.55	49.88	37.34	26.57	22.67
Indonesia	Minas 34	127.97	30.1	98.34	83.2	69.85	50.81	38.06	28.24	24.51
Venezuela	Tia Juana 31	122.26	30.3	93.85	88.9	64.71	47.69	36.92	27.81	23.18
Total OPEC		**121.52**	**29.9**	**93.56**	**86.6**	**65.11**	**47.29**	**35.09**	**25.04**	**22.47**
OTHER										
UK	Brent Blend 38	125.47	27.5	98.42	80.7	69.43	51.21	37.78	27.58	23.26
Norway	Ekofisk 42	127.92	30.2	98.23	85.3	69.02	50.23	37.63	27.78	23.20
Mexico	Isthmus 33	122.15	30.3	93.74	89.1	64.60	47.58	36.81	27.70	23.07
Russia	Urals 32	119.69	27.4	93.98	84.9	64.74	47.61	35.78	26.16	21.99
Total World		**121.36**	**30.6**	**92.93**	**87.7**	**64.67**	**46.65**	**35.29**	**25.72**	**22.31**
US[2]		117.82	33.3	88.41	84.6	63.84	44.79	34.83	25.50	21.66

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

With demand at 24.47 quads, natural gas will account for 24% of the energy mix this year. In 2007, US demand for gas totaled 23.64 quads. Rising demand for gas in electric power generation and by industrial users will drive this year's climb in gas use.

Coal demand will also increase, though by only 1% to 23 quads, and represent 22.5% of this year's energy consumption. Preliminary estimates show that demand for coal by industrial customers and electric power producers grew sharply in the first half of 2008 from a year ago.

Nuclear energy's share of electricity net generation has been nearly flat for the past few years and will remain so this year. OGJ forecasts that total demand for nuclear energy will be 8.4 quads this year vs. 8.415 quads last year, and nuclear's share of the energy market will be 8.2%.

All forms of renewable energy used in the US this year, including hydroelectric power, will meet 7.1% of total energy demand, up from 6.9% last year. In the first quarter of this year, EIA estimates that hydroelectric power generation was down year-on-year from 2007 by almost 9%.

The renewable energy category also includes solar, wind, geothermal, and biomass. The use of biofuels and wind energy increased in the first quarter of this year, according to early EIA estimates, but the use of solar thermal and photovoltaic electricity net generation was unchanged from first-quarter 2007.

US crude, products, and natural gas prices

Table 6

Year	Average wellhead crude price, $/bbl	Refiner's acquisition cost of crude, $/bbl	Retail motor gasoline, all types, ¢/gal	Residential heating oil, ¢/gal	Average wellhead natural gas price, $/Mcf
1976	8.19	10.89	59.5	40.6	0.58
1977	8.57	11.96	63.1	46.0	0.79
1978	9.00	12.46	65.2	49.0	0.91
1979	12.64	17.72	88.2	70.4	1.18
1980	21.59	28.07	122.1	97.4	1.59
1981	31.77	35.24	135.3	119.4	1.98
1982	28.52	31.87	128.1	116.0	2.46
1983	26.19	28.99	122.5	107.8	2.59
1984	25.88	28.63	119.8	109.1	2.66
1985	24.09	26.75	119.6	105.3	2.51
1986	12.51	14.55	93.1	83.6	1.94
1987	15.40	17.90	95.7	80.3	1.67
1988	12.58	14.67	96.3	81.3	1.69
1989	15.86	17.97	106.0	90.0	1.69
1990	20.03	22.22	121.7	106.3	1.71
1991	16.54	19.06	119.6	101.9	1.64
1992	15.99	18.43	119.0	93.4	1.74
1993	14.25	16.41	117.3	91.1	2.04
1994	13.19	15.59	117.4	88.4	1.85
1995	14.62	17.23	120.5	86.7	1.55
1996	18.46	20.71	128.8	98.9	2.17
1997	17.23	19.04	129.1	98.4	2.32
1998	10.87	12.52	111.5	85.2	1.96
1999	15.56	17.51	122.1	87.6	2.19
2000	26.72	28.26	156.3	131.0	3.68
2001	21.84	22.95	153.1	125.0	4.00
2002	22.51	24.10	144.1	112.9	2.95
2003	27.56	28.53	163.8	135.5	4.88
2004	36.77	36.98	192.3	154.8	5.46
2005	50.28	50.24	233.8	205.2	7.33
2006	59.69	60.24	263.5	236.5	6.40
2007	66.52	67.93	284.9	259.0	6.39
2008*	110.00	108.00	367.0	360.0	10.00

*OGJ estimate.
Source: US Energy Information Administration, for 1976-2007 data

US oil product demand

Oil product consumption in the US this year will decline more than 2% as high prices for transportation fuels and heating oil curb demand.

Motor gasoline demand will average

The world is growing by more than 70 million people a year.

So is that a problem, or a solution?


With our planet's population continuing to increase, and the quality of life for millions in the developing world improving daily, our demand for energy is also growing. And to meet everyone's needs 25 years from now may take 50% more energy than we use today.
Finding and developing all the fuel and power we need for our homes, businesses and vehicles, while protecting the environment, could be one of the greatest challenges our generation will face.
The key to ensuring success is found in the same place that created this need: humanity itself. When the unique spirit we all possess is allowed to flourish, mankind has proven its ability to take on, and overcome, any issue. It's a spirit of hard work, ingenuity, drive, courage and no small measure of commitment. To success, to each other, to the planet.
The problem...becomes the solution.
This human energy that drives us to succeed has been there every day since the beginning. And it will be with us to shape many tomorrows to come.
So join us in tapping the most powerful source of energy in the world. Ourselves.
And watch what the human race can do.
Chevron
Human Energy

US ENERGY CONSUMPTION AND EFFICIENCY

Table 7

	GDP (billion 2000 dollars)	Energy consumption (trillion btu)	Energy consumption per GDP, 2000 dollar (Mbtu)	Oil energy consumption (trillion btu)	Oil energy consumption per GDP, 2000 dollar (Mbtu)	Natural gas energy consumption (trillion btu)	Total natural gas energy consumption per GDP, 2000 dollar (Mbtu)	Total oil and natural gas energy consumption (trillion btu)	Oil and gas energy consumption per GDP, 2000 dollar (Mbtu)	Oil and natural gas energy % of total energy
1973......	4,341.5	75,708	17.4	34,840	8.0	22,512	5.2	57,352	13.2	75.8
1974......	4,319.6	73,991	17.1	33,455	7.7	21,732	5.0	55,187	12.8	74.6
1975......	4,311.2	71,999	16.7	32,731	7.6	19,948	4.6	52,679	12.2	73.2
1976......	4,540.9	76,012	16.7	35,175	7.7	20,345	4.5	55,520	12.2	73.0
1977......	4,750.5	78,000	16.4	37,122	7.8	19,931	4.2	57,053	12.0	73.1
1978......	5,015.0	79,986	15.9	37,965	7.6	20,000	4.0	57,965	11.6	72.5
1979......	5,173.4	80,903	15.6	37,123	7.2	20,666	4.0	57,789	11.2	71.4
1980......	5,161.7	78,280	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	76,580	12.7	30,922	5.1	17,834	2.9	48,756	8.1	63.7
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	84,730	11.9	33,553	4.7	19,730	2.8	53,283	7.5	62.9
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	94,226	11.3	35,757	4.3	23,197	2.8	58,954	7.1	62.6
1997......	8,703.5	94,790	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	96,827	10.2	37,960	4.0	23,010	2.4	60,970	6.4	63.0
2000	9,817.0	98,966	10.1	38,404	3.9	23,916	2.4	62,320	6.3	63.0
2001......	9,890.7	96,304	9.7	38,333	3.9	22,861	2.3	61,194	6.2	63.5
2002	10,048.8	97,793	9.7	38,401	3.8	23,628	2.4	62,029	6.2	63.4
2003	10,301.0	98,103	9.5	39,074	3.8	22,967	2.2	62,041	6.0	63.2
2004	10,703.5	100,199	9.4	40,594	3.8	22,993	2.1	63,587	5.9	63.5
2005	11,048.6	100,505	9.1	40,735	3.7	22,886	2.1	63,621	5.8	63.3
2006	11,415.3	99,661	8.7	40,217	3.5	22,518	2.0	62,735	5.5	62.9
2007	11,566.8	101,603	8.8	39,818	3.4	23,641	2.0	63,459	5.5	62.5
*2008 ...	11,682.5	102,052	8.7	38,942	3.3	24,470	2.1	63,412	5.4	62.1

*Estimated.
Source: US Energy Information Administration

9.2 million b/d this year, down from the 2007 average of 9.29 million b/d.

The US Department of Transportation recently announced that in April of this year, Americans drove less for the 6th month in a row, and mass transit ridership climbed as a result of rising fuel prices. The number of highway miles traveled was down 1.4 billion from April 2007 and down 400 million miles from March of this year.

In search of savings at the pump, drivers are not only taking fewer trips and traveling shorter distances when possible but also seeking more fuel-efficient automobiles in lieu of large sport utility vehicles, as indicated by auto sales trends.

US ENERGY DEMAND

Table 8

	2007	*2008	Change, %	% share of total energy 2007	*2008
	— Trillion btu —				
Oil	39,818	38,942	-2.2	39.2	38.2
Gas	23,641	24,470	3.5	23.3	24.0
Coal.......................	22,767	23,000	1.0	22.4	22.5
Nuclear	8,415	8,400	-0.2	8.3	8.2
Hydro, other.........	6,962	7,240	4.0	6.9	7.1
Total	**101,603**	**102,052**	**0.4**	**100.0**	**100.0**

*OGJ estimate.
Source: 2007 US Energy Information Administration

Demand for gasoline began showing weakness in October 2007, when pump prices rose counterseasonally toward $3/gal. Since then, the average price of gasoline has continued to climb. Motor gasoline demand in the first half of 2008 averaged 9.125 million b/d, down from 9.209 million b/d in the 2007 first half.

Meanwhile, rising jet fuel prices have cut into airline profits, resulting not only in higher passenger fares but also in cuts in the numbers of flights and routes. OGJ forecasts that jet fuel demand will decline 2.5% to 1.583 million b/d this year due to fewer flights.

Strong diesel fuel consumption will limit the decline in distillate demand this year. Because of heavy trucking and rail use, including that used to move ethanol to distribution centers for blending with gasoline, distillate demand will average 4.18 million b/d, down from 4.22 million b/d last year.

Residual fuel oil demand has declined over time as less is used in electricity generation and by industrial customers. This year, OGJ expects an

18% decline in demand for resid to average 600,000 b/d.

Demand for LPG, including propylene, will decline 5% this year across industrial, residential, commercial, and transportation users, averaging 1.977 million b/d.

Demand for all other petroleum products will average 2.71 million b/d this year, down about 1.5%. These products include asphalt and road oil, petroleum coke, lubricants, pentanes plus, petrochemical feedstocks, waxes, and others.

US oil production

As it has each year since 2002, oil production in Alaska will decline this year. Last year Alaskan crude output averaged 719,000 b/d, and EIA's estimates for the first 5 months of 2008 show average production of 705,000 b/d, a nearly 7% reduction from the corresponding 2007 period.

Oil production from the Lower 48 is getting a small boost from higher output in Colorado, Louisiana, and Texas.

OGJ forecasts that US crude and condensate production this year will average 5.12 million b/d, up from 5.103 million b/d last year. Production of NGL and LRG will climb almost 4% to average 1.85 million b/d.

Imports, exports

Because of declining demand for oil in the US, imports will fall off last year's levels. Imports of oil products will decline 5%, averaging 3.25 million b/d, and crude imports will contract 3.1% to 9.7 million b/d.

US net imports will drop to 56.3% of domestic demand for 2008, down from 58.1% last year.

US NATURAL GAS SUPPLY AND DEMAND

Table 9

	2005	2006	2007	Change, %	2008	Change, %
	bcf			07/06	bcf	08/07
Production						
Texas	5,276	5,514	6,093	10.5	6,700	10.0
Louisiana	1,296	1,361	1,327	–2.5	1,393	5.0
Federal Gulf of Mexico	3,132	2,902	2,771	–4.5	2,855	3.0
Other states	9,223	9,605	9,960	3.7	10,212	2.5
Total production	**18,927**	**19,382**	**20,151**	**4.0**	**21,160**	**5.0**
Imports						
Canada	3,700	3,590	3,777	5.2	3,800	0.6
Mexico	9	13	54	315.4	10	–81.5
LNG	631	584	771	32.0	375	–51.4
Total imports	**4,340**	**4,186**	**4,602**	**9.9**	**4,185**	**–9.1**
Supplemental gas	64	66	61	–7.6	60	–1.6
Losses, etc.*	(643)	(821)	(1,111)	35.3	(850)	–23.5
Total new supply	**22,688**	**22,813**	**23,703**	**3.9**	**24,555**	**3.6**
Supply from storage	52	(436)	177	—	200	—
Total supply	**22,740**	**22,377**	**23,880**	**6.7**	**24,755**	**3.7**
Exports	729	724	822	13.5	900	9.5
Total consumption	**22,011**	**21,653**	**23,058**	**6.5**	**23,855**	**3.5**

*Extraction losses and unaccounted for gas.
Source: 2005, 2006, 2007 EIA; 2008 OGJ

FIRST HALF US CRUDE, CONDENSATE PRODUCTION

Table 10

	First half 2008*	First half 2007	Change, %
	1,000 b/d		
PAD District 1	18	21	–14.3
Florida	5	6	–16.7
Others	13	15	–13.3
PAD District 2	463	480	–3.5
Illinois	26	28	–7.1
Kansas	94	100	–6.0
Michigan	15	17	–11.8
North Dakota	113	118	–4.2
Oklahoma	172	175	–1.7
Others	43	42	2.4
PAD District 3	2,952	2,934	0.6
Alabama	15	19	–21.1
Arkansas	13	15	–13.3
Louisiana	1,349	1,326	1.7
Mississippi	50	54	–7.4
New Mexico	165	163	1.2
Texas	1,360	1,357	0.2
PAD District 4	325	357	–9.0
Colorado	45	41	9.8
Montana	92	102	–9.8
Utah	44	54	–18.5
Wyoming	144	160	–10.0
PAD District 5	1,362	1,394	–2.3
Alaska	708	725	–2.3
California	653	668	–2.2
Others	1	1	—
Total	**5,120**	**5,186**	**–1.3**

*OGJ estimate.
Source: US Energy Information Administration

US REFINERY UTILIZATION

Table 11

	Crude runs	Input to distillation units	Operable capacity	Utilization rate,
	1,000 b/d			%
1987	12,851	12,999	15,643	83.1
1988	13,246	13,447	15,927	84.4
1989	13,401	13,551	15,701	86.3
1990	13,409	13,610	15,623	87.1
1991	13,301	13,508	15,707	86.0
1992	13,411	13,600	15,460	87.9
1993	13,613	13,851	15,143	91.5
1994	13,866	14,032	15,150	92.6
1995	13,973	14,119	15,346	92.0
1996	14,195	14,337	15,239	94.1
1997	14,662	14,831	15,594	95.2
1998	14,889	15,108	15,802	95.6
1999	14,804	15,078	16,282	92.6
2000	15,067	15,296	16,525	92.6
2001	15,086	15,351	16,512	92.6
2002	14,947	15,180	16,700	90.7
2003	15,304	15,503	16,747	92.6
2004	15,517	15,781	16,982	93.0
2005	15,220	15,479	17,128	90.4
2006	15,240	15,598	17,400	89.7
2007	15,143	15,443	17,447	88.5
*2008	15,045	15,250	17,650	86.4
1990-2008 change				
Volume	1,636	1,640	2,027	—
Percent	12.2	12.0	13.0	—
2007-08 change				
Volume	(98)	(193)	203	—
Percent	–0.6	–1.2	1.2	—

Source: US Energy Information Administration

US OIL IMPORTS

Table 12

Sources of crude imports[1]

Country	Share of total 2008 %	First quarter average 2008, 1,000 b/d	Change 08/07, %	Annual average 2007, 1,000 b/d	Change 07/06, %	Annual average 2006, 1,000 b/d
Angola[2]	4.4	433	–12.7	496	–3.3	513
Ecuador[2]	2.2	217	9.6	198	–27.2	272
Indonesia	0.1	14	–6.7	15	–6.3	16
Nigeria	11.3	1,102	1.8	1,082	4.3	1,037
Saudi Arabia	15.8	1,541	6.1	1,453	2.1	1,423
Venezuela	10.1	980	–14.8	1,150	0.7	1,142
Other OPEC	13.0	1,268	26.8	1,000	163.2	380
Total OPEC	**57.0**	**5,555**	**3.0**	**5,394**	**12.8**	**4,783**
Canada	19.4	1,886	1.2	1,864	3.4	1,802
China	0.1	10	66.7	6	–68.4	19
Colombia	1.8	174	27.0	137	–2.8	141
Gabon	0.6	54	–14.3	63	5.0	60
Mexico	12.5	1,220	–13.5	1,410	–10.6	1,577
Norway	0.1	14	–75.0	56	–42.9	98
Trinidad and Tobago	0.5	49	2.1	48	–28.4	67
UK	0.8	80	–21.6	102	–21.5	130
Other Non–OPEC	7.2	702	–25.1	937	–35.0	1,441
Total imports	**100.0**	**9,744**	**–2.7**	**10,017**	**–1.0**	**10,118**

Sources of refined product imports

Country	Share of total 2008 %	First quarter average 2008, 1,000 b/d	Change 08/07, %	Annual average 2007, 1,000 b/d	Change 07/06, %	Annual average 2006, 1,000 b/d
Algeria	7.0	220	–3.1	227	–23.3	296
Saudi Arabia	0.5	15	–58.3	36	–12.2	41
Venezuela	5.5	172	–18.5	211	–23.8	277
Other OPEC	3.5	109	–6.0	116	–2.5	119
Total OPEC	**16.4**	**516**	**–12.5**	**590**	**–19.5**	**733**
Canada	20.5	646	15.2	561	1.8	551
Colombia	0.8	26	52.9	17	30.8	13
Italy	1.5	48	–12.7	55	–5.2	58
Mexico	3.5	111	–10.5	124	–3.9	129
Netherlands Antilles	0.5	17	88.9	9	–71.9	32
Virgin Islands	10.8	340	–1.7	346	5.5	328
Other Non–OPEC	45.8	1,440	–16.3	1,720	–1.4	1,745
Total imports	**100.0**	**3,144**	**–8.1**	**3,422**	**–4.7**	**3,589**

[1]Includes imports for the Strategic Petroleum Reserve. [2]Angola and Ecuador became a member of OPEC in 2007.
Source: US Energy Information Administration

FIRST HALF US CRUDE AND PRODUCTS STOCKS

Table 13

	[1]2008, 1,000 bbl	Change 08/07, %	[1]2007, 1,000 bbl	Change 07/06, %	[1]2006, 1,000 bbl
Motor gasoline	210,900	2.0	204,913	–3.9	213,292
Jet fuel	39,600	–1.2	41,185	4.6	39,388
Distillate fuel oil	120,700	–2.6	123,449	–5.0	129,912
Residual fuel oil	40,000	11.9	36,118	–15.5	42,726
Unfinished oils	85,400	–3.9	88,850	–2.5	91,158
Other	173,400	2.5	189,428	0.9	187,667
Total products stocks	**670,000**	**0.9**	**683,943**	**–2.9**	**704,143**
Crude stocks[2]	300,000	–18.3	354,791	5.4	336,735
Total	**970,000**	**–5.7**	**1,038,734**	**–0.2**	**1,040,878**

[1]At end of June. [2]Excludes Strategic Petroleum Reserve.
Source: US Energy Information Administration, 2006-2007. 2008, OGJ estimate

The source of the most US gross imports of crude and products last year was Canada, followed by Mexico, then Saudi Arabia, Venezuela, and Nigeria.

The US will export 1.55 million b/d of crude and products this year, OGJ forecasts, with most of this being oil products. In 2007, the US exported an average 23,000 b/d of crude and 1.37 million b/d of products.

Oil inventories

Crude and product stocks in the US will be able to build by only a small margin this year after closing 2007 at uncomfortably low levels.

OGJ expects commercial oil stocks to build less than 2%, putting inventories of crude at 290 million bbl and product stocks at 690 million bbl at yearend 2008.

Industry stocks of crude at the midyear point stood at 300 million bbl, down from 354 million after the first half of 2007. Crude in the Strategic Petroleum Reserve (SPR) totaled 706 million bbl, up 2% from the end of the first half of 2007.

The Department of Energy will defer about 2.1 million bbl of royalty-in-kind exchange crude oil that had been scheduled for delivery to the SPR this summer in accordance with the Energy Policy Act of 2005, which directs the SPR to fill to its 1 billion bbl capacity.

The crude will be deferred until March-May 2009, after the heating season. Deliveries of about 2.8 million bbl were not deferred and will continue through this month, as shipment of these barrels was under way and could not be practicably deferred, DOE announced.

At the close of the first half of 2008, distillate stocks were down almost 3 million bbl from a year earlier to 120.7 million bbl, as inventories of heating oil were below their 5-year range, and diesel stocks were higher than their 5-year range. Meanwhile, total gasoline stocks were up more than 6 million bbl from mid-2007 to 210.9 million bbl.

Refining

Refinery utilization will average 86.4% this year on operable capacity of

17.65 million b/d, OGJ forecasts.

A combination of factors is holding utilization relatively low this year, including heavy maintenance during the first half and weak refining margins in the face of high input costs and weakening demand for gasoline.

Last year, US refinery utilization averaged 88.5%, and in 2006, refineries ran at 89.7% of capacity on average, down from 90.6% in 2005.

Following a stretch of healthy margins, refining margins took a turn downward after peaking in the second quarter of 2007. Cash refining margins were down sharply for the first 5 months of 2008 compared with the same 2007 period.

Especially hard hit were margins on the US East Coast, where cash refining margins averaged 73% lower than a year earlier, according to Muse, Stancil, & Co. Meanwhile, the average East Coast cash margin for January 2008 was 82¢/bbl vs. a $10.04/bbl margin for refiners on the West Coast that month.

For the first 5 months of this year, the West Coast cash refining margin averaged $14.99/bbl, down 46% from a year earlier. And Gulf Coast margins averaged $9.46/bbl, down 37% from the first 5 months of last year.

US gas market

Natural gas production and imports this year will outpace demand growth, even though demand for gas by power producers will be robust. OGJ forecasts that US gas demand will increase 3.5% following last year's 6.5% growth.

The National Oceanic and Atmospheric Administration's Climate Prediction Center announced in May that projected climate conditions point to a near-normal or above-normal hurricane season in the Atlantic Basin this year. If so, the storms have the potential to affect offshore gas production, but OGJ forecasts that total US production of gas will climb 5% this year.

Last year total US gas production increased 4%, with output moving higher in Texas and some other key producing states but lower in Louisiana and in the federal Gulf of Mexico.

Declining gas production in Canada and the demand for gas in the production of oil sands, domestic demand in Mexico, and crashing LNG imports will drag down US gas imports 9% from last year.

Cold winter weather early this year increased residential gas use, leaving storage levels low during the spring. After a stockbuild during April and May, injections to storage slowed in June due to hot weather as cooling season drove electricity demand.

At the end of the first half of this year, working gas in storage stood at 2.1 tcf, down from 2.5 tcf a year earlier and just below the midpoint of the 5-year range.

Production in the second half of this year from some major projects, including Anadarko's Independence Hub, will keep a floor under gas inventories. US gas exports will increase this year nearly 10% to 900 bcf. ✦

Drilling on upswing in US as Canada pulls from slump

Alan Petzet
Chief Editor-Exploration

Oil and gas drilling is on the upswing in the US in 2008, and drilling in Canada is coming back after slumping in 2007.

OGJ looks for the drilling of 7% more wells in the US this year than last and a slight gain in Canada.

The pace of drilling in the rest of the world is up about 7% from January through May 2008, according to international active rig statistics.

Year over year gains for January through May were posted in all geographic regions: Western Hemisphere excluding the US and Canada, Asia-Pacific, Africa, Middle East, and Europe.

Here are highlights of OGJ's midyear drilling forecast for 2008:

- Operators will drill 50,475 wells in the US, up from an estimated 47,057 wells drilled in 2007.
- All operators will drill 5,246 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 1,840 rigs/week this year, up from 1,768 in 2007 and 1,649 in 2006.
- Operators will drill 18,605 wells in western Canada, up from an estimated 18,391 wells in 2007.

World activity

The rest of the world excluding the US and Canada had 1,058 rigs at work at the beginning of June 2008.

That compared with 931 rigs working in all of Texas and 1,886 rigs running in the US at the same time.

Not a single country outside the US and Canada averaged even 100 rigs working in January through May 2008, according to Baker Hughes. The closest was Mexico with 99 active rigs. Indonesia averaged 83, Argentina 82, Venezuela 81, and Saudi Arabia 78.

Algeria was the busiest country

in Africa, with 27 rigs running, and in Europe the UK had 20, Romania 20, and Norway 18.

A midyear survey by Lehman Bros. indicated that a 20% increase in world exploration and production spending can be expected in 2008 (OGJ, June 16, 2008, Newsletter). This includes outlays for project costs other than drilling.

The results implied a 15% spending hike in the US, 11% in Canada, and 22% in all other countries this year even after companies overspent their 2007 budgets by $8.5 billion worldwide.

US plays

Shale and other unconventional gas plays were claiming large shares of the drilling in Texas and numerous other states.

East Texas Dists. 5 and 6, with the Jurassic Bossier and Cotton Valley and other gas plays, led the state by averaging more than 300 rigs/week in the first half of 2008 even before the Jurassic Haynesville shale play has a chance to strengthen.

The Texas Railroad Commission issued 355 permits for the drilling of deep Bossier wells to 33 operators in 2007, compared with 291 permits in 2006.

Texas Panhandle counties averaged 75 rigs/week, up from 57 rigs in January through May 2007.

Oklahoma averaged about 200 rigs/week through May compared with 180 a year earlier.

Colorado drilling averaged about 15% higher in the first half of 2008, and the state had more than 100 rigs at work in its far-flung basins. One operator, Williams Cos., Tulsa, was running 26 rigs in the Piceance basin at the end of June.

With the Bakken shale oil play moving eastward, Montana's rig count fell to 11 rigs/week from 20 rigs/week in 2007 while North Dakota's averaged 57 rigs/week versus 33. North Dakota added 147 wells producing from the Bakken in 2007, compared with 7 to 15 wells each for the state's other oil producing formations.

Utah, which had a particularly difficult winter for drilling operations, was down only slightly at 40 rigs/week.

Canadian outlook

Drilling in Canada is showing initial signs of a turnaround from weakness the past few years, especially in gas drilling.

Baker Hughes, which counts only rigs actually making hole, tallied an

How US, Canada drilling compare — Table 1

Average number of active rigs per week, year to date

	Jan. 1–June 29, 2007	Jan. 1–June 27, 2008
Alabama	4.1	4.1
Alaska	9.4	7.4
Arkansas	43.3	44.0
California	33.3	38.1
Land	31.6	36.9
Offshore	1.7	1.2
Colorado	102.6	114.0
Florida	0.4	0.1
Kansas	13.4	10.9
Kentucky	9.0	10.0
Louisiana	185.9	149.5
N. land	56.7	52.2
S. inland waters	23.9	20.0
S. land	38.0	25.5
Offshore	67.3	51.9
Michigan	1.4	0.8
Mississippi	16.4	11.3
Montana	19.8	11.3
Nebraska	0.1	0.1
Nevada	1.9	3.2
New Mexico	80.2	73.6
New York	6.8	6.3
North Dakota	33.7	58.7
Ohio	12.9	11.8
Oklahoma	183.1	203.1
Pennsylvania	14.2	20.1
South Dakota	1.9	1.7
Tennessee	3.9	4.8
Texas	820.2	886.8
Offshore	10.2	8.8
Inland waters	0.9	2.5
Dist. 1	21.8	23.9
Dist. 2	29.5	34.3
Dist. 3	58.0	62.2
Dist. 4	92.1	91.6
Dist. 5	164.6	182.8
Dist. 6	123.9	121.1
Dist. 7B	38.8	32.0
Dist. 7C	54.0	60.2
Dist. 8	107.9	128.3
Dist. 8A	25.9	22.5
Dist. 9	34.6	40.5
Dist. 10	58.1	76.2
Utah	41.7	40.3
Virginia	2.4	4.2
West Virginia	30.8	26.4
Wyoming	74.8	71.0
US total	**1,749.9**	**1,817.0**
US land	**1,645.5**	**1,732.0**
US offshore	**79.9**	**62.4**
Canada total	**332.7**	**341.2**

Source: Baker Hughes Inc.

International rig count — Table 2

Average number of active rigs per month, year to date

	Jan. 2007–May 2007	Jan. 2008–May 2008
WESTERN HEMISPHERE		
Argentina	86	82
Bolivia	3	2
Brazil	39	46
Chile	1	1
Colombia	30	40
Ecuador	11	7
Mexico	89	99
Peru	7	7
Trinidad	7	6
Venezuela	77	81
Other	2	1
Total Western Hemisphere*	**353**	**373**
ASIA-PACIFIC		
Australia	20	26
Brunei	4	3
China-offshore	18	20
India	84	83
Indonesia	51	65
Japan	2	3
Malaysia	16	11
Myanmar (Burma)	10	8
New Zealand	4	5
Papua New Guinea	3	4
Philippines	0	1
Taiwan	0	0
Thailand	11	11
Vietnam	7	7
Other	4	3
Total Asia-Pacific	**234**	**249**
AFRICA		
Algeria	25	27
Angola	5	5
Congo	3	2
Gabon	3	2
Kenya	0	0
Libya	12	15
Nigeria	7	9
South Africa	0	0
Tunisia	3	4
Other	6	2
Total Africa	**64**	**67**
MIDDLE EAST		
Abu Dhabi	13	12
Dubai	1	1
Egypt	42	52
Iran	0	0
Iraq	0	0
Jordan	1	0
Kuwait	13	12
Oman	45	54
Pakistan	19	20
Qatar	11	11
Saudi Arabia	76	78
Syria	22	21
Yemen	14	14
Other	1	1
Total Middle East	**258**	**275**
EUROPE		
Croatia	1	0
Denmark	3	2
France	1	1
Germany	5	8
Hungary	2	3
Italy	4	5
Netherlands	5	3
Norway	19	18
Poland	2	2
Romania	2	20
Turkey	5	5
United Kingdom	27	20
Other	5	7
Total Europe	**80**	**94**
Total World	**989**	**1,058**

*Excludes US and Canada.
Source: Baker Hughes Inc.

Oil & Gas Journal well forecast for 2008

Table 3

State	First half 2008 Total wells	First half 2008 Exploratory wells	First half 2008 Field wells	Full year 2008 Total wells	Full year 2008 Exploratory wells	Full year 2008 Field wells	Full year 2008 Total footage (1,000)
Alabama	230	12	218	471	24	447	2,033
Alaska	65	2	63	135	5	130	861
Arizona	2	2	0	5	5	0	9
Arkansas	397	67	330	810	138	672	5,422
California land	1,470	49	1,421	2,905	96	2,809	13,415
California offshore	3	0	3	8	0	8	49
Colorado	1,902	510	1,392	3,825	1,025	2,800	23,053
Florida	0	0	0	1	0	1	13
Illinois	194	60	134	380	117	263	914
Indiana	68	22	46	130	42	88	196
Kansas	1,240	102	1,138	2,505	205	2,300	9,662
Kentucky	474	19	455	965	39	926	2,679
Louisiana	1,049	96	953	2,125	196	1,929	20,075
North	568	49	519	1,155	100	1,055	10,277
South	237	13	224	475	27	448	4,849
Offshore	244	34	210	495	69	426	4,949
Michigan	239	47	192	490	97	393	801
Mississippi	119	12	107	250	25	225	2,242
Montana	346	47	299	709	97	612	4,480
Nebraska	28	7	21	57	15	42	280
Nevada	3	2	1	5	4	1	25
New Mexico - East	577	41	536	1,145	81	1,064	9,090
New Mexico - West	449	6	443	915	13	902	5,409
New York	52	2	50	105	4	101	387
North Dakota	298	64	234	620	133	487	6,597
Ohio	567	56	511	1,155	114	1,041	4,813
Oklahoma	1,980	93	1,887	3,975	187	3,788	28,878
Pennsylvania	2,062	184	1,878	4,100	365	3,735	10,090
South Dakota	27	3	24	55	7	48	210
Tennessee	93	34	59	188	70	118	422
Texas	7,735	712	7,023	15,565	1,436	14,129	130,614
Dist. 1	298	26	272	605	53	552	3,802
Dist. 2	404	65	339	820	133	687	7,191
Dist. 3	478	65	413	950	130	820	7,914
Dist. 4	712	67	645	1,440	135	1,305	14,141
Dist. 5	852	34	818	1,680	67	1,613	18,394
Dist. 6	863	106	757	1,740	214	1,526	17,920
Dist. 7-B	607	25	582	1,240	52	1,188	6,217
Dist. 7-C	784	44	740	1,555	87	1,468	12,485
Dist. 8	1,030	64	966	2,080	129	1,951	16,742
Dist. 8-A	446	44	402	905	89	816	4,997
Dist. 9	600	17	583	1,225	36	1,189	6,148
Dist. 10	620	140	480	1,235	279	956	13,795
Offshore	41	15	26	90	32	58	867
Utah	569	114	455	1,160	232	928	9,103
Virginia	270	38	232	555	78	477	1,476
Washington	1	1	0	1	1	0	15
West Virginia	992	144	848	2,010	291	1,719	8,729
Wyoming	1,559	51	1,508	3,150	104	3,046	13,580
US total	**25,060**	**2,599**	**22,461**	**50,475**	**5,246**	**45,229**	**315,622**
Western Canada	**8,279**	**1,689**	**6,590**	**18,605**	**3,791**	**14,814**	**77,509**
Alberta	5,952	1,184	4,768	13,525	2,691	10,834	53,153
Saskatchewan	1,743	333	1,410	3,765	719	3,046	14,710
Brit. Columbia	427	153	274	935	335	600	8,317
Manitoba	157	19	138	380	46	334	1,329
NWT + Yukon Terr.	4	3	1	12	10	2	80
Eastern offshore	3	1	2	6	2	4	40
Eastern land	67	7	60	135	15	120	271

average 349 rigs in Canada in January through May compared with 346 in the same period of 2007.

The resurgence can be attributed partly to stronger gas and oil prices, partly to operators' expectations for exploiting newer plays such as Bakken shale oil and shale gas in the Montney, Muskwa, and other formations, and returning to coalbed methane and other gas programs. ✦

Petrobras revising projects for new business plan

Eric Watkins
Senior Correspondent

The chief executive officer of Brazil's Petroleo Brasileiro SA (Petrobras), revisiting proposed changes in the country's oil law, said the state firm will present a new business plan later this year.

Sergio Gabrielli, speaking at the 4-day World Petroleum Congress in Madrid, said the company is revising 25 projects to be included in the new plan, which also would include developments in Brazil's promising presalt offshore area.

Gabrielli's statement appears to differ from an earlier decision by the government to withdraw 41 promising oil blocks in the presalt area from a coming exploration and production block auction.

According to reports, the blocks were withdrawn while ministers consider changes in the country's oil legislation that would guarantee a higher percentage for the government from crude oil production.

Under the current system, oil companies purchase a concession from the Brazilian government to explore for oil within the area of a defined block, often in partnership with Petrobras.

As a reward for the risk being assumed, the state hands control of any oil discovered to the operating companies and is paid royalties instead of oil.

According to analyst BMI, however, "It would appear that many in the Brazilian government now support the implementation of production-sharing agreements, under which hydrocarbon reserves remain state property and international oil companies are given a share of output."

Gabrielli recently defended the proposed revision of Brazil's oil legislation, saying that the existing regulations made investment so risk-free that it was like purchasing a "winning lottery ticket" especially since, in his view, the exploratory risk is very low in the presalt area where blocks to be auctioned off share geological conditions similar to those where the previous discoveries were made.

Echoing earlier statements by Brazilian President Luiz Inacio Lula da Silva, who last year said that those blocks in the presalt play that have already been auctioned off won't have their contract terms changed, Gabrielli said Petrobras was carefully considering the impact of reform and that any rule changes would apply only to new concessions, not existing contracts.

That view was welcomed by ExxonMobil Corp. Chief Executive Officer Rex Tillerson, who stressed the need for regulatory stability in Brazil, given the expected high cost to develop promising new oil fields in the country.

"Brazil's government said it will honor existing contracts," said Tillerson at the Madrid conference. "I'm pleased to hear they will keep existing agreements."

ExxonMobil has a 40% operating stake in Brazil's BM-S-22 block, which is adjacent to the BM-S-9 block where Petrobras has discovered oil in the Carioca and Guara wells. The BM-S-22 also is near the Tupi find, where Petrobras last year said it estimates reserves to be as much as 8 billion boe.

"We're still in the early stages of this new play," said Tillerson, underlining the risks posed by his company's investment. "Technologically, it's going to be one of the most difficult in the world, and one of the most expensive."

ExxonMobil, operator, holds a 40% stake in the BM-S-22 block, Hess Corp. holds 40%, and Petrobras holds the remaining 20%. ✦

Former Saudi oil minister says world reaching third oil crisis

Eric Watkins
Senior Correspondent

Speculation is contributing to higher world oil prices, not imbalances between supply and demand, according to Saudi Arabia's former minister of oil, Sheik Ahmed Zaki Yamani, in a published interview.

Asked if current conditions are approaching a third oil crisis, Yamani said, "Yes, I think so. This is a new oil crisis. Oil prices are very high." He said that the two earlier oil crises of the 1970s were caused by "a lack of supply, but now it is because of problems with the price-setting system" in the futures market.

"Traders buy and sell depending on speculation and rumors, not supply and demand," he told Japan's Nikkei newspaper. "That is why even though Saudi Arabia announced increases in production—300,000 b/d and 200,000 b/d—oil prices in the market did not respond well. On the other hand, prices went so high on reports that the US might attack Iran. So much money is flowing into the market; it's almost like gambling."

'Price will fall'

Despite the current situation regarding prices, Yamani felt that the price will fall to $70/bbl by 2010.

"It will not take so long to see a change in market sentiment, perhaps by 2010," he said. "In addition, there has been a change in the energy consumption mix. China, Japan, the US, and European countries are looking at nuclear energy. There are new types of liquid energy converted from coal and gas. Solar and wind energy sources are emerging: biofuels, hydrogen, and so on. Also China subsidizes oil prices. Without the subsidies, consumption will decrease.

At the same time, Yamani suggested that under extreme conditions the price could range even higher. "If the US or Israeli forces attack Iran. If and only if they attacked, the oil price would go up to $200 immediately. The Strait of Hormuz [would] be shut down by Iran. I do not see the US attacking Iran, based on logical thinking. But you never know."

The former minister noted that the Organization of Petroleum Exporting Countries accounted for 70% of world oil production in the 1970s but that it now produces 40%. He said, "OPEC reduced production and let prices rise, placing a priority on profit. On the other hand, OPEC lost market share. OPEC does not particularly take into account a stable supply of oil in the world market and stable oil prices. Those countries are satisfied with high revenues. This attitude of OPEC has not changed."

In defense of his own policies as the Saudi oil minister, Yamani said he was the only one at OPEC meetings "who insisted on maintaining market share and supplying enough oil to the world market with lower prices. It was 1985 that Saudi Arabia stopped playing a role as the swing producer, and OPEC itself can no longer control the price of oil." ✦

Court overturns Texaco's $100 million tax refund

Nick Snow
Washington Editor

A federal appeals court reversed a US district court's decision granting Texaco Inc. a more than $100 million tax refund, the US Department of Justice said on June 17.

It said that the US Department of Energy originally cited Texaco for selling petroleum products at a price higher than government-mandated ceilings during 1973-81. The company settled the allegation and agreed to pay $1.25 billion plus interest. It deducted the settlement amount as ordinary and necessary business expenses and sought an additional $100 million refund under US Internal Revenue Code Section 1341, DOJ said.

Section 1341 is designed to provide a taxpayer relief from having paid taxes on income that the taxpayer is later required to restore to a third party. It does not apply to "any deduction allowable with respect to an item which was included in gross income by reason of the sale," according to DOJ.

In its appeal of a finding by the federal district court for California's Northern District, DOJ's tax division asked whether this exception to the relief provision applies to all deductions attributable to the sale of inventory or only to sales returns, allowances, or similar items. Texaco had argued that the second condition applied and the federal district court in Northern California had agreed.

The Ninth Circuit Court of Appeals sided with DOJ. It held that the exception's plain meaning precluded Texaco's refund claim, noting that the federal circuit court of appeals recently reached the same conclusion in Pennzoil-Quaker State Co. vs. United States.

The Ninth Circuit Court also determined that, even if there was some ambiguity in the statutory exception (as Texaco argued), the court "would be hard pressed not to defer to the agency's interpretation of the statute" because the Internal Revenue Service's interpretation was reasonable.

Finally, said DOJ, the court noted that although its interpretation of Section 1341 denied relief to certain taxpayers, it was up to Congress, not the courts, to revise the statute to "promote a more equitable consequence."

"The court's decision is important because it reaffirms the judiciary's respect for the language enacted by Congress, and the deference owed to the agency entrusted with enforcing that statutory scheme," said Nathan J. Hochman, assistant US attorney general in charge of DOJ's tax division who argued the case in the Ninth Circuit.

It was not immediately clear if Chevron Corp., which acquired Texaco in 2000, plans to appeal the latest decision. ✦

Aramco to hike oil production capacity by 850,000 b/d

Eric Watkins
Senior Correspondent

Saudi Aramco, repeating long-announced plans, will increase production by yearend by a combined 850,000 b/d from its Khursaniyah, Nuayyim, and Shaybah fields, according to a senior official.

Amin Al Nasser, Aramco's senior vice-president for exploration and production, said the company will bring Khursaniyah on stream by yearend, adding 500,000 b/d of oil production, while boosting output at Shaybah to 750,000 b/d from 500,000 b/d, and bringing newly developed Nuayyim field to 100,000 b/d.

Last year, reports said Saudi capacity increases during 2007-08 would come from the three fields, pushing the total to 11.4 million b/d by yearend 2008 from 10.8 million b/d currently (OGJ Online, Apr. 20, 2007).

Looking farther ahead, Al Nasser said his country's output will increase by an additional 900,000 b/d in fourth-quarter 2009 when Aramco will bring on stream its large-scale Manifa heavy oil field, where construction is now 55% complete.

The field developments are part of Saudi Arabia's plan to raise its daily production capacity, including output from the partitioned neutral zone shared with Kuwait, to 12.5 million b/d of crude oil by yearend 2009, from 11.3 million b/d now.

How to reduce prices

Al Nasser's comments followed a 1-day summit in Jeddah of the world's top oil producing and consuming nations, which discussed ways to reduce crude oil prices from the current $140/bbl.

Saudi Arabia's oil minister Ali Al Naimi told the Jeddah meeting that his country plans to invest some $129 billion in oil exploration and production projects over the next 5 years and to expand pumping capacity to as high as 15 million b/d in the longer run, if necessary.

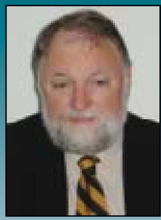
Last month, Saudi officials acknowledged that the Khursaniyah oil field expansion project, which it had planned to bring on stream last December, was still not producing oil, but that much of its 500,000 b/d capacity is ready.

According to Khalid al Falih, Aramco's executive vice-president of operations, the delayed start-up was due to problems in the construction of a gas processing plant in the field. While the Saudi national firm could bring on most of Khursaniyah's capacity if needed, according to Falih, he said the gas would have to be flared—something Aramco wanted to avoid.

"The gas plant is a major delay. It's really a disappointment," Falih said. "All of it will be ready in a few months." ✦

WATCHING GOVERNMENT

Nick Snow, Washington Editor



EIA's short-term outlook

The US Energy Information Administration on July 8 increased its predicted decline in domestic petroleum consumption for 2008 by 100,000 b/d to 400,000 b/d in its latest short-term energy outlook. It cited prospects for a weaker domestic economy and record high crude oil and product prices extending into 2009, when it expects demand to remain "almost flat at the 2008 level."

West Texas Intermediate crude, which averaged $72/bbl in 2007, is projected to average $127/bbl this year and $133/bbl in 2009.

Worldwide, oil markets remain tight as consumption continues to grow despite 7 years of rising prices, and production isn't rising as quickly as expected.

"Preliminary data indicate that world oil consumption during the first half of 2008 rose by roughly 520,000 b/d compared with year earlier levels," it said. The increase reflects a 170,000 b/d year-to-year gain in the first 3 months, followed by an 870,000 b/d increase in the second quarter, the monthly report indicated.

More than offset

"A 760,000 b/d decline in consumption in [Organization for Economic Cooperation and Development] countries during the first half of 2008, mainly concentrated in the US, was more than offset by a 1.3 million b/d increase in non-OECD nations, led by China and the Middle East," it said.

EIA expects worldwide oil demand to climb by almost 1.2 million b/d during 2008's second half in response to higher prices, less economic growth and growing pressure on China, India, and other countries to ease price subsidies. Global consumption could rise by 1.4 million b/d in 2009 if Latin America and other regions' economic growth continues. Demand would grow less if US financial strains spread.

Supplies are not growing as quickly as originally anticipated, especially outside the Organization of Petroleum Exporting Countries. In early 2008, EIA predicted that non-OPEC supplies would grow by 860,000 b/d this year and more than 1.5 million b/d in 2009. It now expects increases of 230,000 b/d in 2008 and 830,000 b/d next year, primarily because of less production from Russia and the North Sea and lowered expectations for Brazil.

OPEC falls short

Production growth within OPEC also has been less than expected, rising only 100,000 b/d from the first quarter to an average 32.3 million b/d in the second quarter. Nonetheless, "higher production in Iraq and Angola more than offset lower production in Nigeria caused by security problems and worker strikes," EIA said.

If Saudi Arabia increases production to 9.7 million b/d in July, as it promised, OPEC crude production could average 32.7 million b/d during the third quarter. That would leave available surplus capacity at 1.2 million b/d, all held by the Saudis, it added.

Any industry operating at nearly 99% of capacity will remain vulnerable to surprises boosting consumption or disrupting production. EIA observed. "Such surprises would place additional upward pressure on prices and contribute to oil price volatility." ✦

COMPANY NEWS

Chesapeake, Plains plan Haynesville venture

Plains Exploration & Production Co. agreed to acquire a 20% interest in Chesapeake Energy Corp.'s Jurassic Haynesville shale play leasehold for $1.65 billion in a new joint venture.

Plains also agreed to fund 50% of Chesapeake's 80% share of drilling and completion costs for future JV wells over several years until another $1.65 billion has been paid.

As a result of the transaction, Plains will hold 110,000 net acres of this leasehold and Chesapeake will hold 440,000 net acres.

In other recent company news:

• Quicksilver Resources Inc. entered into purchase and sale agreements with various private parties to acquire a number of Barnett shale assets for $1.3 billion. Sellers include Chief Resources LLC, Hillwood Oil & Gas LP, and Collins & Young LLC.

• Berry Petroleum Co. agreed to acquire interest in East Texas natural gas production from a consortium of private sellers for $620 million.

• Pacific Rubiales Energy Corp., Toronto, will buy Kappa Energy Holdings Ltd. of Colombia for $168 million.

• Endeavour International Corp. has offered to buy Ithaca Energy Inc. for as much as $150 million in cash and shares to bolster its North Sea assets.

• Oklahoma City-based Quest Resources Corp. plans to buy private PetroEdge Resources LLC for $140 million, closing by mid-July.

• A Talisman Energy Inc. unit plans to invest as much as $125 million within 18 months to earn working interest in properties owned by Hallwood Energy LP.

• Arrow Energy, Brisbane, has signed a major agreement with Shell Exploration Co. BV under which Shell will pay up to $776 million (Aus.) for interests in Arrow's Australian and international coal seam methane (CSM) projects.

• Australian power retailer Origin Energy Ltd., Sydney, has formally rejected the unsolicited $13.8 billion (Aus.) takeover bid from BG Group.

• Dutch energy firm Nuon announced a €476.7 million deal to acquire the Norwegian North Sea energy assets of ConocoPhillips.

• Canadian Imperial Venture Corp. has agreed to acquire 100% of the assets of Encore Investments Ltd., including 25 sections of land in southern Alberta and interests in a number of producing oil and gas wells.

• ATP Oil & Gas Corp. acquired a 55% working interest in the Gulf of Mexico's Green Canyon Blocks 299 and 300, collectively known as Clipper.

• InterOil, the Canadian company working in Papua New Guinea, sold its retention leases in the western sector of the country to concentrate on its potentially high yielding Elk-Antelope field in eastern Papua New Guinea.

• ExxonMobil Corp. reported June 12 it will sell its 820 company-owned stations and 1,400 dealer-operated retail outlets due to tightening profits.

• Wholly owned subsidiaries of Ute Energy LLC and Anadarko Petroleum Corp. formed Chipeta Processing LLC in the Unita basin of Utah.

• Eni SPA and Petroleo Brasileiro SA (Petrobras) renewed their commitment to work closely together on upstream and downstream operations, plus feasibility studies on renewables in Brazil and elsewhere.

• OAO Gazprom opened an office in Algeria, aimed at developing opportunities in Africa and in particular with Sonatrach, the nation's state owned oil company.

Plains-Chesapeake

Chesapeake said it plans to continue acquiring leasehold in the Haynesville shale, and Plains will have the right to 20% participation in any additional leasehold.

The core area of the play spans 3.5 million acres in Texas and Louisiana, Chesapeake told analysts in a conference call.

Acreage on the Texas side may be harder to lease, Chesapeake said. It did not disclose the core area's location but expects core and noncore areas to develop.

Chesapeake said average estimated ultimate reserves in the core area are estimated to average 4.5-8.5 bcf of gas equivalent for each well.

A well in the play now costs $6.5 million. As with other shale plays, these results are likely to improve over time.

The companies currently plan to develop the Haynesville shale using 80-acre spacing, which could support the drilling of as many as 6,875 horizontal wells on the leasehold.

Chesapeake is running five operated rigs in the Haynesville shale play and anticipates operating at least 12 rigs by yearend 2008, at least 30 rigs by yearend 2009, and as many as 60 rigs by yearend 2010. Under this plan, the companies anticipate drilling at least 600 wells in 3 years.

Quicksilver Resources

Quicksilver is acquiring production, leaseholds, royalties, and midstream assets in Tarrant and Denton counties of Texas.

The properties have net production of 45 MMcfd of gas. Quicksilver estimates that these properties hold 350 bcf of proved gas reserves, of which 40% are proved developed. Quicksilver is paying $1 billion in cash and $307 million in common stock. The acquisitions are scheduled to close in August.

Upon closing, Quicksilver estimates that its total average 2008 production volume will increase to 275 MMcfd of gas equivalent, an 8% increase from earlier estimates.

Berry Petroleum

Berry Petroleum's transaction involves 4,500 net acres in Limestone and Harrison counties. The acquisition, which includes a $20 million gathering system, marks Berry Petroleum's entry into the East Texas basin.

Berry Petroleum of Bakersfield, Calif., will operate the properties upon closing, expected by July 15. The acquisition will add 32 MMcfd of gas equivalent to Berry's production from 100 producing wells.

Estimated proved reserves associated with the properties are 335 bcf of gas equivalent, with 29% being proved developed reserves.

Berry identified more than 100 drilling locations targeting stacked pay in various productive zones including the Pettit, Travis Peak, Cotton Valley Sands, Cotton Valley Lime, and Bossier sands.

Pacific Rubiales

Kappa Energy, operating since 1997, holds 747,000 gross acres in nine operating blocks in the Catatumbo, Llanos, and Lower, Middle, and Upper Magdalena basins.

Kappa Energy holds the following net working interests: Abanico block, 22.5% in the production area, 23.8% and 14.8%, respectively, in the Santana and Casablanca exploration areas, and 30.5% in the remaining exploration areas, Alhucema 50%, Arrendajo 32.5%, Cerrito average 75%, Chipalo 50%, Cicuco 100% for gas and oil, Guasimo 100%, Buganviles 49%, and Las Quinchas 50%.

The Abanico contract area includes the main oil producing field, Abanico, making 4,100 b/d, and Ventilador gas field making 4.3 MMcfd. Guasimo, Alhucema, and Arrendajo are in the drilling phase.

Kappa Energy had 9.3 million boe of proved and probable reserves as of May 31.

Pacific Rubiales operates numerous blocks in Colombia and three blocks in Peru.

Endeavour-Ithaca Energy

Endeavour sent a nonbinding letter to the Ithaca Energy board, setting out its proposal, which represents a premium of 44.2% on Ithaca's closing price on June 18. Endeavour, which already holds a 2.4% of Ithaca's current issued share capital, has offered an indicative price of $3.25/Ithaca share.

William Transier, Endeavour's president and chief executive, said: "Our two companies have similar strategic focus on the upstream business in the North Sea. With Endeavour's current cash flow and growing production profile, the risk of timely execution of Ithaca's development projects is reduced, and the ability to realize total value for shareholders is significantly increased."

Ithaca said it would review the unsolicited offer in light of its long-term strategic plan. It has interests in 30 blocks or partial blocks under 16 licenses covering more than 514,000 acres.

Endeavour estimates that its production in 2008 will average 8,600-9,000 boe/d. It plans to drill and appraise 15 North Sea exploration and appraisal wells later in 2008 and 2009.

Quest

PetroEdge owns 78,000 net acres of gas and oil producing properties in West Virginia, Pennsylvania, and New York. The properties, 100% operated and 99% gas, produce 3.3 MMcfd of gas equivalent from 99.6 bcf of gas equivalent of proved reserves.

Some 67,000 acres are in the Devonian Marcellus shale play fairway, including 41,000 net acres in Ritchie, Wetzel, and Lewis counties, WVa., 22,000 net acres in Lycoming County, Pa., and 3,000 net acres in Steuben County, NY. The acquisition will bring Quest's Marcellus play holding to 119,000 net acres.

PetroEdge had drilled and completed 112 wells on its properties since the end of 2004, all of which were productive. The properties have 700 potential drilling locations assuming vertical development on 80-acre spacing.

The first two horizontal Marcellus wells are drilling in Wetzel County, and drilling is to start in Lycoming County by yearend.

Talisman-Hallwood

Talisman Pres. and Chief Executive Officer John Manzoni said, "This agreement gives us exposure in a number of

PERSONNEL MOVES AND PROMOTIONS

EnCana names executives for newly split companies

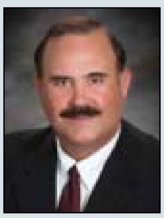
Canadian oil and gas firm EnCana Corp., which in May announced a bifurcation of its oil and gas businesses into separate companies, has designated the executives who will head the new firms.

GasCo executives include: **Randall K. Eresman**, president and chief executive officer; **Sherri Brillon**, executive vice-president and chief financial officer; **Mike Graham**, executive vice-president and president, Canadian division; **Bill Oliver**, executive vice-president and chief corporate officer; and **Jeff Wojahn**, executive vice-president and president, USA division.

IOCo executives include: **Brian Ferguson**, president and chief executive officer; **Ivor Ruste**, executive vice-president and chief financial officer; and **Don Swystun**, executive vice-president and president, Canadian Plains division.

Upstream moves

Medco Energi US has appointed four vice-presidents in a realignment of executive positions.



Fruge

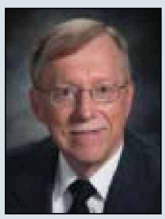
The appointed executives and new positions are: **Daniel Fruge**, vice-president and chief financial officer; **Steve Goff**, vice-president, petroleum engineering; Gary **Johnson**, vice-president, production operations; and Ted **Russell**, vice-president, drilling and capital projects.

Goff

Johnson

Medco has also promoted **John Young** to senior vice-president, exploration and development.

Young has more than 25 years of engineering and management experience in the oil and gas industry. He previously served as manager of business development for Medco. He also has held various positions, including midvalue negotiated project manager for The Oil and Gas Asset Clearinghouse and vice-president, strategic planning and business development, for Baker Energy.



Russell

Young

Enterra Energy Corp. has appointed **Don Klapko** as president, chief executive officer, and a director of the company.

Klapko, who has served as a senior executive management consultant to Enterra since November 2007, has more than 30 years of experience in the oil and gas industry. Most recently he served as president and director of Trigger Resources Ltd. Before that he served as vice-president, operations, for Rio Alto Exploration Ltd.

Toreador Resources Corp. has made several management changes.

Michael Fitzgerald, executive vice-president, exploration and production, and **Edward Ramirez**, senior vice-president, exploration and production, both resigned on June 27.

Regional management will now report directly to **Nigel Lovett**, chief executive officer and president.

Separately, **John Gilboux** has been promoted to vice-president, exploration, and will report to Lovett.

areas where we have not been active, including the deep Barnett and Fayetteville shales."

Previously, Manzoni said Talisman would spend $1.1-1.3 billion through 2009 evaluating its unconventional assets in Canada and the US (OGJ Online, May 22, 2008).

Fortuna Energy Inc. Shale LP, a wholly owned limited partnership of Calgary's Talisman, agreed to invest in Hallwood Energy in exchange for a stake in Hallwood's assets in Texas, Arkansas, and Louisiana.

Privately owned Hallwood Group Inc., a diversified holding company, owns 25% of Hallwood Energy of Dallas. Hallwood Energy's 2008 drilling program calls for 11 wells.

The Talisman agreement involves Hallwood's 40% working interest in more than 43,000 acres in the Barnett and Woodford shales in the West Texas counties of Reeves and Culberson.

The agreement also involves Hallwood's 24,500 net acres in the Fayetteville shale in White and Faulkner counties in Arkansas.

In addition to the assets, the agreement includes a technical-services arrangement in which Hallwood's technical staff would assist Talisman for a year.

Manzoni said, "Hallwood has a proven track record in the early-stage development of shale programs, and we will use this to augment our experience in the piloting and development of our unconventional plays."

Shell-Arrow Energy

The preliminary agreement specifies that Shell will acquire 30% of Arrow's Australian upstream permits for an initial sum of $435 million (Aus.). An additional $209 million is payable when a final investment decision has been made and production begun from an LNG project in Gladstone, Queensland,

TXCO Resources Inc., San Antonio, has promoted **Gary S. Grinsfelder** to president.

Grinsfelder, formerly vice-president of exploration, succeeds **James E. Sigmon**, who remains chairman and chief executive officer.

Grinsfelder is a geologist with more than 30 years in the industry. He joined TXCO Resources in April 2007 when it acquired Output Exploration LLC, Houston, where he was vice-president of exploration and business development.

In addition to his role as president, in which he will report to Sigmon, he will manage the company's land, exploration, legal, and investor relations and corporate communications departments.

Norwood Resources Ltd., Vancouver, BC, has named **David Klepacki** its vice-president of exploration.

Klepacki has been consulting for Norwood since July 2007. A geophysicist with 23 years in the industry, he has previously worked with Exxon Production Research, Esso Canada, and PanCanadian Petroleum Corp.

Norwood is evaluating an oil and gas discovery in western Nicaragua.

Approach Resources Inc. has promoted **Glenn W. Reed** to executive vice-president, engineering and operations, and **Ralph P. Manoushagian** to executive vice-president, land.

Reed has more than 28 years of experience in the oil and gas industry. He served as senior vice-president, operations, and was a founding officer of Approach, joining the company as vice-president, operations, in 2002.

Most recently Manoushagian served as senior vice-president, land. He joined Approach in 2004 as land manager.

EnerGulf Resources Inc., Vancouver, BC, has hired **Campbell Cassidy** as exploration manager for the Lotshi Block in Congo (former Zaire).

Cassidy, with more than 20 years' experience as a drilling engineer and manager, has worked for Royal Dutch Shell PLC, BP PLC, Anadarko Petroleum Corp., Santa Fe Snyder Corp., and Baker Hughes Inc. His experience includes stints in Angola, Nigeria, Namibia, China, and the North Sea.

Other moves

The US Minerals Management Service, Gulf of Mexico division, has selected **Mike Saucier** to serve as regional supervisor for field operations.

Saucier began his career with MMS in 1984 as a staff engineer in the agency's Houma, La., district where he worked on production and drilling issues. In 1988 he became the district's drilling engineer and, in 1995 he was promoted to district supervisor, Houma district, in the Gulf of Mexico. Most recently, he served as deputy regional supervisor for district operations in the field operations office.

The Society of Independent Professional Earth Scientists has appointed **H. Jack Naumann Jr.,** an independent petroleum geologist in Midland, Tex., to president for the 2008-09 term.

Other newly appointed 2008-09 officers are vice-president, **Lee M. Petersen** of Weatherford, Tex.; vice-president of national energy, **William R. Finley** of Lafayette, La; secretary, **Marc D. Maddox** of Midland; and treasurer, **Kenneth J. Huffman** of New Orleans.

IFP has appointed **Remi Eschard** director of its geology-geochemistry-geophysics division.

Eschard joined the division in 1989. Since 2005, he has supervised the reservoir characterization issue within the exploration and production technology business unit. Eschard also has worked in reservoir geology and the sedimentology-stratigraphy department within the division.

proposed by LNG Ltd. (LNGL), Perth.

LNGL and Arrow already have a cooperation agreement for Arrow to supply CSM feedstock from its Surat basin fields to LNGL's Gladstone project. The two companies have discussions in progress to increase capacity of the first proposed LNG train to 1.5 million tonnes/year from 1.3 million. A potential second train in Gladstone to be added as further gas reserves are proved would have a similar capacity.

In a rider to the Shell-Arrow agreement, Shell also will pay another $132 million (Aus.) to buy a 10% share in Arrow International, which holds all of Arrow's overseas assets.

In addition, Shell will have a 5-year option to back into any Arrow International project for 50% of Arrow's interest by paying 50% of past costs, although this excludes three CSM licenses in India.

Shell will transfer senior management personnel into the projects, establish a research and development program, and reserve the right to off-take LNG produced from CSM feedstock sourced from the Arrow-Shell permits.

Under the deal, Arrow will remain operator of the upstream assets.

News of the Shell move comes on the heels of the recent announced agreement between Santos and Malaysia's Petronas in which Petronas will take a 40% interest in Santos' proposed Gladstone CSM-LNG project for $2 billion (OGJ, May 19, 2008, p. 32).

Origin-BG

BG launched its bid of $15.50 (Aus.)/share in cash in late June only a month after Origin rejected the UK firm's original unsolicited proposal at the same price.

Origin said it rejected the original proposal after careful consideration of all relevant information including the fact that there appeared to be an increasing appreciation of the value of coal seam methane (CSM) assets.

Subsequent to this rejection the company maintains it has seen a continued strong interest in the coal seam methane sector and a further 10% increase in the West Texas Intermediate oil spot price to levels above $140/bbl.

Origin Chairman Kevin McCann said the company had now undergone a formal tender process and the time for submitting expressions of interest closed on July 4.

McCann said Origin reaffirms its 3P CSM reserves of 10,122 petajoules (notwithstanding BG's scepticism). These resources have been certified by an independent expert and are consistent with the methodology used for other Queensland CSM operators.

He added that Origin has prime acreage in Queensland in terms of quality and quantity of CSM resources.

Nuon acquisitions

Nuon will acquire Burlington Resources Nederland Petroleum BV, giving the company stakes in 35 gas fields in the Norwegian North Sea, gas pipelines, and processing facilities.

The transaction is key to Nuon's determination to become an integrated company across the gas and power value chain. It also adds the essential gas production capabilities to Nuon's existing gas trading, wholesale, and retail activities.

About 28 of the 35 fields are in the joint development area of the Dutch North Sea and Burlington holds interests in the Westgastransport Pipeline and Pipeline Extension, the onshore Den Helder facility with HiCal and LoCal gas processing plants, and the JDA LoCal pipeline. The assets are operated either by NAM or by Wintershall.

Nuon is keen to partner with a foreign company to strengthen its position in the European energy market and continue to acquire interests in gas fields or power plants. The search for a partner is expected to take at least 6 months.

Canadian Imperial

The lands include developed and undeveloped acreage predominantly in Alberta at Black Butte, Coutts, Etzikom, Foremost, Forty Mile, Manyberries, Pakowki, Sapphire, Warner, and Yellow Lake. Working interests of the acquired company average 22% in developed lands and 19% in undeveloped lands. For the most part, Canadian Imperial owns the majority interest and will be operator of the undeveloped lands.

Some of the lands to be acquired are held jointly by Encore and Canadian Imperial through Canadian Imperial's subsidiary, USG Energy Corp. Encore is a former shareholder of USG. Since Canadian Imperial's acquisition of USG in May 2007, Encore has held 17.5 million warrants of Canadian Imperial exercisable at 10¢/share until May 2009.

The warrants will be cancelled on closing of this deal, and Canadian Imperial will issue 17.5 million shares to Encore in exchange for all of the issued and outstanding shares of an Encore subsidiary, transferring title to 100% of the assets of Encore to Canadian Imperial.

ATP-Green Canyon blocks

ATP, which acquired the ownership interest from two independents, will operate both blocks. The value of the transaction was not disclosed.

ATP plans to complete one existing well and sidetrack and complete a second well first production scheduled for late 2009. Four wells drilled in 2005-06 in 3,400 ft of water.

InterOil

The company sold 43.13% of retention lease PRL4, which contains the undeveloped Stanley gas and condensate field, and 28.576% of PRL5, which contains the undeveloped Elevara and Ketu gas and condensate fields, to Horizon Oil Ltd. in Sydney.

InterOil retained first right of refusal to buy any condensate produced from both areas, which will be used as feedstock for the company's oil refinery in Port Moresby.

Horizon has increased its interests in both retention leases in recent few years and sees opportunity for commercial gas development as early as 2009, particularly in PRL4 at Stanley where the company will now have 100% interest.

Horizon's interest in PRL5 will become 49.647% if the transaction is approved.

The PRL4 deal is subject to government approval, while PRL5 is subject to pre-emptive rights from operator and major interest holder Santos Ltd of Adelaide.

InterOil said its move will allow it to concentrate on development of its potentially huge gas discoveries at Elk-Antelope in the eastern highlands. The recent Elk-4 well flowed at 14 MMcfd. The company said the structure is potentially 13km long and 5km wide with gross reservoir thickness of 500m.

The Antelope-1 appraisal will be drilled later this year.

The company is a member of the Liquid Niugini Gas group with Merrill Lynch and Clarion Finanz AG and plans a 2-train LNG plant in Port Moresby capable of producing up to 9 million tonnes of LNG/year from 2012 using the Elk-Antelope gas as feedstock.

ExxonMobil

The major did not disclose financial details but said the transition will take place over a "multiyear period."

US motorists, however, will continue to see Exxon and Mobil-labeled outlets throughout the country. About 75% of ExxonMobil's roughly 12,000 stations in the US are owned by branded distributors. ExxonMobil will still sell gasoline to those stations and get paid for the use of its name.

Ute Energy, Anadarko joint venture

Chipeta will operate a gas processing and delivery hub in the Greater Natural Buttes area.

Ute Energy is an investment of Quantum Energy Partners, Quantum Resources Management, and the Ute Indian Tribe of the Uintah and Ouray reservation.

Anadarko is the operator and has 75% interest in Chipeta, which owns an existing 250 MMcfd refrigeration processing plant.

Chipeta is constructing a second 250 MMcfd cryogenic processing plant. It's scheduled for completion during the first quarter 2009.

Eni, Petrobras partnership

The Italian major will offer its exclusive slurry technology to convert residues and heavy oils, typical of those produced in Brazil.

Eni Chief Executive Paolo Scaroni and Josè Sergio Gabrielli, chief executive of Petrobras, signed the latest agreements at the World Petroleum Congress in Madrid. The first memorandum of understanding was signed in Brazil in

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Eric Watkins, Senior Correspondent

A victory for Colombia

Colombia's oil and gas industry doubtlessly got a shot in the arm last week when the Colombian military completed a daring raid to release some 15 hostages held by rebels of the Fuerzas Armadas Revolucionarias de Colombia (FARC).

FARC rebels have flexed their muscles a lot lately. Indeed, Colombia's 780-km Cano Limon-Covenas oil pipeline was shut down late last month after FARC guerrillas dynamited it and stopped the transport of some 100,000 b/d of oil.

But one wonders if such an attack was a sign of strength or one of weakness—like the death throes of a wild beast. Just a few months ago, Colombian authorities struck hard at FARC when they conducted a surprise raid into neighboring Ecuador.

Laptop reveals support

Colombian forces killed Raul Reyes, FARC's second most senior rebel commander. No less important, documents recovered from Reyes' captured laptop computer revealed significant support for the rebels from the governments of Venezuela and Ecuador.

In a single stroke, the Colombian government wiped out much of FARC's command structure and exposed the support it received from other Latin America nations. FARC rebels have since had little else to support them—apart from the hostages they have been holding.

Even that support now looks shaky following the government's victory last week, and that means a much more positive climate for business in the country—especially the oil and gas business.

The timing could not have been better as Colombia last week announced an auction of exploration rights to more than 100 blocks, according to a senior official of the country's hydrocarbons regulator, Agencia Nacional de Hidrocarburos (ANH).

ANH director Armando Zamora said the government will auction 100 small areas, some of which had been returned to the government, and interested companies will have until the end of August to apply for authorization to bid during the auction.

Encouraging to investors

The auction—also referred to as the Second Ordinary Round 2008—will offer mostly heavy oil blocks located in the Upper Magdalena basin, the Middle Magdalena basin, the Llanos basin, and the Putumayo basin.

A second round for several larger, heavy oil projects in the East Lanos basin is by invitation only, while the third round—the Colombian Round—launched in February includes 43 blocks in four basins: Sinu-San Jacinto, Cesar-Rancheria/Guajira, Eastern Cordillera, and the Llanos basin.

Colombia is hoping that its licensing terms will offer enough incentive for international oil companies to invest in its energy sector and help boost production to the desired levels.

Colombia needs the investment. In April Zamora said state-owned Ecopetrol aims to increase oil production to 700,000 b/d by 2015 and then to 1 million b/d by 2020 (OGJ, Apr. 7, 2008, p. 38).

Whatever may be said about the licensing terms, there can be little doubt that they will get a significant boost after last week's victory over the FARC. ✦

early 2007 (OGJ, Mar. 30, 2008, Newsletter).

Both companies will study the valorisation of the natural gas reserves recently discovered by Eni off Brazil, particularly in the Santos oil basin.

Brazil has proven oil reserves of 11.5 billion bbl and proven natural gas reserves of 320 billion cu m. Hydrocarbon production, currently 2 million b/d and about 12 billion cu m/year of natural gas, will continue to grow due to encouraging exploration results, particularly offshore.

Eni has four offshore exploration blocks in Brazil along with a 30-year concession granted in 1999 to distribute natural gas in the northwest area of São Paulo state. Over the years, Saipem and Snamprogetti have jointly contributed to the building of numerous facilities in the oil sector, such as the refineries in Belo Horizonte, Porto Alegre, and São José dos Campos and some floating production systems.

Gazprom

Under a memorandum of understanding signed in 2006, both parties are committed to jointly developing oil and gas projects in Algeria, Russia, and third countries, including probable swaps of assets and operations, with exchanges of LNG and pipeline gas, for efficiency.

"Possibilities for cooperation in the area of joint acquisition of energy assets in the territory of third countries, engineering and construction of facilities of pipeline infrastructure were considered as well," Gazprom said.

This is the first time that Gazprom has established a representative in Africa. Deputy Chairman of the Management Committee of OAO Gazprom Alexander Medvedev added that cooperation would cover all parts of the oil and gas chain across Africa, including exploration and production, processing, sales, environmental protection, and energy efficiency. He said the office would help Gazprom raise its profile in becoming a global energy company. ✦

MODELING GULF OF MEXICO LOST PRODUCTION—2

Model framework can aid decision on redevelopment

Mark J. Kaiser
David E. Dismukes
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Most of the destroyed infrastructure from the 2004 and 2005 hurricane seasons in the Gulf of Mexico were mature assets low on their production curve. The revenue stream from a destroyed asset is at the least deferred, and unless the field is redeveloped, previously economic reserves will be left in the ground.

Property owners of destroyed assets are faced with a decision: Should the asset be abandoned along with its future cash flow or should the asset be redeveloped? Mature assets are unlikely to meet the economic thresholds to support redevelopment, and in the majority of cases, these structures will be abandoned by owners.

In Part 2 of this four-part series, we develop a model framework to forecast the production and revenue streams associated with the collection of destroyed assets. The general framework of analysis is outlined along with the assumptions employed in modeling.

Model framework

To estimate the amount and value of production that a structure would have generated if it was not destroyed, a five-step procedure is applied:

Step 1. Model the structure's historic oil and gas production data.

Step 2. Forecast future production based on model curves assuming stable reservoir and investment conditions.

Step 3. Forecast future revenue based on a given hydrocarbon price deck.

Step 4. Terminate production when revenue from the structure falls below its estimated cost of operation.

Step 5. Output cumulative production and present value of the revenue stream.

STEP 1: Model production profiles

Notation

Structure s is the basic unit of analysis. Define $q_t^i(s)$ as the amount of hydrocarbon type i (i = oil, gas, BOE) produced by structure s in year t. Oil production is expressed in barrels (bbl) and includes condensate (natural gas liquids); gas production is expressed in thousand cubic feet (Mcf) and includes associated gas (oil well gas, or casinghead gas). The production stream for an asset is described by its oil, gas, and BOE vectors, denoted as: $q^o(s) = (q_1^o, q_2^o, \cdots)$, $q^g(s) = (q_1^g, q_2^g, \cdots)$, and $q^{BOE}(s) = (q_1^{BOE}, q_2^{BOE}, \cdots)$ where the ith element of each vector denotes the ith year of production.

Decline curves

Production levels exhibit a wide variety of shapes due to factors and events that are unobservable, unpredictable, or both, related to reservoir characteristics, aggregation levels, investment strategies, weather events, technical intervention, and various other conditions.

Multiple production peaks after plateau are common. Preplateau peaks may also occur if development occurred in stages or unforeseen events arose during development. The purpose of decline curves is to characterize production outside the influence of exogenous factors.

Three types of decline curves are commonly used in reservoir engineering to describe the production of a well or group of wells after plateau: exponential decline—shown in Equation 1, hyperbolic decline, given by Equation 2; and harmonic decline, shown in Equation 3. In Equations 1-3, $q_t(s)$ denotes the production rate of structure s in year t, q_o represents the initial (or peak) production rate, and d, C, and n are parameters determined from historical data.

The exponential model is probably the most frequently used method to model production profiles because of its ease of application and ability to capture basic reservoir dynamics. Hyperbolic decline models

EQUATIONS

$$q_t(s) = q_0 e^{-dt} \tag{1}$$

$$q_t(s) = \frac{q_0}{1 + Ct} \tag{2}$$

$$q_t(s) = \frac{q_0}{(1 + \frac{C}{n} q_0^{1/n} t)^n} \tag{3}$$

$$r_t(s) = q_t^o P_t^o + q_t^g P_t^g \tag{4}$$

$$T_a(s) = \min\{t \mid r_t(s) < \tau_a(s)\} \tag{5}$$

$$Q = Q(s) = \sum_{t=1}^{T_a(s)} q_t(s) \tag{6}$$

$$V = V(s) = \sum_{t=1}^{T_a(s)} \frac{r_t}{(1 + D)^t} \tag{7}$$

$$q^i(\Gamma) = \sum_s q^i(s) \tag{8}$$

$$Q^i(\Gamma) = \sum_s Q^i(s) \tag{9}$$

$$V(\Gamma) = \sum_s V(s) \tag{10}$$

Economic limit and estimation techniques

When marginal costs exceed marginal revenues and the net cash flow for a structure is negative, the operator is unlikely to continue production. Operations may be shut down temporarily or permanently, depending upon the producing status of the lease, whether oil or gas is being produced, etc.

Economic limit

The economic limit is defined as the time when the direct operating cost of the structure is equal to the income under production.[1]

The economic limit criterion is reasonable given profit-maximizing decision makers. In practice, an operator may shut-in wells before the economic limit is reached if the return on the investment does not satisfy a given threshold or the operator decides for strategic reasons to exit the region. An operator may also produce for a period of time after the economic limit is reached if it intends to perform additional drilling on the property, can postpone maintenance and workover requirements, or believes prices will increase to return the operations to profitability.

Because many structures in the Gulf of Mexico are operated in aggregate units (clusters) either on a field or lease basis, the cash flow position of an individual structure is often reviewed in terms of its incremental impact to the overhead position of the production unit. An operator may continue to produce at marginal levels at a loss simply to delay the cost of abandonment. The decision criteria an operator employs for a specific asset are ultimately unobservable to analysts outside the company, but this does not negate the use of the economic limit as a proxy for these criteria.

Estimation techniques

The economic limit of a structure can be estimated based on its operating cost or by using historical data to assess the revenue position of structures at the time they stopped producing.

Both approaches have advantages and disadvantages. With expert opinion, estimates can be performed quickly and updated relatively easily. The main advantage of historic data is that we are measuring actual outcomes that incorporate a broad set of random events. Ultimately, the two approaches are roughly similar in their level of uncertainty.

Expert opinion

The EIA provides oil and gas lease equipment and operating costs on an annual basis for domestic oil and gas production operations.[2] EIA personnel track equipment, labor, and maintenance cost, and categorize operating costs on a location and production basis. For the gulf, operating costs are estimated for 12 and 18-well slot platforms with dual completions assumed to be 50, 100, and 125 miles from shore (corresponding to water depths of 100, 300, and 600 ft, respectively). Maximum crude oil production is assumed to total 11,000 b/d and maximum associated gas production is assumed to be 40 MMcfd. Meals, maintenance, helicopter and boat transportation, communication, insurance, and administration are included in expenses; water disposal costs are not included. Table 1 provides operating cost estimates for offshore wells displayed by platform size and water depth. On a per-well basis, operating costs range from \$621,000/well to \$802,000/well.

Historical data

In the threshold level approach, the revenue of structures at the time of their abandonment is quantified relative to a set of attributes. Structures are grouped according to type (caisson, well protector, fixed platform), primary production (oil, gas), and site characteristics (water depth). Inflation-adjusted averages are computed across each categorization based on structure removals in the gulf over the past two decades.[3] We associate the economic limit of a producing structure with its category average (Table 2).

Caissons and well protectors generally support three wells or less, while fixed platforms support several wells throughout their lifetime. Near abandonment, most structures will be producing from a small set of wells. When normalized on a per well basis, there is general agreement between the expert opinion values in Table 1 and the historic data presented in Table 2.

the production drop as a fractional power of the production rate and is usually applied during the later stages of the life cycle of a well. Harmonic decline is often used to model gravity drainage or water drive mechanisms. For some fields, the production rate may not be adequately modeled using any of these function types.

Structure classification

For each structure, we fit each fluid stream (oil, gas) to each of the three model forms (exponential, harmonic, hyperbolic) using regression techniques and select the best-fit curve using the maximum R^2-value. The input to the procedure is the structure's historic production of oil and gas, and the output is the model parameters for the best-fit decline curve for each hydrocarbon stream. If the model fit for $q_t^i(s)$ has an R^2-value that exceeds 0.75, the model is considered an acceptable fit and a reasonable predictor of future production. We refer to structures that satisfy this criterion as "normal" producers.

A small number of structures have production profiles that do not yield an acceptable bestfit curve. If $R^2 < 0.75$

for the oil or gas stream, the model fit is deemed unacceptable and simplified techniques are applied to generate the forecast curve. In this case, we repeat the curve fitting procedure from the second-half of the production profile.

In other words, if a structure is T years old at the time of observation, then we model the second-half of the production history, using data beginning in year T/2. If the reduced time horizon model does not satisfy $R^2 > 0.75$, then we assume an exponential model based on the structure's historic decline rate. Structure profiles with initial $R^2 < 0.75$ are referred to as "chaotic" producers.

Structures that are early in their life cycle present a special problem, since production has probably not peaked and remains largely unknown. Forecasting lost production from early producers, say within 7 years of first production, are subject to a large amount of uncertainty.

For this subset of producers, we make a conservative estimate that production has peaked over the time horizon observed and declines following the exponential model according to a specified decline rate that is held fixed across time. Structures that are within 7 years of first production are classified as "young" producers.

"Idle" structures refer to structures that were not producing at the time of their destruction. Idle structures are unlikely to restart production or to be redeveloped at a later time. We consider any structure inactive prior to 2003 incapable of future production. Nearly a quarter of the hurricane-destroyed structures was idle in 2003.

"Uneconomic" structures are producing structures with revenue streams in 2006 that have already fallen below their estimated economic threshold. When the revenue stream generated by production falls below a structure's economic threshold, the operator will stop producing.

About 20% of the active structure set was uneconomic in 2006.

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STEP 2: Forecast future production

The model curves determined in Step 1 are used to forecast future oil and gas production for the three classes of assets identified:

- Normal producers: structures that yield best-fit oil and gas production profiles with $R^2 \geq 0.75$.
- Chaotic producers: structures that have initial best-fit production profiles with $R^2 < 0.75$.
- Young producers: structures with less than 7 years production history.

Structures that do not exhibit a reasonable model fit or are early in their life cycle are subject to a greater amount of forecasting uncertainty. These subsets of structures are therefore considered separately. For all three asset classes, the production curves $q^i(s)$ determined in Step 1 are used as the forecast model. Time is initialized to the year 2006 ($t = 1$), and for the model form and decline curve parameters determined, we step ahead year-by-year in the production forecast, yielding $q^i(s) = (q_1^i, q_2^i, \cdots)$.

The forecast is performed under the assumption of "stable reservoir and investment conditions." This is a very strong assumption and one that is frequently invoked without due caution to its impact on model results. A structure that was producing prior to the appearance of a hurricane is assumed to produce according to its historic rates after the event. We assume that the modeled production will not be altered in the future due to reservoir/production problems or additional investment (to enhance production, recover additional reserves, etc.). We control for the impact of the stability assumption on our model results by performing sensitivity analysis.

ANNUAL OPERATING COST FOR GULF STRUCTURES*

Table 1

Water depth, ft	12-slot platform	18-slot platform	Average
		Million $	
100	9.34	11.18	10.26
300	9.62	11.52	10.57
600	—	12.15	12.15

*2006 US dollars.
Source: US Energy Information Administration

AVERAGE THRESHOLD REVENUE FOR GULF STRUCTURES[1]

Table 2

Water depth, ft	Primary production[2]	Caisson[3]	Well protector	Fixed platform
			$1,000	
<100	Oil	162	152	451
	Gas	525	446	491
101-200	Oil	345	398	715
	Gas	589	692	588
>200	Oil	—	—	520
	Gas	—	—	935

[1]2006 US dollars. [2]A structure is classified as a primarily "oil" or "gas" producer depending on its cumulative GOR, expressed in cubic feet of gas per barrel of oil production. If GOR ≤5,000, the structure is considered primarily an oil producer; if GOR >5,000, the structure is considered primarily a gas producer. [3]Structures are classified according to the complexity of their support foundation. A caisson is a cylindrical or tapered pipe through which a well is drilled. A well protector is an open lattice truss template consisting of three or four legs and minimal topside equipment. Fixed platforms are large, heavy structures, consisting of four or more piles with equipment to support drilling and-or production operations.
Source: Kaiser 2008

STEP 3: Forecast future revenue

Revenue is estimated by multiplying the oil and gas production forecast by the average market hub prices in the year received.

The hydrocarbon quality (API gravity, sulfur content, etc.) and transportation expense to deliver production to market is not considered. Company oil and gas sales are primarily made in the spot market or pursuant to contracts based on spot market prices. In an attempt to reduce price risk, a company may enter into hedging transactions with respect to a portion of future production. The impact of hedging or other price risk management strategies that the owner may have employed are not considered.

Revenue in year t for structure s is computed as shown in Equation 4, where P_t^o and P_t^g represent the average oil and gas price in year t, respectively. We assume a price deck that is constant throughout the life cycle of the structure: $P_t^o = P^o$ and $P_t^g = P^g$.

The revenue forecast vector starts in the year 2006 and is denoted as: $r(s) = (r_1, r_2, r_3, \cdots)$. Five commodity price scenarios are employed: $P(I) = \{P^o = \$40/\text{bbl}, P^g = \$4/\text{Mcf}\}$; $P(II) = \{P^o = \$60/\text{bbl}, P^g = \$6/\text{Mcf}\}$; $P(III) = \{P^o = \$80/\text{bbl}, P^g = \$8/\text{Mcf}\}$; $P(IV) = \{P^o = \$100/\text{bbl}, P^g = \$10/\text{Mcf}\}$; and $P(V) = \{P^o = \$120/\text{bbl}, P^g = \$12/\text{Mcf}\}$. For each scenario, the oil and gas price is assumed constant over the life cycle of the structure.

STEP 4: Estimate abandonment time

When the production revenue generated by the asset falls below its current costs, the asset is considered uneconomic and production at the structure will cease (see sidebar). The time at which a structure is no longer commer-

BEST FIT CURVE FREQUENCY AND AVERAGE MODEL PARAMETERS

Table 3

Structure type[1]	Model type[2]	Frequency, %	Coefficients a, C	Coefficients n	Curve fit R^2	Curve fit CV
Gas	Exponential	62	0.891		0.89	0.09
	Harmonic	18	7.1E-07		0.79	0.41
	Hyperbolic	20	0.049	3.6E5	0.90	0.11
Oil	Exponential	40	0.875		0.88	0.15
	Harmonic	20	1.7E-06		0.76	0.38
	Hyperbolic	40	0.068	798	0.89	0.13

[1]Structures are classified as oil or gas producers according to their cumulative GOR measured in cubic feet per barrel. Structures with GOR ≤5,000 are classified as primarily oil producers; structures with GOR >5,000 are primarily gas producers. [2]The economic, harmonic, and hyperbolic model types are defined as follows: $q_t = q_0 e^{-dt}$ (exponential); $q_t = q_0/(1 + Ct)$ (harmonic); $q_t = q_0/(1 + \frac{C}{n} q_0^{1/n} t)$ where q_t denotes the production rate in year t, and d, C, and n are parameters determined from historical data.

NUMBER OF STRUCTURES ACCORDING TO TYPE AND MODEL SPECIFICATION

Table 4

Structure type*	Idle	Uneconomic	Normal	Young	Chaotic	Total
Oil	7	10	17	4	6	44
Gas	15	11	22	15	3	66
All	22	21	39	19	9	110

*Structures are classified as oil or gas producers according to their cumulative GOR measured in cubic feet per barrel. Structures with GOR ≤5,000 are primarily oil producers; structures with GOR >5,000 are primarily gas producers. Idle structures were not producing in 2003 and are assumed not to produce in the future. Uneconomic structures have revenue streams that fall below their economic threshold in 2006. Normal structures were fit by decline curves with $R^2 \geq 0.75$. Young structures have less than 7 years production and are forecast using exponential decline curves and assumed decline rates. Chaotic structures have initial best-fit decline curves with $R^2 < 0.75$ and are forecast from the later half of their life cycle or through exponential decline curves and historic decline rates.

cial is determined by comparing the revenue in year t, $r_t(s)$, to the economic limit of the structure, $\tau_a(s)$, yielding $T_a(s)$ as shown in Equation 5.

The value of the revenue threshold $\tau_a(s)$ is derived from empirical relations using historical data and is correlated with structure characteristics such as development type (caisson, well protector, fixed platform), primary production (oil, gas), and site characteristics (water depth).

The values of the economic limit represent category averages based on statistical analysis of over 1,500 structures removed in the Gulf of Mexico over the past two decades.[3] $T_a(s)$ determines the time—for a given production forecast, price deck, and revenue threshold—that a structure will no longer be commercial (economic). At $t = T_a(s)$, a rational operator will stop producing, which will terminate the cash flow vector: $r(s) = (r_1, r_2, \cdots, r_{T_a(s)})$.

STEP 5: Cumulative production and discounted cash flow

The cumulative production Q(s) and discounted cash flow V(s) associated with each structure is computed from 2006 (t = 1) through the time of abandonment ($t = T_a(s)$) as shown by Equations 6 and 7. In the valuation estimate, D denotes an industry-wide discount rate employed for each structure.

The choice of D has a significant impact on the value of lost production and the redevelopment decisions of operators. Each company uses its own rate to guide decisions, which may be the cost of capital, the borrowed cost of money plus the cost of dividends, the return from the least profitable investment, etc. For our purposes, since we are evaluating the aggregate value of lost production, a common discount rate is applied.

Aggregation

The final step is to aggregate the production profiles and discounted cash flow across all structures in the sample set. The model output for structure s is the forecast production profile, $q^i(s)$, cumulative production, $Q^i(s)$, and discounted cash flow, V(s). If the set of hurricane-destroyed structures is denoted Γ, aggregating across this collection yields Equations 8-10.

The cumulative oil and gas production, $Q^o(\Gamma)$ and $Q^g(\Gamma)$, and the value of production, $V(\Gamma)$, represent the primary model output.

Descriptive statistics

Three decline models were fit to each structure's oil and gas production profile and the best-fit model parameters are shown in Table 3 in terms of structure type, model function, and frequency of occurrence. The average value of the model coefficients, average model fit, and coefficient of variation are also depicted. All producing structures were modeled, including idle and uneconomic producers. The exponential decline was the most frequently applied model specification.

The number of model curves classified as idle, uneconomic, normal, young, and chaotic are shown in Table 4. Idle and uneconomic structures form the largest subset of the collection. Nearly half the destroyed structures were no longer producing or were producing at levels below their economic limit in 2006. Of the remaining structures, 39 of the 67 producers yielded reasonable model fits; 19 producers were classified as young producers; and 9 did not yield an acceptable best-fit curve.

Next week: The model's estimate of the value of production lost in the 2004-05 hurricane seasons. ✦

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2. Energy Information Administration, "Oil and gas lease equipment and operating costs 1988 through 2006," Washington, DC, June 2007. Also available: http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.html.

3. Kaiser, M.J., "Economic Limit of Offshore Structures in the GOM—Descriptive Statistics," Energy Sources B, Vol. 3, Part 2, pp. 213-224, 2008.

Iraq

Niko Resources Ltd., Calgary, began field scouting in the 846 sq km Qara Dagh block in Iraq's Kurdistan Region and sought tenders for a 500 line-km 2D seismic survey.

The budget for the year ending Mar. 31, 2009, covers the seismic program, drilling an exploration well, and bonuses required under the production-sharing contract, signed in May.

Morocco

Circle Oil PLC said a completed 3D seismic survey on the Sebou license in Morocco's Rharb basin outlined many anomalies, each of which could contain gas.

A rig is under contract to begin drilling in July 2008.

Circle Oil will soon sign an agreement with state ONHYM exercising its option to participate in the ONZ-4 well, which discovered gas in the Sebou area in August 2006. The well is to go on production shortly and will provide Circle Oil's first cash flow.

Nicaragua

Norwood Resources Ltd., Vancouver, BC, plans to test its indicated discovery wells in western Nicaragua starting around the end of July 2008 and may resume drilling later in the year.

Analysis of whole core from the Maderas Negras well has resulted in recalculation of the net hydrocarbon thickness in the Brito formation to 286 ft from 138 ft.

Meanwhile, using its own rig the company swabbed 45-47° gravity oil and gas from Brito perforations at 5,915-50 ft for 10 hr. The tested interval was previously calculated to have 30 ft of net reservoir but only 1.5 ft of net hydrocarbons.

No rates were measured, but the volumes of oil and gas recovered strongly suggest that the earlier calculation of net hydrocarbons is too conservative, the company said. The well continued to flow gas after swabbing ceased.

The company plans to swab-test nine of the remaining 10 perforated intervals using a service rig and crew from Villahermosa, Mexico.

Russia

Transmeridian Exploration Inc., Houston, and DNK LLC plan an initial work program in Gasha and Selli oil and gas fields and the Ullu Chai anticline on trend with Selli field in Piedmont Dagestan, Russia.

Initial work will include 200 sq km of 3D seismic, reentering four wells, and drilling two new wells. Transmeridian owns 50% of DNK. The fields are near the Caspian Sea northwest shore (see map, OGJ, Dec. 29, 1997, p. 29).

The fields each produced 3 million bbl of oil and 4.4 bcf of gas from 8 and 17 wells, respectively, from Cretaceous anticlinal fractured carbonates and an overlying Foraminiferal reservoir in 1957-76. Oil and gas were encountered in the shallower Tertiary Maykop section but not developed.

Louisiana

Meridian Petroleum PLC completed the $8.95 million acquisition of 60% of Rozel Energy's interests in East Lake Verret field in Assumption Parish, La., where Meridian plans to drill as many as three wells to tap proved undeveloped reserves.

Meridian became operator of the field effective July 1, 2008. East Lake Verret is producing 5 MMcfd of gas and 250 b/d of oil.

Texas

West

Approach Resources Inc., Fort Worth, sees more than 600 locations to be drilled to the Pennsylvanian Canyon formation in Ozona Northeast field, Crockett and Schleicher counties, Tex.

Approach acquired additional interest in the 41,176-acre from private J. Cleo Thompson and James Cleo Thompson Jr. LP, Dallas, and others for $12 million. Acquired was a 95% working interest in all depths below the top of the Pennsylvanian Strawn formation.

Approach, which previously owned 100% working interest above the top of Strawn, acquired 7.7 bcfe of proved and 1.7 bcfe of probable reserves, 1.5 MMcfed of net production, and 75 miles of gathering lines and compression.

Approach is reprocessing 3D seismic to help identify more drilling and completion opportunities. It sees potential in the Canyon, Strawn, and Ellenburger on the properties.

PUT RIVER—1

BP evaluates, develops North Slope reservoir

Manmath N. Panda
Petrotechnical Resources of Alaska
Anchorage

James A. Dean
Tami Wheeler
Roger Sels
BP PLC
Anchorage

Jeff Pietras
BP PLC
Houston

Drilling

BP is developing a minor sand reservoir in the Prudhoe Bay field after appraising the potential by recompleting existing wells, building 3D stochastic reservoir models, and running VIP simulations. BP began production of the southern lobe of the Putuligayuk (PUT) River in late 2006.

This article includes a brief background of the Putuligayuk (PUT) River reservoir, including geological description and production history. It's followed with an analysis of the flow simulation work undertaken to design the pattern flood at PUT River.

The concluding article (OGJ, July 28, 2008) will describe a top-down reservoir modeling process (TDRM) used to assess the impact of reservoir uncertainty on ultimate oil recovery.[1] It also presents the field implementation of the pattern flood, along with field observations.

Minor reservoirs

Minor reservoir sands, which we define as those with original oil in place (OOIP) of less than 50 million stock tank bbl (MMstb), frequently occur in or near large fields. Developing such sands when the major fields are mature offers an incentive because production facilities usually are readily available and underutilized. However, it's difficult to develop minor sands economically. The uncertainty in reservoir parameters must be fully evaluated before implementing any development plan—before any cost is incurred—since even a slight error in uncertainty assessment can make the field development program uneconomic.

The PUT River sand is a minor reservoir with four identified lobes in the Prudhoe Bay field.

The southern lobe, with an estimated OOIP of 12.6-19.2 MMstb, is the most suitable sand for development. Only a few wells can be economically justified, however, as few as one to two new wells or as many as five recompletions of existing wells. The proposed location of the new wells is critical.

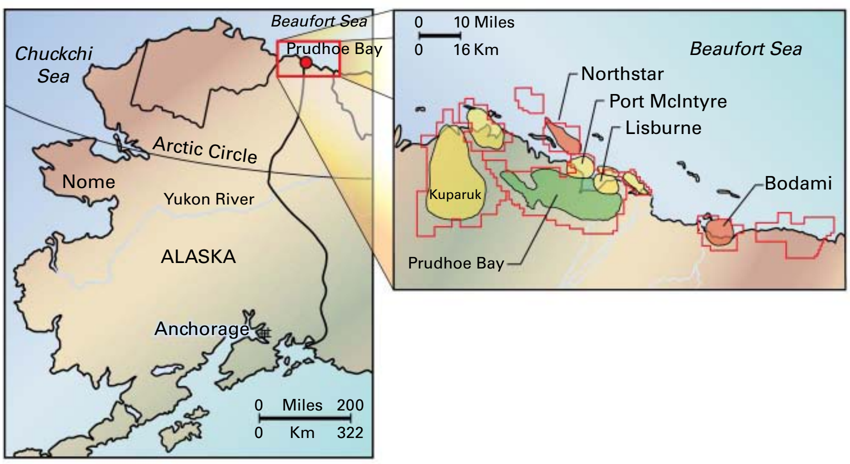
In addition to location and siting, well performance will also depend on the rock quality, structural style and its impact on fluid flow, and proper reservoir management (pressure maintenance, etc.).

To mitigate the prospect of low recovery because of the uncertainty in reservoir parameters, we developed a comprehensive reservoir analysis, including a detailed geological study

Based on a presentation to 2008 SPE Western Regional meeting, Bakersfield, Mar. 31-Apr. 2, 2008.

PRUDHOE BAY FIELD

Fig. 1

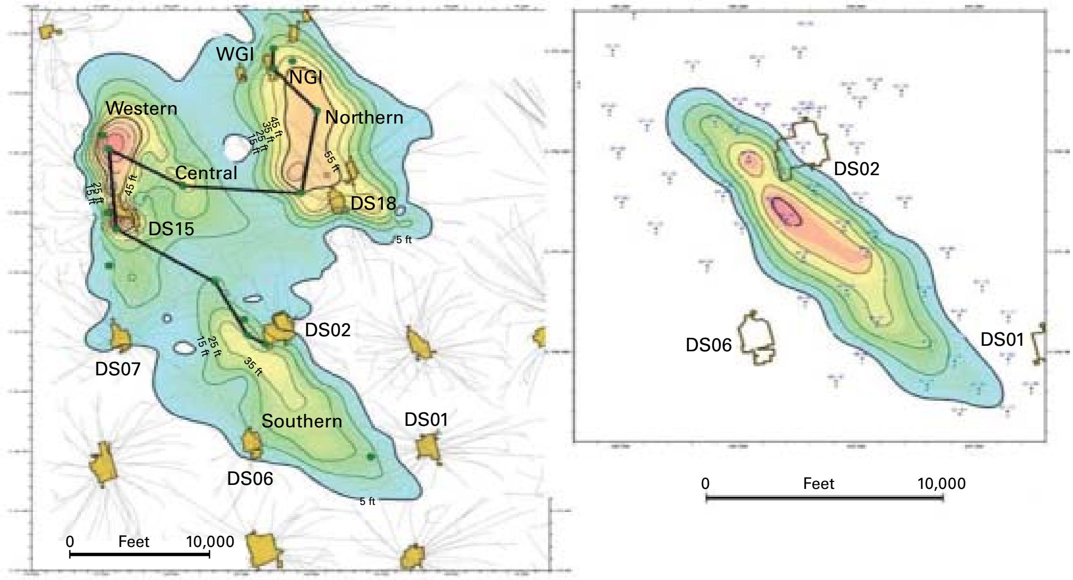


PUT RIVER SANDSTONE DISTRIBUTION

Fig. 2

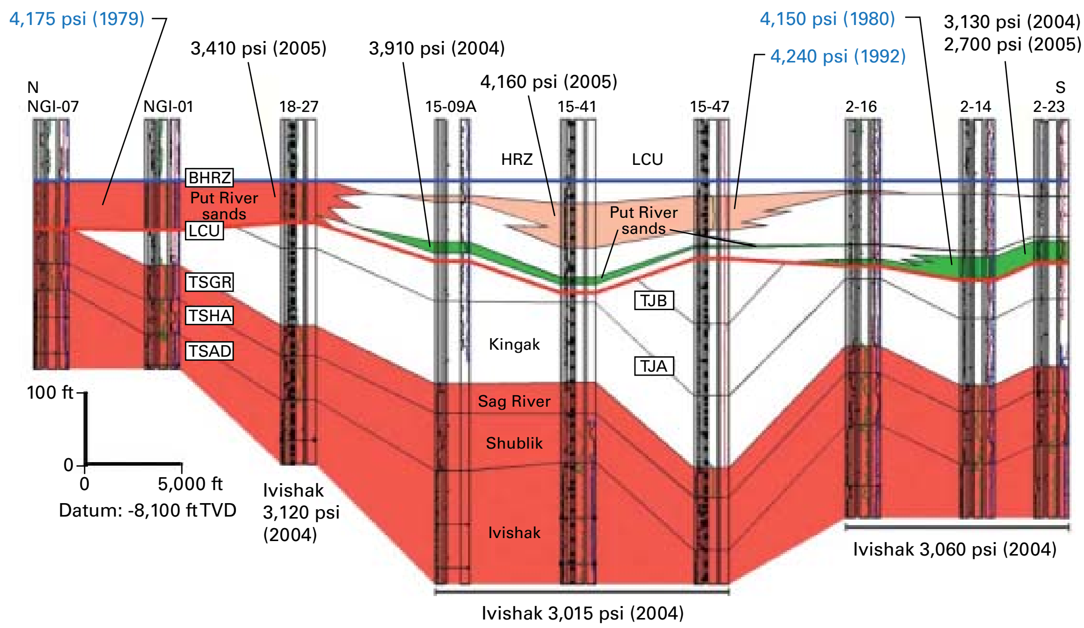
Isopach map of gross PUT River sandstone thickness. Contour interval 10 ft. Fig. 2a

Net pay map of southern lobe of PUT River sandstone. Fig. 2b



PUT RIVER STRATIGRAPHY, FLUID SUMMARY

Fig. 3



(chronostratigraphic study) to assess the paleodepositional system including sediment flow direction. This assists in positioning the new wells to optimize oil recovery. Seismic analysis helped determine the impact of faults on sand continuity.

We used the sand continuity analysis results and logs from existing wells to construct a fine scale geostatistical reservoir model, which formed the basis for numerical flow simulation. The team generated a large number of simulation models that incorporated uncertainties of major parameters.

Flow simulation using these models provided data for reservoir benefit analysis. Based on the analysis of the simulation results, we planned two producers and an injector in the PUT River reservoir with an option to add two more producers in the future.

PUT River

The PUT River sandstone is located on Alaska's North Slope within the Prudhoe Bay Unit (Fig. 1). It overlies the Kingak shale and Sadlerochit Group near drillsites 1, 2, 5, 6, 7, 15, 18, NGI, and WGI.

The PUT River sandstone, along with the Kalubik formation (shale and siltstone), is part of the PUT River interval that lies stratigraphically above the Lower Cretaceous unconformity (LCU) and below the highly radioactive zone (HRZ).

Four vertically significant and laterally extensive sandstone bodies (or lobes) have been correlated within the PUT River interval. They are termed the southern, central, western, and northern lobes of the PUT River sandstone (Fig. 2). The appraisal data indicate that the four lobes are isolated reservoirs

with different fluids and pressures.

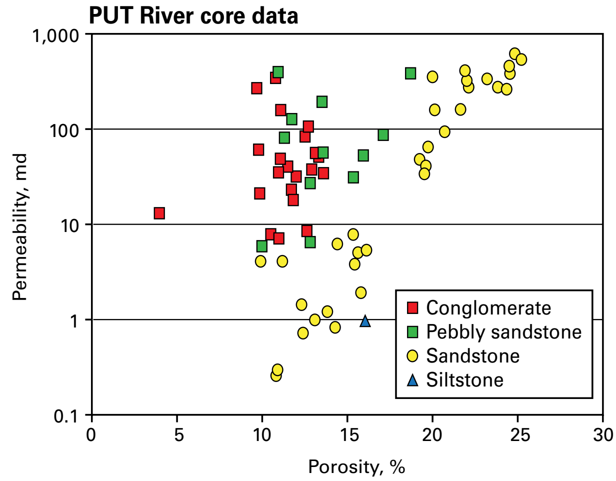
Only the southern lobe contains an undersaturated black oil accumulation. Only the southern block will be produced as a part of the PUT River development. The Northern lobe encompasses the entire PUT River interval. The remaining three lobes are stratigraphically equivalent to the Northern lobe and interbedded with the Kalubik formation.

PUT River consists of two sand packages—lower sand A and upper sand B. Sand B is up to 75 ft thick and encompasses the western lobe of the PUT River sandstone. To the south the distal portion of the B sandstone correlates to thin sandstone and siltstone beds. The Northern lobe of the PUT River sandstone consists of both the A and B sandstones.

A-sand is divided into two subsands, A2 and A4. The A2 sandstone lies directly on the LCU and is thickest in the south. The southern lobe of the PUT River sandstone entirely consists of the A2 sandstone where it is up to 41 ft thick. The A4 sandstone is separated from the A2 sandstone by a thin shale and siltstone layer. The A4 sandstone is thickest within the Midfield graben (up to 22 ft thick). The central lobe of the PUT River sandstone entirely consists of the A4 sandstone.

PUT RIVER POROSITY, PERMEABILITY CORRELATION

Fig. 4



Lithology

The sandstone in the southern lobe (subject of this article) is a medium-grained, moderately to well-sorted, chert-lithic arenite with localized pebble layers. The detrital mineralogy is predominantly quartz and chert, with minor amounts of feldspar and fine-grained lithic fragments. Glauconite occurs as disseminated and granular accumulations in concentrations up to 15%.

Clay content is largely associated with the finer-grained and poorly-sorted intervals; it is not pervasive through the matrix. Beds generally fine upward and bioturbation is common. Visible porosity ranges from 10-20% with little pervasive cementation. Quartz overgrowths occur on most grains, with quartz cement best developed in well-sorted sandstone beds. Siderite cement occurs locally mostly near the top and base of the A2 sandstone reducing the rock permeability.

Structure

The PUT River interval is bisected by the Midfield graben structure. The Midfield graben has resulted in a number of potentially isolated compartments within the field, especially in the western lobe. The northern and southern lobes are also faulted, but the vertical throw of these faults is small and likely does not result in significant reservoir compartmentalization.

Fig. 3 is a north-south oriented structural cross-section along the axis of the western and southern PUT River lobes. This

PUT RIVER SOUTHERN LOBE PRODUCTION DATA, 2-23A

Fig. 5

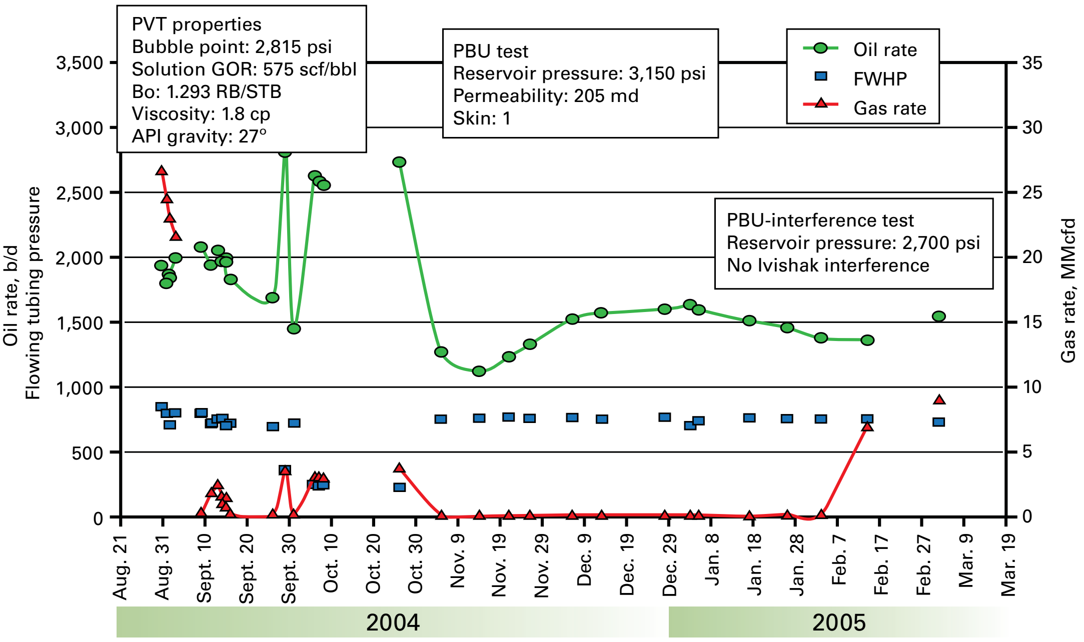


figure shows the overlying and underlying stratigraphy as well as the fault complexity of the area.

Rock, fluid properties

We used available core data and well log control to estimate the rock properties and net sandstone volume of the PUT River sandstone. Fluid properties were determined from PVT analysis of downhole and surface samples from wells 02-23A, 15-09A, 15-41B, and 18-27C.

The team estimated rock properties, including porosity, permeability, and water saturation of the A2 sandstone using a petrophysical log model calibrated to the core data from well 02-14. Fig. 4 shows the correlation between porosity and permeability for the PUT River A2 sand.

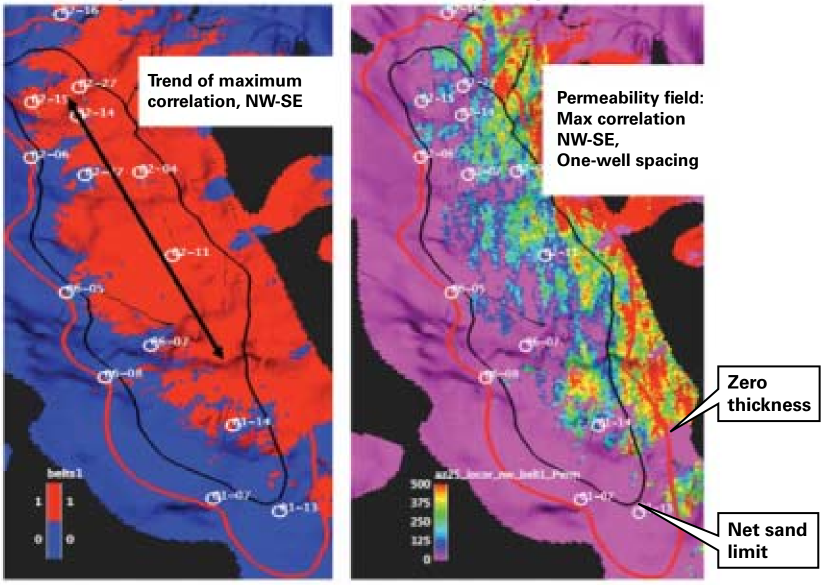
The Southern lobe contains black oil. We evaluated reservoir fluid properties using a downhole oil sample collected from well 02-23A. The bubblepoint pressure was 2,815 psia. The API gravity was 26.9° with a solution gas-oil ratio (GOR) of 548 scf/bbl. The formation volume factor was 1.293 reservoir bbl/stock-tank bbl with an oil viscosity of 1.84 cp at 3,190 psia and 181° F.

In the southern lobe, the initial reservoir pressure was 4,163 psia, based on the 1980 RFT in well 02-14. The pressure of the PUT River sandstone in this lobe has been reduced by production from the 02-27 and 02-23A wells. The current reservoir pressure is 2,710 psia, based on a March 2005 buildup test in well 02-23A. The reservoir temperature is 182° F.

The southern lobe was produced for a short period in 2005 to gather data and collect fluid samples. Fig. 5 presents the relevant production data.

PUT RIVER MODEL – FACIES, PERMEABILITY

Fig. 6



Characterization, simulation

The team modeled reservoir development options for the southern lobe of the PUT River sandstone.

We built a fine-scale reservoir model for the southern lobe of the PUT River reservoir using a geostatistical method. The general workflow to build a typical reservoir model follows an iterative process to achieve a reasonable history match.

We used log data from 14 wells to condition the reservoir properties. Fault data were obtained from the interpretation of the seismic data. Seismic data show that there are numerous mappable faults in the southern lobe. Most of the mappable faults in the main part of the lobe are small, however, except one toward the southwest edge of the lobe.

Fig. 6 shows fine-scale facies and permeability distribution obtained from the geostatistical model.

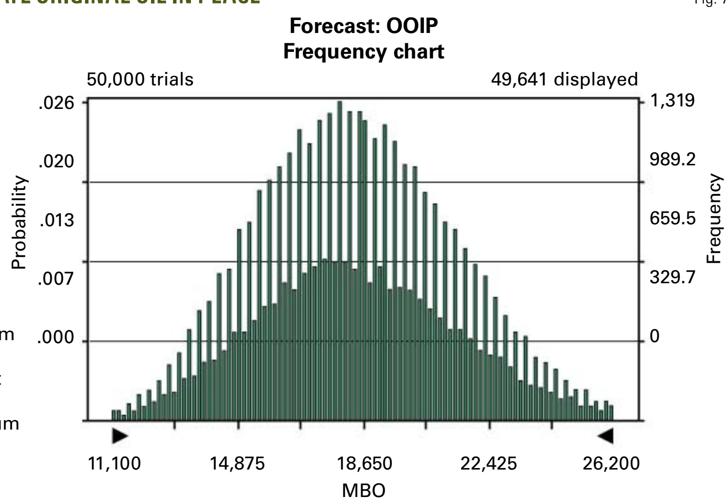
We modeled two facies: sand (facies

MONTE CARLO SIMULATION TO ESTIMATE ORIGINAL OIL IN PLACE

Fig. 7

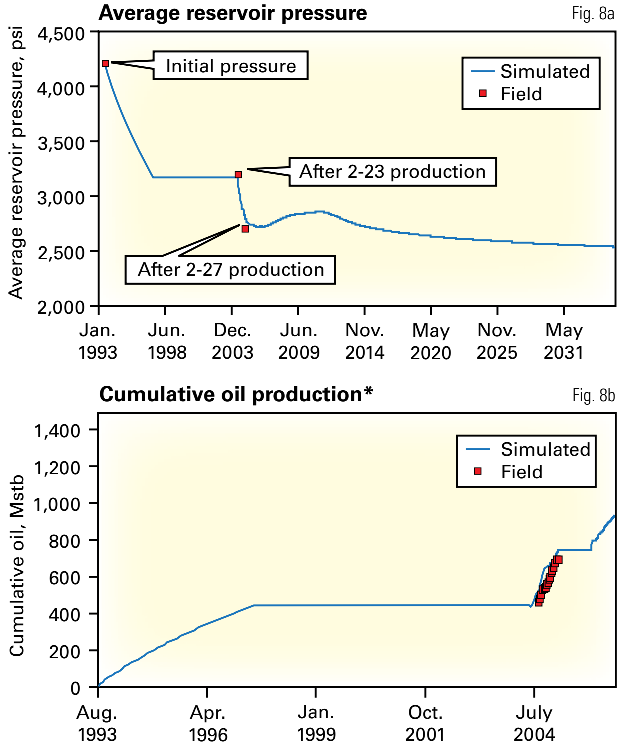
Mean inputs
Net rock volume: 26,000 acre-ft
Porosity: 19%
Water saturation: 37%
Formation volume factor:
1.293 reservoir bbl/stb

Percentile	MM bbl oil
10	14,700 - Minimum
50	18,300 - Likeliest
90	22,500 - Maximum



PUT RIVER PRODUCTION HISTORY, UPPER LOBE

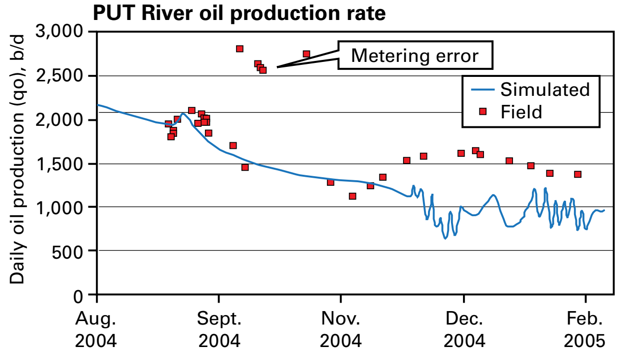
Fig. 8



*Primary production with two producing wells.

OIL PRODUCTION, 2–23A WELL

Fig. 9



1) and shale (facies 0). Facies 0 is nonproductive. Permeability and porosity have a maximum correlation in NW-SE direction. This is surmised from the analysis of deposition style of the sand in the existing wells.

A vertical trend derived from the existing well data was also used to condition the rock properties. The well data show that the midsection (~20 ft) of the sand is good quality and becomes sideritic towards the top and the bottom of the sand.

Fine-scale data were scaled up to simulation grid scale with a pressure solver. Plots of the scaled-up porosity and permeability distribution from the simulation model show that permeability and porosity decrease both westerly and downward. This trend matches the observed trend in the well data.

A Monte Carlo simulation run helped to determine the range of spread in the original oil in place (OOIP). Fig. 7 summarizes the Monte Carlo simulation output. The most likely OOIP in the southern lobe of the PUT River reservoir is 18.3 MMstb, which compares favorably with the OOIP of the geostatistical model (18.8 MMstb).

History match

The geostatistical reservoir model was used to history-match the limited field data using Landmark's VIP finite

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The authors

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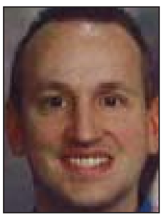

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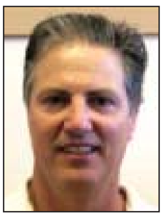

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difference simulator. The simulation model has 23 grid cells in X and Y direction and 25 layers. The grid cell dimension is about 1,000 ft in the X-direction and about 500 ft in the Y-direction. The layers are about 2 ft thick.

Relative permeability curves for Kuparuk River sands are used in the simulation run.[2] PVT data are from an oil sample from the well 2-23A.[3] We used a constant initial water saturation of 35% in the model, and set the initial pressure to 4,163 psia.

Fig. 8 displays the field average pressure and cumulative oil production match. Fig. 9 presents a comparison of oil production rates for the well 02-23A. Figs. 8 and 9 show that the simulation results match favorably with field data. Some of the variation in matching 02-23A oil rate is caused by metering error.

We also conducted a forecast run on primary oil recovery in two existing producers, 02-23A, and 02-27. The oil production rate and cumulative oil recovery data indicate that ultimate oil recovery is marginal under primary mode.

A more prudent approach to PUT River reservoir development will be to implement secondary pressure maintenance through a balanced waterflood. The target average reservoir pressure should be above the bubblepoint pressure to limit the release of solution gas from the oil in the reservoir. ✦

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Custom-designed process treats CBM produced water

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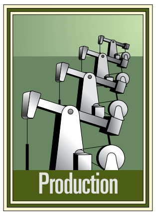

A recently completed plant in the Power River basin in Wyoming uses a new method for treating water produced from coalbed methane (CBM) wells.

The new fixed-bed dynamic flow ion exchange system provides better cost efficiency and less waste byproduct than other processes. The process has a hybrid design. It simulates all the advantages of moving resins or media beds in a fixed-bed design, and it minimizes wastes by diverting rinse portions, rather than resins or beds.

The fixed-bed design can easily cope with resin expansion associated with weak acid cation resins.

CBM water

Produced water from CBM wells has limited rapid expansion of gas production from these resources.

The coal seam waters invariably have high bicarbonate ion levels. Sodium associated with bicarbonate alkalinity poses serious environmental threats to farming and ranching. While many novel treatment processes have been promoted, ion exchange and reverse osmosis are the only technologies deployed so far.

When waste volume is the most important determinant for system costs, reverse osmosis systems have difficulty competing with ion exchange systems, even with no waste minimization techniques, for waters with less than 5,000-ppm total dissolved solids (TDS).

Table 1 briefly compares reverse osmosis, ion exchange, and electrochemical processes during treatment of water characterized by the analysis in Table 2.

Sodium removal with ion exchange is an established technology. The technology, however, traditionally produces large volumes of regeneration waste, making disposal cost prohibitive and ultimately affecting the CBM well operating costs. Hence, the industry has had limited success in the Wyoming region with ion exchange systems not designed to minimize regeneration waste.

Low waste ion exchange systems have a history in the nuclear and sugar processing industries. While a significant improvement over conventional ion exchange systems, these systems are not optimized for CBM water. Much higher cost savings are achieved by a process specifically designed for water with this signature characteristic.

Alkalinity associated cations (as in sodium bicarbonate) can be removed with very high capacities with a weak acid cation (WAC) ion exchange resin. The carboxylic acid functionality of this resin only targets the alkalinity associated sodium, aiming

Water constituents

Table 1

Constituent as ppm ion	Influent	Effluent
HCO_3	~2,600	~400
Na	~900	~150
Cl	~30	~30
SO_4	<5	~50
Ca	~30	<2
Mg	~15	<5
K	~15	<5
Other metals	<1	<1

Reactions

SAC: $R_{H+} + NaHCO_3 + NaCl = R_{Na+} + H_2O + HCl + CO_2$

WAC: $R_{H+} + NaHCO_3 + NaCl = R_{Na+} + H_2O + CO_2 + NaCl$

Treatment system comparison

Table 2

Parameter	Reverse osmosis	Conventional ion exchange	Fixed bed dynamic flow ion exchange	ED/CDT
Waste volume, %	10	9	0.5-1.0	1
Power consumption, kw-hr	2,500	365	365	5,500
Media replacement	15% of capital cost every 3 years	<5% of equipment cost every 5 years	<5% of equipment cost every 5 years	35% of equipment cost every 3-5 years
Chemical consumption	Acid, biotreat	Acid	Acid	Acid
Sensitivity to solids	High	Low	Low	High

to neutralize the alkalinity.

As a result, the process produces effluent water with a pH that can be directly discharged without any adjustment.

By contrast, most ion exchange systems (if not all) currently deployed in the CBM field use strong acid cation (SAC) resins, which have lower operating capacities and require 100-200% stoichiometric excess of acid to regenerate. (See reactions box.)

While capacities of SAC resins are enhanced in the alkalinity neutralization function, they still do not match the high capacities or near stoichiometric acid requirements of WAC resins. WAC resins, however, have characteristics that make the system design very special.

The benefits of WACs include high capacity, virtually 100% acid utilization resulting in no acid wasted, effluent pH within discharge limits.

A negative is that WACs expand 80-90% upon exhaustion.

With high bicarbonate-level associated sodium, the most efficient means to remove sodium is with a weak acid cation resin, regenerated with sulfuric acid. The existing technologies minimize waste with what may be called dynamic system design. Either the resin or the resin bed is moved to optimize rinsing cycles. Such systems would need to be redesigned to cope with large variations in the resin volume or density, thus they currently use strong acid cation resins.

This single design limitation forces the forfeiting of 50% or more of maximum possible capacity from a volume of resin. Additionally, strong acid resins require stoichiometric excess of 100-200% acid for regeneration, producing an acidic waste, requiring neutralization.

The CBM water-treatment plant currently has a 30,000-b/d capacity. In the foreground is the inlet pond (Fig. 1).

The treatment processes includes three storage tanks for breaking the regeneration cycle into segments (Fig. 2).

Custom designed system

After successfully passing the Wyoming Department of Environmental Quality water quality tests, RG Global's Catalyx Fluid Solutions division recently launched commercial production of its first plant employing the patent pending fixed-bed dynamic flow ion exchange system specifically designed to treat discharge water from coalbed methane wells.

The multimillion dollar plant, the first phase of three phases and part of a 5-year, $20-22 million gross revenue build-own-and-operate contract with Yates Petroleum Corp., currently has a capacity to treat 30,000 b/d of coalbed water and can be operated continuously at 120% of capacity (Fig. 1).

Located about 35 miles west of Gillette, Wyo., in the Powder River basin,

The plant aims for the discharged water to have sodium levels close to existing levels in the river (Fig. 3).

the plant employs the new proprietary ion exchange technology to clean the water more cost efficiently and with less waste byproduct than other methods currently in use.

It incorporates the following design steps that enable the system to produce a small, concentrated regenerant:

- System first utilizes an aluminosilicate (zeolite) filtration media as a prefiltration step. The use of a mineral instead of multimedia filters removes dissolved iron, which is fluffed off during backwash, when air is used for scouring.
- The first-stage ion exchange unit is a countercurrent, upflow packed-bed system with 100% freeboard at start of service cycle. Upflow service eliminates any gas pockets formed due to bicarbonate conversion to CO_2.
- When the sodium bicarbonate levels are high, the CO_2-generated by the first stage is followed by a degasification step.
- The degasification step is followed by a second-stage unit identical to the first stage.
- A final degasifier eliminates CO_2 formed during the second stage, and water is then discharged.

The fixed-bed dynamic flow ion exchange system occupies about 2,000 sq ft of floor space for every 30,000 b/d capacity plant.

Waste minimization

The primary advantage of the process is evident during the regeneration procedure. The processe uses three storage tanks to break the regeneration cycle into segments (Fig. 2).

The first cycle consists of pumping a premixed acid volume through the resin bed, in a counter current manner.

During the first cycle, the process water from the columns is diverted to the feed pond.

The concentrated acid is completely adsorbed by the resin, producing a rich stream of sodium sulfate.

The second cycle pumps rinse water from a second tank and starts rinsing the resin. This rinse is saved in the tank used for pre-mixing acid for the next regeneration cycle.

The third cycle pumps rinse water from a third tank and further rinses the resin. This rinse is saved in the tank used for the first rinse in the next regeneration cycle.

The fourth cycle takes treated water and rinses the resin completely, and the water is saved in the tank used for the second rinse in the next regeneration cycle.

The waste produced from the regeneration is typically equivalent to less than one bed volume of resin. Given that the resin has two to three times the capacity of strong acid cation resins, the already low regenerant volume helps further reduce the waste per barrel.

Sulfuric acid advantages

The process uses sulfuric acid as a proton source that will allow the operators to eliminate completely liquid-waste discharge from the site.

Currently under way at the project is implementation of Stage Two that includes installing a system for varying the temperature of the very low volume of waste and crystallizing sodium sulfate decahydrate or anhydrous sodium sulfate.

This resulting product can be sold to industries as industrial grade raw material.

No chlorides

The recently installed plant has a 30,000-b/d capacity and can operate 24 hr with remote web-based controls. The use of sulfuric acid further helps meet upcoming stringent chloride limits in the Powder River basin.

Hydrochloric acid use for ion exchange regeneration by other systems may produce leakage of chlorides that may not meet discharge standards.

Minimal environmental impact

The fixed-bed dynamic flow ion exchange system was designed for long-term large-scale implementation. Average electrical conductivity in the Powder River is 1,900 µsec/cm. Discharging large volumes of water into the river can affect the overall salinity of the river. There are concerns from wildlife conservation specialists that certain organisms have evolved to exist in this level of sodium and salinity. If the produced CBM water is purified beyond the levels of sodium in the river, it is postulated such wildlife would be affected adversely.

As shown in Table 2, sodium bicarbonate dominates the water analysis; hence, a sodium-removal approach on the entire stream would desalinate the water beyond the required as well as desired amounts. It was important, therefore, to design the plant with an automated, proportionally controlled blending valve. The process aims to discharge water with sodium levels close to existing levels in the river. This approach has two benefits:

- It reduces the total water volume treated, thereby improving treatment economics.
- Within the next year, when more than 120,000 b/d will be discharged into the river, the overall sodium level in the river will not be disturbed.

Fig. 3 shows an operator taking a sample of the water effluent. ✦

The author

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Changing feed conditions push Egyptian gas plant to upgrade CO_2 membrane system

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Gas Processing

Changing feed operating conditions at Khalda Petroleum Co.'s Salam gas processing plant in Egypt's Western Desert led the company to make changes to its membrane system for removing CO_2.

The plant's feed operating conditions had changed over time. An increase in feed flow rate and feed CO_2 content combined with membrane permeability variations—due to natural membrane aging and use—required adjustment in system operating conditions to fulfill KPC targets of maximizing system hydrocarbon recovery and meeting acceptable CO_2 sales-gas specification.

This article will present the flexibility of membrane systems when such changes occur and describe how performance of a two-membrane-stage system was optimized.

Membrane concept

Total worldwide production of natural gas is about 103.8 tcf/year.[1] All of this gas requires some treatment, and about 20% requires extensive treatment before it can be delivered to the pipeline. As a result, several billion dollars' worth of natural gas separation equipment is installed annually worldwide. The membrane market share is about 2%, essentially all for CO_2 removal.[2]

This fraction will likely increase because other applications of membranes in the natural gas processing industry are under development.[2] [3] Membranes can be used to separate other gaseous components such as H_2S, N_2, He, and water vapor from nonassociated or associated gas stream under a partial pressure differential.[4] Table 1 shows typical membrane materials that can be used to separate the impurities from natural gas.[2]

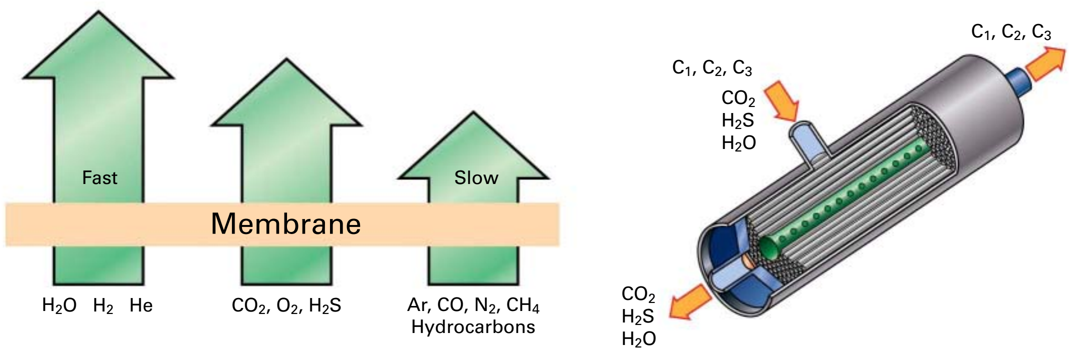
Removal of CO_2 is the only membrane-based natural gas separation process currently practiced on a large scale; more than 200 plants have been installed. The membrane system operates on the principles of selective permeation.[5 6]

Certain gases permeate or pass through the membrane more easily than others (Fig. 1). This allows the more rapidly permeating (fast) components to be collected in one stream and the slower permeating

MEMBRANE MATERIAL FOR SEPARATING IMPURITIES FROM NATURAL GAS — Table 1

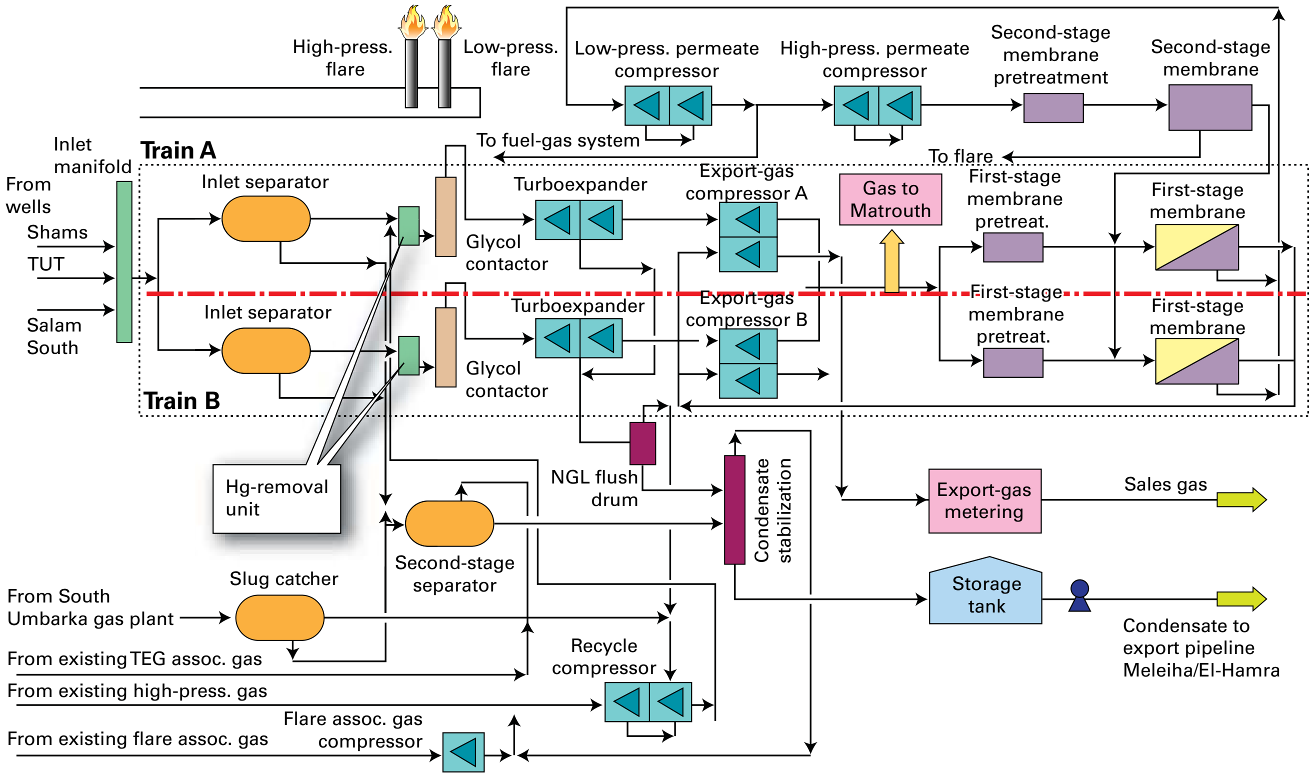
Typical polymer used	Category of preferred polymer material	Component to be permeated
Cellulose acetate, polyimide	Glass	CO_2
Cellulose acetate, ether-amide block copolymer	Glass and rubber	H_2S
Polyimide, perfluor polymers	Glass	N_2
Many	Glass and rubber	Water vapor

THIN SEMIPERMEABLE BARRIERS — Fig. 1



Salam process flow

Fig. 2



(slow) components to be collected in a second stream. In natural gas treating, CO_2, hydrogen, helium, H_2S, and water vapor are highly permeable gases, sometimes characterized as "fast" gas molecules that permeate to a greater extent across the membrane to the lower pressure side than do the "slower" gases (i.e., hydrocarbons).

The permeate gas will have a higher concentration of the fast gases and a lower concentration of the slow gases, relative to the feed. The gas that remains on the higher pressure side, also called the residual gas, will be depleted in the fast gas components relative to the feed gas.

The driving force for permeation is the difference in partial pressure of a given component between the feed (high pressure) side and the permeate (low pressure) side of the membrane. The greater the partial-pressure difference, the greater the driving force.[6]

A simple mathematical representation (accompanying equation box) can illustrate gas transport across a membrane.[6] The permeability coefficient, K, is a function of both the solubility and the diffusivity of the gas in the polymer matrix. Several mathematical models are available that derive the permeability coefficients.[7 8]

Membranes have two performance characteristics that determine methane product recovery and purity: permeation rate and selectivity.

Permeation rate or flux is the rate at which a gaseous component can diffuse through the membrane medium to the low-pressure side. The rate of permeation for each component is determined by the following:

- The characteristics of the component.
- The characteristics of the membrane.
- The partial pressure differential of the gaseous component across the membrane.

Since the permeation rate for CO_2 is greater than for methane, increased flux through the membrane will increase the methane product purity, but decrease the methane recovery in the residual gas stream. Selectivity refers to the ratio of the permeation rates of a fast gas (CO_2) and a slow gas (methane or other hydrocarbon). The selectivity of CO_2 to methane determines the efficiency of the separation and the methane recovery.

Equation

$$\nu = KA(P_1 - P_2)$$

where:

- ν Volume of permeated gas, scf/hr
- K Permeability coefficient of permeating gas, ft/(hr-psi)
- A Membrane surface area, sq ft
- P_1 Partial pressure of feed stream, psi
- P_2 Partial pressure of permeate stream, psi

Salam gas plant

Khalda Western Desert gas development project at Salam is 70 km from Matrouh. The plant processes gas condensate from Salam field, Qasr field,

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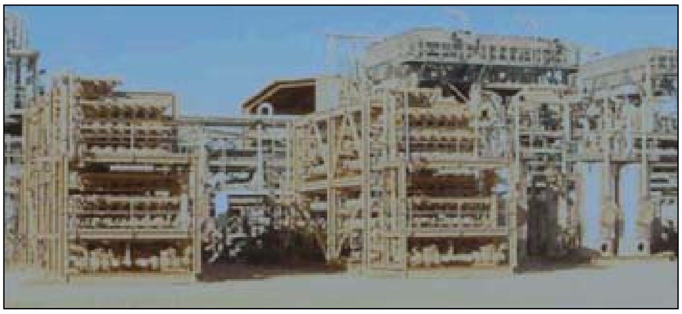
South Umbarka, and an oil plant's associated gas. The project produces about 200 MMscfd of export gas at an export pressure of 101 bara and 9,000 stock tank bbl (stb) of condensate. The plant started up in July 1999.

The sales gas is designed to have a maximum CO_2 content of 3% mol, a maximum H_2S content of 4 ppm (vol), a gross heating value greater than 1,040 btu/scf, a water dewpoint of less than 0.0° C. at 71 bara, and a cricondentherm of 5° C. The condensate is designed to have a maximum of 11 psi rvp.

The flow diagram of the Salam gas plant (Fig. 2) shows gas flowing from the wells into two parallel trains. First it enters a three-phase separator where the main water-condensate-gas separation takes place. Gas from the three-phase separator goes to the mercury-removal unit. Then it flows to the glycol contactors to remove water from the gas to avoid hydrate formation and to achieve water-content specifications.

Gas is then diverted to the dewpointing package, whose function is to separate entrained traces of condensate and heavier hydrocarbons that condense as liquids from the gas at lower temperatures. This step achieves hydrocarbon dewpoint specifications using turboexpander technology.



Salam gas plant in Egypt's Western desert employs a membrane CO_2-removal system (Fig. 3).

After dewpointing, the gas enters the gas-sweetening system (two-stage membrane package) to reduce CO_2 in the export gas. The final step is to export the gas via the export compressors.

Condensate collected from the various processing steps moves to stabilization before being stored in the three storage tanks. The stabilizer tower removes the light hydrocarbons to avoid release in the tanks and to achieve the rvp specification. Condensate is then shipped from the storage tanks via shipping pumps to El-Hamra.

Membrane system

The membrane system at the Salam gas plant had been started up in July 1999 (Fig. 3) and has operated successfully and without major upsets or membrane replacement. It includes two membrane stages. Each stage contains a pretreatment unit and membrane skids. Each pretreatment unit consists of a filter coalescer, a guard bed, and a particle filter. Each membrane skid consists of membrane tubes containing membrane elements.

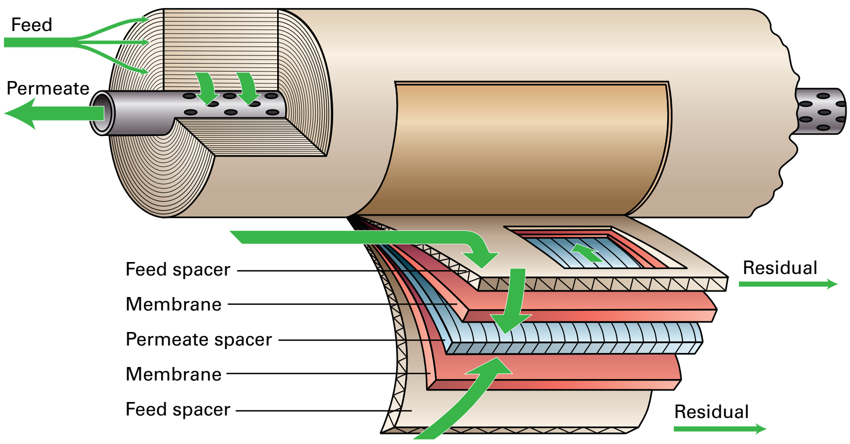
These elements consist of cellulose acetate membrane sheets that are bound onto a woven cloth support. A membrane sheet has two layers: a relatively thick microporous layer that is in contact with the cloth support and a thin active layer on top of the microporous layer.

A membrane element is a spiral-wound assembly with a perforated permeate tube at its center (Fig. 4). One or more membrane leaves are wrapped around the permeate tube. Each leaf contains two membrane-cloth composite layers that are separated by a rigid, porous, fluid-conductive permeate channel spacer. These leaves are separated from each other by a high-pressure channel spacer. The membrane leaves are sealed with an adhesive on three sides; the fourth side is open to the permeate tube.[6]

During the sweetening process, the feed gas from the turboexpander is compressed through the first-stage export compressors. The feed gas is then delivered to the pretreatment section of the membrane unit that provides key protection for the membrane elements and keeps membrane feed dry and free of contaminants. The gas first passes through a high-efficiency filter coalescer for removal of entrained contaminants such as sand, pipe scale, lubricating oil, and hydrocarbon, or water condensate. The filtered gas then passes through a guard bed to remove trace contaminants and is then sent through a particle filter to remove any entrained dust or particulates from the guard bed.

After exiting the pretreatment section, the feed gas combines with the recycle gas from the second-stage membrane before entering the first-stage membrane skids (Figs. 2 and 5).

SPIRAL-WOUND MEMBRANE ELEMENTS* — Fig. 4



*Two membrane sheets with permeate spacer between; leaves are separated by feed spacers and wrapped around a permeate tube facing it with three open ends.

Impact of operating parameters on membrane performance

Table 2

Operating parameters change / Impact on membrane performance:	First or second stage*				
	Membrane areas ↑	Feed gas temperature ↑	Feed gas pressure ↑	Permeate pressure ↓	Membrane replacement ↑
Sales gas CO_2 content	↓	↓	↓	↓	↓
Hydrocarbon recovery (assuming an unlimited permeate compressor capacity)	↓	↓	↑	↑	↑

*Increase = ↑; decrease = ↓.

This combined stream has a design CO_2 content of 6.34% mol and is the feed gas to the first-stage membrane skids.

As the feed gas passes through the membrane tubes, the gas is separated into a high-pressure methane-rich gas (residual), and a low-pressure gas stream concentrated in carbon dioxide (permeate).

The first membrane stage is designed to produce a residual gas (sales gas) with 3% mol CO_2 content, which is supplied to the export compressors for gas metering. The permeate gas containing 30% mol CO_2 is compressed through the permeate compressor and then directed to the second stage membrane package.

The second membrane stage is designed to recover most of the hydrocarbons from the first-stage permeate gas. The second membrane stage residual gas is recycled back to the first membrane stage. The second-stage permeate gas containing 71% mol CO_2 is flared.

Membrane operational flexibility

With time, plant operating conditions at the Salam gas plant have changed:

- The feed gas CO_2 concentration increased from 6.34% mol to 8.5% mol.
- The feed flow to the plant increased from 206 MMscfd up to 235 MMscfd.

This resulted, in August 2007 after 8 years of operation, in a CO_2 concentration increase in the sales gas up to 4.7% mol from the designed 3% mol and an increase in sales-gas flow rate to 210 MMscfd from 200 MMscfd.

This observation is in line with the well-known principles of membrane systems. For traditional solvent-based CO_2-removal technologies, unit size is mainly driven by the absolute amount of CO_2 to remove. Membrane systems, however, are CO_2 bulk-removal technologies for which unit size is mainly driven by the percentage of CO_2 removal. A given membrane system designed to reduce CO_2 down to 3% mol from 6% mol (=50% CO_2 removal) will also be able to handle a gas containing 8% and produce a gas with 4% mol, all other conditions remaining constant (feed-gas flow, pressure, temperature, so forth).[5]

Moreover, membrane systems are modular and can easily cope with increase of feed flow rate. An increase of feed flow rate requires a proportional increase in membrane area requirements. If the membrane area is fixed, an increase in feed flow will result in an increase of CO_2 in the produced gas.

Next to the changes in feed-gas conditions (flow and composition), normal membrane aging can result in a CO_2 concentration increase in the sales gas. Membranes are subjected to a lifetime that varies with feed-gas conditions, membrane pretreatment design, and operator skills. Salam gas plant has shown excellent performance with membrane lifetime of more than 8 years.

Design of a membrane system takes into account the natural performance decline (membrane aging) by sizing the system for end-of-life conditions, so that the system will always reach the required specifications. During the lifetime of the membrane, the system will require minor operational adjustments as the membrane properties (selectivity and permeability) vary.

This article will further describe how the Salam gas plant has been operated as feed-gas conditions have changed and as membranes have aged, keeping in mind KPC's objectives of producing gas with an acceptable CO_2 content while minimizing hydrocarbon losses that translates directly in sales gas volume and revenue.

Adjustment to changes

Several operating parameters affect gas separation by membrane, including feed-gas flow and composition, pressure differential across the membrane, gas temperature, online membrane area, and sales-gas specification. A good understanding of the effects of these process parameters is important to maximize the efficiency of the operation.

When conditions are changing, plant operation needs to be reassessed in order to find a new optimum operating mode in term of sales-gas specification and hydrocarbon recovery (directly related to sales-gas volume and revenue). For the two-membrane-stages system at Salam gas plant, not only the two individual membrane stages' performance has been reassessed, but also the overall system including recycling step from the second to the first membrane stage.

The following parameters, individually or combined, can be used to optimize plant operation in order to cope with the changes in feed conditions and the natural membrane aging:

- Membrane area of first and second membrane stage.
- Temperature of first and second membrane stage feed gas.
- Pressure of first and second membrane stage feed gas.
- Pressure of first and second membrane stage permeate gas.
- Replacement of those membranes that have reached the ends of lives, in first or second membrane stage.

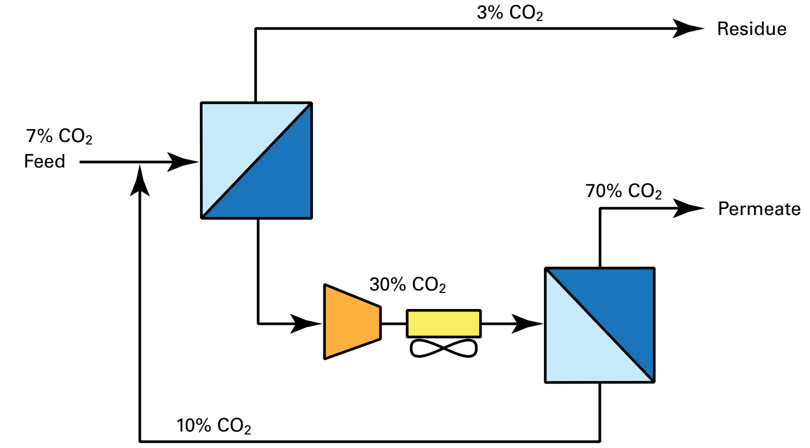
Table 2 illustrates the qualitative impact of the operating parameters on the overall two-stage membrane system. The impact, in absolute terms, of each of these parameters will vary. In combinations of different parameters, therefore, each of them will weigh more or less on the overall performance. Note that other factors, such as permeate compressor capacity limitations, need to be taken into account as well.

Table 2 shows that the following parameter adjustments always have a positive effect, both on sales-gas CO_2 content (decreased) and on hydrocarbon recovery (increase): feed pressure increase, permeate pressure decrease, as well as membrane replacement.

The following describes the impact of the operating parameters, independently.

MEMBRANE SYSTEM

Fig. 5



First, second-stage area

With an increase in the first-membrane stage area, the unit can handle a constant feed flow rate and produce sales gas with a lower CO_2 concentration or can handle a higher feed flow rate producing sales gas with the same CO_2 concentration.

In the former case, the throughput feed gas to the second membrane stage will increase. If the permeate compressor capacity is not limited, a higher flow richer in CO_2 will be recycled back to the first membrane stage. The second-stage permeate gas flow rate will slightly increase. (Hydrocarbon losses increase as a lower sales-gas CO_2 spec is reached.)

An increase in second-membrane-stage area will result in a second-stage residue with a lower CO_2 concentration and thus also a lower CO_2 concentration in the first membrane-stage feed gas and in the sales gas. A higher membrane area will allow not only a higher CO_2 permeation flow but also a higher methane permeation flow and thus an absolute increase in vented hydrocarbons.

First, second-stage feed temp.

The permeability of gases generally increases with increasing temperature. The permeability for carbon dioxide, however, increases at a lower rate than methane and other hydrocarbons with an increasing temperature. This means that selectivity for carbon dioxide over methane decreases as the operating temperature increases. Consequently, methane-product recovery (hydrocarbon recovery) will decrease, while purity (sales-gas CO_2 content) will increase as the operating temperature increases, all other operating conditions being constant.

First, second-stage feed pressure

The increased pressure creates a greater driving force across the membrane and results in a net increase in permeation through the membrane.[6] The membrane area requirement therefore drops or, for a fixed membrane area, a lower CO_2 concentration in the sales gas/recycle stream will be reached.

First, second-stage permeate pressure

A decrease in permeate pressure increases the driving force across the membrane and results in a net increase in permeation through the membrane. The membrane area requirement therefore drops or, for a fixed membrane area, a lower CO_2 concentration in the sales gas will be reached. On the other hand, a lower amount of hydrocarbons will permeate, which translates in a higher hydrocarbon recovery.

A decrease of the second-membrane-stage permeate pressure will result in a decrease in amount of hydrocarbon permeating through the second membrane stage and thus in a better overall hydrocarbon recovery.

First, second-stage replacement

An aging membrane element can show declining selectivity. This means that more methane permeates at a fixed CO_2 permeation. Consequently, more hydrocarbons are lost, and the load on the permeate compressor (in the case of a first-membrane-stage decline) increases. Therefore, a membrane at its end of life will need to be replaced.

Membrane systems are built modularly and systems can thus be easily and partially isolated. After replacement of a high number of membrane elements, a step change in plant performance becomes apparent:

• An increased selectivity of the first-stage membranes translates in a lower permeate compressor load.

• An increased CO_2 permeation rate permits reduction in the first-stage membrane area or an increase in the first-stage permeate pressure.

• An increased selectivity of the second membrane stage translates into a lower hydrocarbon content in the vented second-stage permeate gas and thus a higher hydrocarbon recovery. It also leads to a lower CO_2 concentration in the recycle stream; this also results in a lower CO_2 content in the sales gas.

In conclusion, a (partial) membrane replacement effort is completed only after the operating parameters of the membrane system are fine tuned in order to reach the correct sales-gas specification, while maximizing the hydrocarbon recovery.

Adjustment to operational changes

The following parameters have been tested at Salam gas plant in order to cope with the changing feed conditions (CO_2 content and flow increase) as well as with the normal aging of the membranes:

• In August 2006, the second-membrane-stage area was increased by 20%. This resulted in a decrease of the CO_2 content in the sales gas. In the first membrane stage, an increase of membrane area has not been envisioned.

• To determine the optimum second-membrane-stage operating temperature, operators gradually increased the feed temperature of the second membrane stage with continual monitoring of CO_2 content in the second-stage permeate gas and in the sales gas. As expected, it was found that with an increase in the feed temperature of the second membrane stage, the CO_2 concentration in the second stage residue gas decreased and with it the CO_2 concentration in the feed gas to the first membrane stage. But also observed was that the amount of hydrocarbons lost through the second membrane stage permeate increased.

Increasing feed-gas temperature in the first membrane stage hasn't been implemented at Salam gas plant due to permeate compressor capacity limitation and the objective to maximize hydrocarbon recovery.

• In 2007-08, membrane elements have been replaced in both the first and second stages. Replacement of the membrane elements in the second stage did result in a significant decrease of the CO_2 content in the sales gas to 3.8% mol from 4.7% mol. First stage membrane replacement is still under evaluation.

• The deeper CO_2 cut (to 3.8% from 8.5% compared with design of 3% from 6.34%) has resulted in a higher load on the permeate compressor. Excess first-stage permeate (exceeding the compressor capacity) is flared and results in additional hydrocarbon losses.

• In terms of permeate pressure, design plant operating conditions are based on the lowest possible permeate pressure. A temporary increase of 80% of the permeate pressure has been tested on the second stage, resulting in a significant increase in hydrocarbon losses.

• Feed pressure increase has not been tested at Salam gas plant.

Acknowledgment

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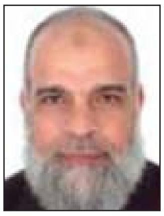

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US NATURAL GAS—Conclusion

Plans to add storage along US gulf threaten possibility of overbuild

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Golden, Colo.

Pipelines

Currently planned storage capacity increases in the Southeast US-Gulf Coast region would add nearly 30% to working-gas storage capacity and have an even greater effect on withdrawal capacity.

Thirty-one storage projects have been announced for 2008-10 in the Southeast US-Gulf Coast region; adding 304.9 bcf of working-gas capacity and 17.5 bcfd of withdrawal capacity (Table 1). The increased withdrawal capacity spreads across four states, with Louisiana receiving 29% of the increase, Texas 28%, Mississippi 27%, and Alabama 16%.

Part 1 of this article (OGJ, July 7, 2008, p. 74) examined the basis shifts already under way and expected as a result of ongoing pipeline construction in the Texas Gulf Coast. This concluding article reviews each announced storage facility, examines the possibility of overbuild, and summarizes the most likely storage development scenario for the Southeast US-Gulf Coast.

Fig. 1 shows the timing of new storage deliverability additions (new withdrawal capacity). Completion of an initial group of projects should occur during 2008. Construction of most of these facilities has been under way for months or years (shown in blue as most likely to be completed). Increases in storage development costs, various permitting problems, and a reduction of natural gas' forward summer-winter differential will likely result in delay of some projects into 2009.

The less likely to be completed group of facilities shown in Fig. 1, currently scheduled for completion in 2009-10, will be subject to a continuation of the factors delaying some of the 2008 projects. These later projects also must overcome two key factors increasing the risk of storage development in the region:

- The development and promotion of many of them was based on service as a sink for surplus LNG expected to arrive at new and existing terminals in vast quantities during the summer season, when the global supply-demand balance would push surplus cargoes to the US. Recent developments in the LNG market suggest this LNG supply-push scenario is unlikely to develop in the near term, resulting in a decrease in LNG imports over the next 1-2 years. Absent the driver of LNG storage injections, the economics of storage development in 2009-10 may suffer.
- Financial investors and storage developers are backing many of the storage projects, rather than traditional storage players such as LDCs or utilities. These new market participants evaluate storage projects through rate-of-return, rather than as support for an underlying business. As any development problems and economic issues become recognized in the market, these financial players will likely cut their losses.

The market for facilities in the development stage may also quickly become glutted, resulting in reduced storage values and a deterioration of the environment for new storage construction.

Overbuild possibility

Completing all of these projects would lead to a nearly 30% increase in regional working-gas storage capacity.[1] The buildup of so much new withdrawal capacity, however, would stand as the more important consequence.

Louisiana will host 5.1 bcfd of new,

SOUTHEAST US-GULF COAST GAS STORAGE PROJECTS Table 1

Location	Storage capacity, bcf 2008	2009	2010	Total	Withdrawal capacity, bcfd 2008	2009	2010	Total
Louisiana	28.8	13.2	32.3	74.3	3.1	1.0	1.0	5.1
Texas	13.4	38.7	35.5	87.6	0.9	2.5	1.6	4.9
Alabama	5.4	60.0	—	65.4	0.6	2.2	—	2.8
Mississippi	20.0	24.6	33.1	77.7	1.3	1.3	2.1	4.7
Total	**67.6**	**136.5**	**100.9**	**304.9**	**5.8**	**7.0**	**4.6**	**17.5**

high-deliverability salt-dome storage withdrawal capacity scheduled to enter service 2008-10. Total existing withdrawal capacity of salt dome facilities in Louisiana stands at 3.2 bcfd,[2] the new storage facilities therefore boosting Louisiana's salt dome storage deliverability by almost 160%.

Other potential withdrawal capacity is also under development in the region. The two new Louisiana LNG import terminals—Cheniere Energy's Sabine Pass terminal and Sempra Energy's Cameron terminal—have regasification and sendout capacity of 3.6 bcfd. To the extent LNG inventories are held in storage to move into the market to capture maximum prices, LNG volumes will behave like other natural gas storage.

Including the two new Louisiana LNG import terminals into the total withdrawal capacity for the state pushes the increase in incremental deliverability to 6.8 bcfd, almost double total existing deliverability out of all salt dome and depleted reservoir facilities in the state.

Various industry participants have argued whether this huge investment in storage represents overbuilding. Those rejecting the view that storage is being overbuilt base their arguments on two premises: many of these announced facilities will be delayed or cancelled, and the sporadic nature of LNG deliveries necessitates increased Southeast US-Gulf Coast storage. These points, however, do not preclude the risk of overbuilding.

Cancellation, delays

Rapidly escalating construction costs, long lead times for compressors and steel, unanticipated permitting delays, and deteriorating storage economics leave no doubt a number of the announced projects will be shelved. Most of the facilities scheduled for 2008, however, are nearing completion. Although some will be delayed, it is likely all 5.8 bcfd of withdrawal capacity in this group of 11 projects will enter service within the next 2 years. Handicapping the 22 projects (11.7 bcfd of withdrawal capacity) scheduled for completion in 2009-10 by assuming fully two-thirds of the projects will be canceled, still leaves 3.4 bcfd of additional storage.

These additions combined imply new incremental deliverability of 9.2 bcfd, not including LNG sendout from four new terminals in Texas and Louisiana. Even with a large number of cancellations, therefore, additions to regional deliverability will be large.

Sporadic LNG

LNG remains the wildcard in the storage overbuild equation. Large increases in LNG imports to existing and new Southeast US-Gulf Coast LNG terminals would support a large increase in storage capacity. Recent developments in the global LNG markets plus increases in domestic natural gas production, however, have substantially reduced the volume of LNG imports expected during the next few years.

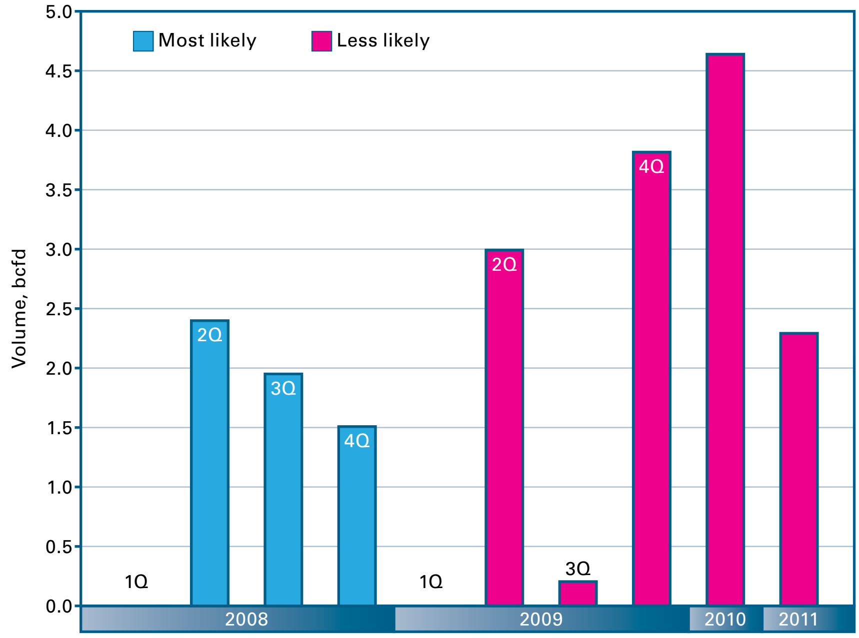
If LNG does not arrive in quantity, the risk of overbuild increases appreciably.

Excess capacity does not define the risk of overbuild; excess deliverability does, in at least two ways. Storage gas will compete with increasing pipeline deliveries in the Southeast US-Gulf Coast region during high withdrawal periods. Constraints on outbound capacity from the region could restrict total deliverability from storage and pipeline sources, particularly for storage facilities competing with LNG terminal sendout on the Gulf Coast and storage facilities in Southeast Texas remaining somewhat constrained by pipeline capacity across the Sabine River into Louisiana.

Increased deliverability from the new salt-dome storage facilities will also increase the market's ability to capture price peaks, effectively capping peak shaving trading opportunities critical to extrinsic storage economics (described later in this article). When prices start to spike, the crowd of new storage players will tend to sell into the increase, limiting it and dampening price volatility. A more viable source for extrinsic storage economics of Gulf Coast salt dome facilities will likely become trough trolling.[3] The opposite of peak shaving, trough trolling uses multicycle storage to inject gas during periods of depressed prices and withdraw it after supply and demand return to a more normal balance.

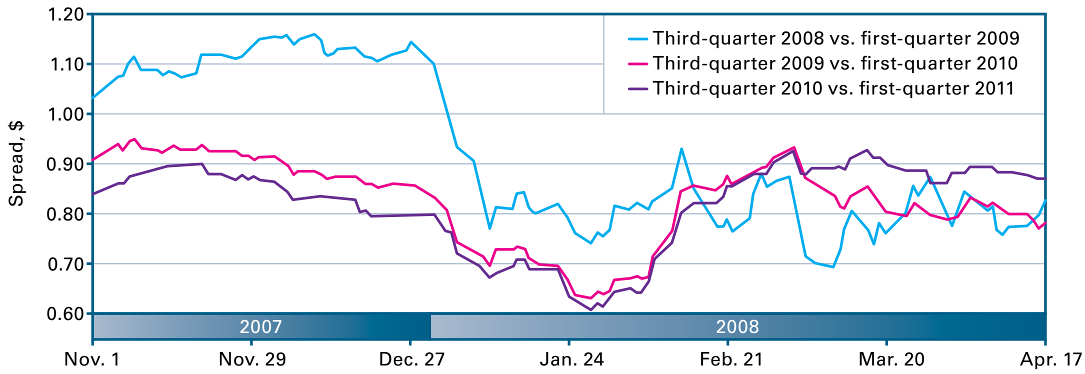
ADDITIONAL STORAGE DELIVERABILITY, 2008-2011

Fig. 1



NYMEX QUARTERLY STRIP, THIRD-QUARTER VS. FIRST-QUARTER

Fig. 2



Intrinsic, extrinsic

Twenty-six of the 31 new storage projects are high-deliverability, multiturn, salt-dome facilities being developed primarily to capture extrinsic storage economics; the trading value associated with short term price fluctuations. Many of these facilities have moved forward as a necessary means of absorbing sporadic LNG imports and were designed to trough troll when LNG oversupply would distress gulf pricing, and peak shave when winter weather, hurricanes, or similar events resulted in price spikes.

The likelihood of any of these scenarios occurring has been diminished by the combined impact of a "deliverability overbuild" and a lower probability of large increases in LNG imports. A more likely scenario over the next few years combines:

- A substantial increase in pipeline capacity into the Southeast US-Gulf Coast region.
- A steady increase in production filling that capacity.
- Continued constraints on deliverability out of the region.
- Modest LNG imports.

Lower volatility, steadily increasing supplies, and periodic constraints on outbound capacity—factors more favorable to storage developed to optimize intrinsic storage economics (the difference between seasonal market prices)—would characterize this scenario. Such storage usually consists of larger, lower-cost, depleted reservoir facilities.

Intrinsic economics as measured by seasonal differences in the forward curve for natural gas have shifted during the past few months.

Fig. 2 shows the difference between the NYMEX quarterly strip for third quarter and first quarter from Nov. 1, 2007, to the present, showing three seasonal spreads:

- Third-quarter 2008 vs. first-quarter 2009 (blue).
- Third-quarter 2009 vs. first-quarter 2010 (pink).
- Third-quarter 2010 vs. third-quarter 2011 (green).

Near the end of 2007, the third-quarter 2008 vs. first-quarter 2009 spread dropped to $0.80/MMbtu from $1.10/MMbtu, a 27% decrease in the implied intrinsic value of storage for the period. At about the same time, the seasonal spread for third-quarter 2009 vs. first-quarter 2010 declined to $0.60/MMbtu from $0.90/MMbtu before recovering to near $0.80/MMbtu the week of Apr. 21, 2008. Third-quarter 2010 vs. first-quarter 2011 spread mirrored the previous years, before separating by about $0.10/MMbtu over the past few months.

The run-up in prompt-month prices in response to cold weather, declining storage inventories, and rapidly escalating crude oil prices fueled a third-quarter 2008 vs. first-quarter 2009 collapse in late December 2007. The collapse brought the seasonal spreads for the three periods discussed in the preceding

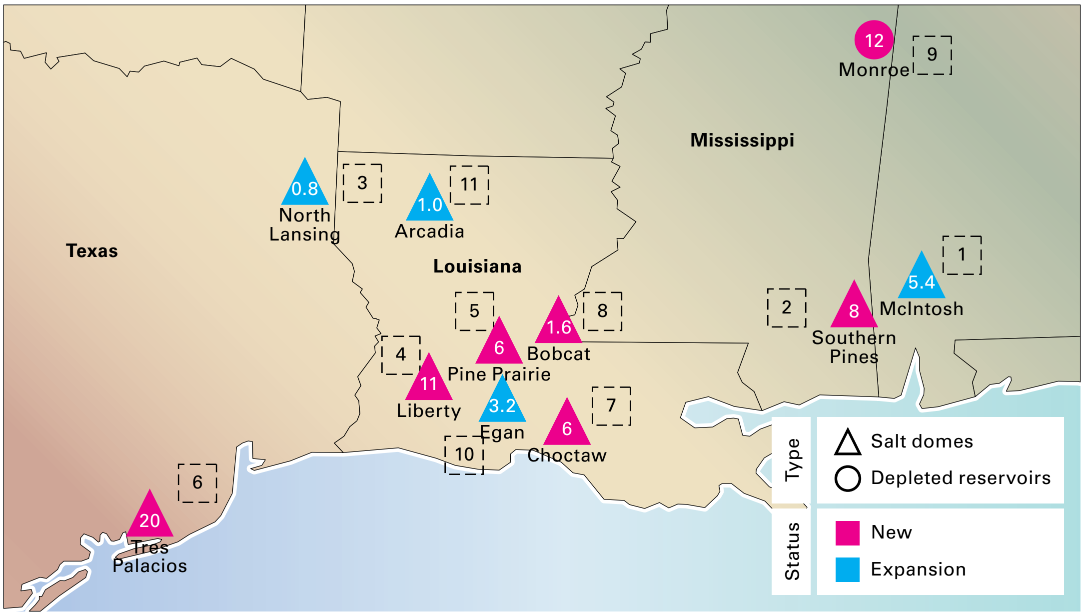
SOUTHEAST US-GULF COAST STORAGE PROJECTS, 2008

Table 2

Project	In-service date	State	County	Status	Type	Storage, MMcf	Withdrawal, MMcfd
McIntosh-Bay Gas	Apr. 1	Alabama	Washington	Expansion	Salt dome	5,400	600
Southern Pines Energy Center	May 1	Mississippi	Greene	New	Depleted reservoir	8,000	800
North Lansing	May 12	Texas	Harrison	Expansion	Depleted reservoir	824	0
Liberty Gas Storage	May 15	Louisiana	Calcasieu	New	Salt dome	11,000	1,000
Pine Prairie Energy Center	July 1	Louisiana	Evangeline	New	Salt dome	6,000	800
Tres Palacios Gas Storage	July 1	Texas	Matagorda, Wharton	New	Salt dome	12,580	850
Choctaw	Sept. 1	Louisiana	Iberia	New	Salt dome	6,000	300
Bobcat	Oct. 1	Louisiana	St. Landry	New	Salt dome	1,600	1,000
Monroe Gas Storage	Oct. 1	Mississippi	Monroe	New	Depleted reservoir	12,000	465
Egan	Nov. 1	Louisiana	Acadia	Expansion	Salt dome	3,150	0
Arcadia	Dec. 15	Louisiana	Bienville	Expansion	Salt dome	1,000	20
		Louisiana				28,750	3,120
		Texas				13,404	850
		Alabama				5,400	600
		Mississippi				20,000	1,265
		Total				**67,554**	**5,835**

Planned storage projects, 2008*

Fig. 3



*Bcf capacities shown inside type-symbol.

paragraph into a relatively narrow range, converging at about $0.85/MMbtu. Spreads have traded within $0.10/MMbtu of this level for about 3 months, suggesting the market has accepted $0.85/MMbtu as a reasonable intrinsic value for storage capacity at this time.

The rest of this article details capacity additions to Southeast US-Gulf Coast storage facilities, grouping the projects by year, and providing the location and size of each. Each annual graphic builds on previous quarters to provide a sense of the magnitude of all projects as a group.

2008

The 11 projects scheduled for completion in 2008 (Fig. 3) will add 5.8 bcfd of new deliverability and 97.6 bcf of incremental working-gas capacity. Four of these projects are expansions and seven are new. Six of the projects are in Louisiana, two in Texas, two in Mississippi, and one in Alabama. Ten of the projects are high-deliverability salt dome storage.

Table 2 shows location, capacity, and type for each of these projects.

1. *McIntosh-Bay Gas.* Bay Gas expanded its McIntosh salt-dome storage cavern in Alabama to 11.4 bcf in spring 2008 and will add another 10 bcf of working-gas capacity by late 2009. Bay Gas provides interconnections to FGT and Gulf South and is adding a connection to Transco.

2. *Southern Pines.* SGR Holdings LLC (60%) and ArcLight Capital Partners own Southern Pines. This facility connects to Florida Gas, Destin, and Transco's Mobile Bay lateral. The Mobile Bay connection will provide access from Southern Pines into Transco Station 85, Gulf South, and Gulfstream. Southern Pines received FERC authorization to begin service and began storage operations in early May.

3. *North Lansing.* North Lansing is a Kinder Morgan depleted-reservoir storage facility in Harrison County, Tex., on the NGPL system. The facility brought 824 MMcfd of working-gas capacity into service in May 2008.

4. *Liberty Gas Storage.* Sempra and Proliance Energy own Liberty, which connects into six pipelines: Tetco, Trunkline, Florida Gas, Transco, Cameron Interstate, and Port Arthur. Expansion plans would add 17.5 bcf. The company has purchased 150 acres of adjacent land for future expansions.

5. *Pine Prairie.* Plains All American Pipeline LP and Vulcan Capital own this facility, which connects to ANR, Texas Gas, FGT, Tennessee-800 leg, Tetco Transco Z3, and Columbia Gulf. The initial cavern measures 6 bcf, with expansions planned to add a second 6-bcf cavern, then expand both of caverns to 8 bcf, and finally add a third 8 bcf cavern. PAA-Vulcan purchased 240 acres of land adjacent to the project for future expansions.

6. *Tres Palacios.* NGS Energy Fund, based in Westport, Conn., is developing this project. Tres Palacios connects to Tennessee, HPL, Enterprise Channel, Kinder Morgan Texas, NGPL, Tetco, Gulf South, Enterprise Valero, FGT, Transco, and CrossTex. After expansions the facility will have 35.6 bcf of working-gas capacity.

7. *Choctaw.* PetroLogistics Natural Gas Storage LLC owns this facility. The FERC-jurisdictional storage cavern will be able to store 9 bcf of gas; 6 bcf working gas and 3 bcf base gas. Choctaw will inject 350 MMcfd and withdraw 300 MMcfd. The project is expected to enter service by September 2008, with interconnects to Sonat, Tetco, FGT, Bridgeline, and CrossTex LIG.

A contract with LNG importer BG Energy Merchants LLC for 100% of initial capacity supports the project. PetroLogistics plans to develop other caverns at the site, providing up to 16 bcf of additional working-gas capacity.

8. *Bobcat.* Haddington Ventures subsidiary Port Barre Investments owns Bobcat Gas Storage. The facility connects

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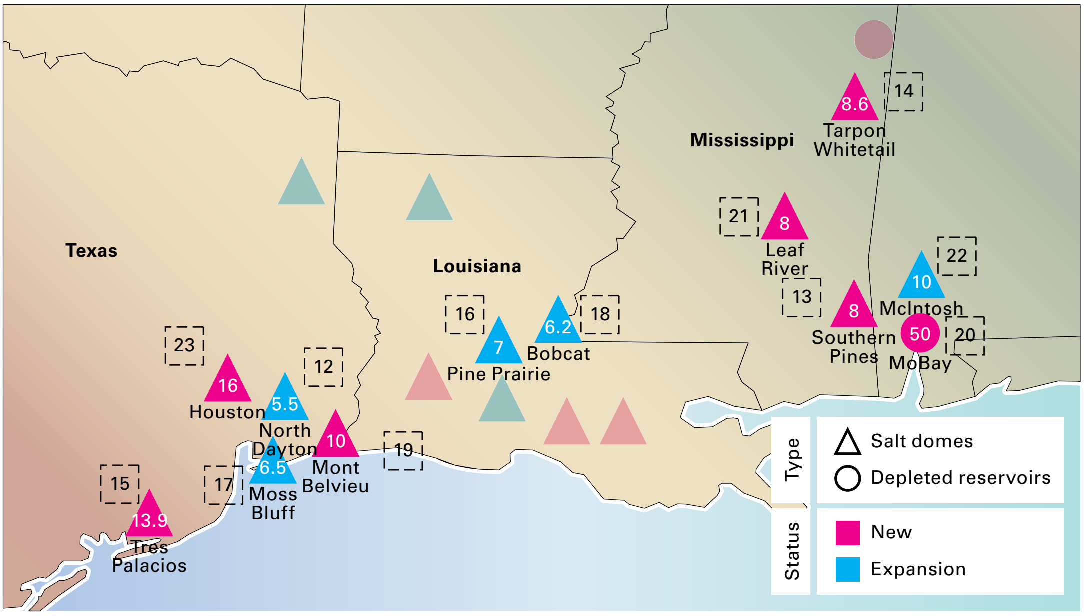
PLANNED STORAGE PROJECTS, 2009*

Fig. 4



*Bcf capacities shown inside type-symbol.

to FGT, Transco, Gulf South, ANR, Tetco, and Cypress.

9. *Monroe Gas Storage.* Foothills Energy Ventures and High Sierra Energy own Monroe, a depleted reservoir project in northeastern Mississippi near Amory. The facility connects to Tetco and Tennessee.

10. *Egan.* This project expands the existing Egan facility owned by Market Hub Partners, a Spectra company. The facility lies in Acadia Parish, La., and connects to Tetco, Tennessee, Columbia Gulf, ANR, Trunkline, Texas Gas, and FGT.

11. *Arcadia.* This project expands the facility owned by Martin Gas of Kilgore, Tex., which has connections with CenterPoint and Gulf South. Four new caverns are expected to enter service in 2008 with a total capacity of 1.0 bcf. Subsequent expansion will increase capacity by 7.0 bcf in 2010 and 13.8 bcf in 2012.

2009

The pace of storage development will increase in 2009, with 12 new projects planned (Fig. 4).

Table 3 identifies five of these projects as the next phase of 2008 developments. New projects in 2009 will add 8.6 bcfd of new deliverability and 150 bcf of new working-gas capacity. Two of these projects are in Louisiana, five in Texas, three in Mississippi and two in Alabama. MoBay supplies the largest single addition to storage capacity; 50 bcf owned by Falcon Gas Storage in Mobile County, Ala.

12. *North Dayton.* North Dayton is a Kinder Morgan expansion project connecting into Transco and Kinder Morgan Texas Pipeline.

13. *Southern Pines.* This project is the next phase of Project 2 (listed under 2008).

14. *Tarpon Whitetail.* Tarpon Gas Storage in Monroe, Miss., is a depleted reservoir with 300 MMcfd of withdrawal capacity connected to TETCO in the M1 rate zone. Planned interconnections include Tennessee's 500 Leg, Sonat, and Mississippi Valley Gas Co. Tarpon is an affiliate of Spark

SOUTHEAST US-GULF COAST STORAGE PROJECTS, 2009

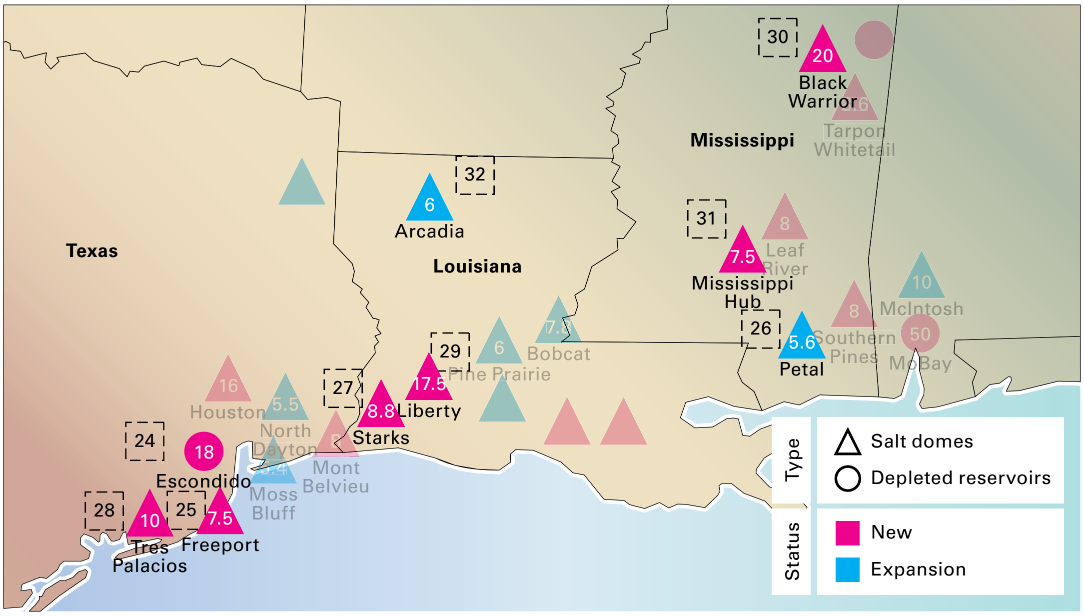
Table 3

Project	In-service date	State	County	Status	Type	Storage, MMcf	Withdrawal, MMcfd
North Dayton	Apr. 1	Texas	Liberty	Expansion	Salt dome	5,500	425
Southern Pines Energy Center[1]	Apr. 1	Mississippi	Greene	Expansion	Salt dome	8,000	400
Tarpon Whitetail	Apr. 1	Mississippi	Monroe	New	Depleted reservoir	8,600	300
Tres Palacios Gas Storage[1]	Apr. 1	Texas	Matagorda, Wharton	Expansion	Salt dome	13,900	825
Pine Prairie Energy Center[1]	June 1	Louisiana	Evangeline	Expansion	Salt dome	7,000	800
Moss Bluff	June 1	Texas	Liberty	Expansion	Salt dome	3,250	250
Bobcat[1]	Aug. 1	Louisiana	St. Landry	Expansion	Salt dome	6,200	200
Mont Belvieu[2]	Cancelled	Texas	Chambers	New	Salt dome	0	0
MoBay	Oct. 1	Alabama	Mobile	New	Depleted reservoir	50,000	1,000
Leaf River	Nov. 1	Mississippi	Smith	New	Salt dome	8,000	625
McIntosh-Bay Gas[1]	Nov. 1	Alabama	Washington	Expansion	Salt dome	10,000	1,200
Houston Storage Hub	Nov. 1	Texas	Liberty	New	Salt dome	16,000	1,000
		Louisiana				13,200	1,000
		Texas				38,650	2,500
		Alabama				60,000	2,200
		Mississippi				24,600	1,325
		Total				**136,450**	**7,025**

[1]Next phase of existing project. [2]Mont Belvieu had a planned 10 bcf capacity.

PLANNED STORAGE PROJECTS, 2010*

Fig. 5



*Bcf capacities shown inside type-symbol.

Energy Holdings.

15. *Tres Palacios.* This project is the next phase of Project 6 (see 2008).

16. *Pine Prairie.* This project is the next phase of Project 5.

17. *Moss Bluff.* Spectra's Market Hub Partners plans to add 6.5 bcf of working-gas capacity to this salt dome storage field by summer 2011, developing a fourth cavern at the Liberty County, Tex., site. Plans call for a portion of the additional capacity to be available in June 2009. The facility currently has 15 bcf of working-gas capacity.

18. *Bobcat.* This project is the next phase of Project 8.

19. *Mont Belvieu.* Mont Belvieu gas storage, a venture of Enterprise Products and Duncan Energy, held an open season earlier in 2008 for 10 bcf of storage east of Houston.

The project would have involved conversion of existing NGL caverns and the construction of natural gas pipeline interconnects with Enterprise Texas, Enterprise Texas Intrastate (Channel), Kinder Morgan Texas Pipeline, and Tetco. Enterprise, however, has since said it does not plan to move forward on the project because of inadequate market interest.

20. *MoBay.* MoBay is a large depleted reservoir facility in Mobile County, Ala., adjacent to Gulfstream Station 410. Falcon Gas Storage is developing the 50-bcf facility, which will connect to Transco's Mobile Bay Lateral, Gulfstream, FGT Zone 3, Gulf South, Southeast Supply Header, and Destin.

21. *Leaf River.* NGS Energy is developing its Leaf River salt dome gas-storage project in Smith County, Miss.; providing 8 bcf working-gas capacity in its initial phase, with plans to grow to as much as 32 bcf. NGS expects the project to provide 2.5 bcfd of withdrawal capacity and 1 bcfd of injection capacity, with a proposed in-service date of July 2009.

22. *McIntosh-Bay Gas.* This project is the next phase of Project 1.

23. *Houston Storage Hub (formerly Houston Energy Center).* Enstor (Scottish Power) plans to bring the initial 7.5-bcf phase of this project online in second-quarter

SOUTHEAST US-GULF COAST STORAGE PROJECTS, 2010

Table 4

Project	In-service date	State	County	Status	Type	Storage, MMcf	With-drawal, MMcfd
Escondido	Mar. 1	Texas	Karnes, Live Oak	New	Depleted reservoir	18,000	335
Freeport, Stratton Ridge	Apr. 1	Texas	Brazoria	New	Salt dome	7,500	400
Petal Salt Dome	Apr. 1	Mississippi	Forrest	Expansion	Salt dome	5,600	700
Starks Gas Storage	Apr. 1	Louisiana	Calcasieu	New	Salt dome	8,800	400
Tres Palacios Gas Storage*	Apr. 1	Texas	Matagorda, Wharton	Expansion	Salt dome	10,000	825
Liberty Gas Storage*	May 1	Louisiana	Calcasieu	Expansion	Salt dome	17,500	0
Black Warrior Storage	June 1	Mississippi	Monroe	New	Depleted reservoir	20,000	375
Mississippi Hub	Nov. 1	Mississippi	Simpson	New	Salt dome	7,500	1,000
Arcadia*	Nov. 1	Louisiana	Bienville	Expansion	Salt dome	6,000	600
		Louisiana				32,300	1,000
		Texas				35,500	1,560
		Alabama				0	0
		Mississippi				33,100	2,075
		Total				**100,900**	**4,635**

*Next phase of existing project.

2009. A 7.7-bcf expansion is planned for 2 years later. The Houston Hub has interconnects with Enstor's Katy facility, HPL, Transco, Trunkline, NGPL, Tennessee, Tejas Gas, and Kinder Morgan Texas (MidCon).

2010

Current plans call for nine additional storage projects by 2010 (Fig. 5). Table 4 shows three of these projects as the next phase of 2008 developments. Three projects are in Texas, three in Mississippi, and three in Louisiana.

24. *Escondido.* Escondido Gas Storage is developing an 18 bcf storage field 55 miles southeast of San Antonio in Karnes and Live Oak counties, using the depleted Atkinson gas field. Design plans include an injection rate of 275 MMcfd and a withdrawal rate of 335 MMcfd, allowing 3-4 cycles/year. Escondido expects the project to be in service by March 2010.

25. *Freeport (Stratton Ridge).* Freeport LNG plans to add salt-dome gas storage at Stratton Ridge in Brazoria County, Tex., but has made no firm announcements about the project.

26. *Petal.* Petal Gas Storage, a subsidiary of Enterprise Products Partners, plans to expand its salt-dome storage near Petal, Miss., by April 2010, adding 5.6 bcf of working-gas capacity.

27. *Starks Gas Storage.* Niska's Starks Gas storage project includes conversion of two existing salt caverns to gas-storage operations. The project would be about 25 miles west of Lake Charles, La., and would initially provide 8 bcf of working-gas capacity from one cavern, with a maximum withdrawal rate of 400 MMcfd and a maximum injection rate of 375 MMcfd. Niska would add a second cavern at a later date, bringing working-gas capacity to 18 bcf and doubling injection and withdrawal rates.

28. *Palacios.* This project is the third phase of Projects 6 and 15.

29. *Liberty.* This project is the next phase of Project 4.

30. *Black Warrior Storage.* Southeast Gas Storage LLC (SGS), an affiliate of El Paso-Tennessee is developing the 20-bcf Black Warrior Storage Project, in Monroe County, Miss. The proposed depleted-field gas storage would interconnect with Tennessee's 500 Line downstream of its Columbus compressor station in Zone 1 via a new 24-in. OD pipeline. The facility would provide as much as 333 MMcfd of injection capacity and 375 MMcfd of withdrawal capacity, with a proposed in-service date of June 2010.

31. *Mississippi Hub.* EnergySouth is building its Mississippi Hub facility at the Bond Salt Dome structure near Jackson County, Miss. The company plans to complete it in two phases; the first of two caverns becoming operational in late 2009, the second in mid-2011. EnergySouth expects the project to have 15 bcf of working-gas capacity, 1.5 bcfd of withdrawal capability, and 750 MMcfd of injection capacity by November 2009. It plans interconnections with Sonat, Transco, and SESH.

32. *Arcadia.* Martin Midstream began storage services at the Arcadia storage field in 2007 and plans to boost working-gas capacity by 1 bcf by adding a fourth cavern in December 2008. Deliverability would total 200 MMcfd and injection capacity is to reach 125 MMcfd.

Phase II and Phase III expansions each consist of constructing a new cavern with 7 bcf of working-gas capacity, to be completed in August 2010 and August 2012, respectively. Phase II would provide 600 MMcfd of incremental withdrawal capacity and 170 MMcfd of additional injection capacity. ✦

References

1. Estimate of Maximum Underground Working Gas Storage Capacity in the United States: 2007 Update, Energy Information Administration, 2007.

2. Bentek Market Alert: "I" of the Storm, Part One, Bentek Energy LLC, Mar. 11, 2008.

3. Murrell, R., Energy South presentation to LDC Forum-Southeast, Atlanta, Apr. 14-16, 2008.

Equipment/Software/Literature

New hydrogen sulfide analyzer

The new Model 903 hydrogen sulfide tape analyzer is designed to measure as many as four streams of H_2S and total sulfur in gaseous streams.

It has a 20 sec response time.

New capabilities include:

- 0-2,000 ppm range without dilution.
- Linearity and repeatability of ±1% of full scale.
- 5-15 week tape life.
- Overrange and multirange measurement.

Operators can measure the extent to which H_2S exceeds preset alarm levels as well as use the quick response H_2S analyzer in new, higher ppm applications.

In addition, the analyzer can read samples from different ranges. This multi-range capability replaces the need for separate analysers calibrated each for separate streams. Other features include built-in modbus communications/RTU capabilities, a greater number of outputs and inputs, sensor autocalibration on each analysis, and dual redundant power supply.

Source: **Galvanic Applied Sciences Inc.,** 7000 Fisher Rd. SE, Calgary, Alta. T2H 0W3.

New valve-test bench

Here's a new pressure test bench for valves requiring production or engineering tests.

The maker says its comprehensive test bench provides independent gas and liquid test circuits with controls tailored to duplicate operating conditions for the valve product, including actuator. Benches offer what the firm says is quick, safe, expedient testing for all valves and valve actuators that require gas and-or liquid pressure testing to prove performance and pressure integrity.

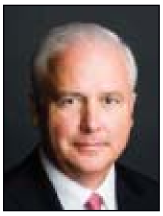
The bench operates in a pressure range of 200-10,000 psi using glycol based hydraulic fluid, air, and hydraulic oil at a flow rate of 1 gpm test flow, 5 gpm filtration flow. The bench measures 7 ft wide by 6 ft high by about 2 ft deep, utilizes one Maximator air amplifier and three Maximator liquid pumps, and has five integral test bench features:

- Amplified air test circuit.
- Hydrostatic test and valve actuator operating system.
- Hydraulic force loading of valve actuator.
- High pressure cleanliness flushing with powered filtration system.
- Chart recorder data collection.

Source: **Maxpro Technologies Inc.,** 7728 Klier Drive South, Fairview, PA 16415.

Key Energy Services Inc.,

Houston, has named Newton W. "Trey" Wilson III executive vice-president and chief operating officer (COO). Wilson has served as general counsel since joining the company in 2005. He has also served as senior vice-president and secretary and is a member of Key's executive management committee. Naming him COO is part of a new executive structure designed to bolster top management's ability to execute more effectively and yield more efficient operating results. Wilson holds a BBA from Southern Methodist University and a JD from the University of Texas.


Wilson

Key is the world's largest rig-based well service company. It provides oil field services including well servicing, pressure pumping, fishing and rental tools, electric wireline, and other oil field services. The company has operations in all major US onshore regions and in Argentina.

Knight Oil Tools,

Lafayette, La., has promoted three employees to new vice-president positions. Knight named Mickey Broussard vice-president of operations for Knight Oil Tools. He will be responsible for capital expenditures, overseeing all physical stores and facilities, equipment inventory and equipment maintenance. Broussard has held various positions with Knight since joining the company in 1980. He studied engineering at the University of Louisiana at Lafayette and civil engineering at TH Harris Technical College. Clark Carnes was promoted to vice-president of Knight Fishing Services, where he will be responsible for the company's continued growth as an industry leader in fishing tools and services. Carnes has served with Knight for 20 years, most recently directing the sales force for Knight. He has a BBA from Auburn University. Knight promoted Doug Keller to vice-president of sales. Previously, he was vice-president of marketing and business development at Knight after having worked on Knight's sales and sales management team for 22 years. He has a bachelor's degree from Louisiana Tech University.


Broussard


Carnes


Keller

Knight Oil Tools is the largest privately held rental tool business in the oil and gas industry.

Bourbon,

Paris, will sell its interest in Rigdon Marine Corp. under a recently announced merger proposal between offshore service fleet operators Rigdon, New Orleans, and Gulfmark Offshore, Houston. Bourbon's sale is expected to occur in third quarter 2008 and generate a capital gain of about €60 million, as well as repayment by Rigdon of loans totaling €110 million. Bourbon has contributed to Rigdon's finances since January 2006.

Bourbon offers a broad range of offshore oil and gas services with a fleet of 236 owned vessels and 204 units on order.

The combined company resulting from Gulfmark's acquisition of Rigdon will initially operate 90 vessels, with another 16 vessels under construction for delivery through 2010. The deal gives Gulfmark its first significant presence in the US Gulf of Mexico, as well as the North Sea, Brazil, and Southeast Asia, to complement smaller but growing operating areas in Trinidad and Tobago, Mexico, West Africa, and India.

GE Fanuc Intelligent Platforms,

Charlottesville, Va., has completed the acquisition of assets of the MTL Open System Technologies product lines—including the MTL8000 general purpose I/O, intrinsically safe I/O, SafetyNet system, and process control technologies—from MTL Instruments Group. Addition of these product lines will help GE Fanuc better address process and safety needs of the petroleum industry, among other process industries.

A unit of GE Enterprise Solutions, GE Fanuc Intelligent Platforms is a joint venture of General Electric and Fanuc Ltd. of Japan. It provides hardware, software, services, expertise, and experience in automation and embedded computing, with products employed in virtually every industry.

Institut Français du Pétrole

(IFP), Rueil-Malmaison, France, has appointed Rémi Eschard director of IFP's Geology-Geochemistry-Geophysics Division. He has taken over from Bernard Coletta, who is to be assigned new responsibilities. Eschard joined IFP in 1989 in the Geology-Geochemistry Division. In 1997, he was appointed project manager in reservoir geology before taking over the helm of the Sedimentology-Stratigraphy Department of the Geology-Geochemistry-Geophysics Division in 2001. Since 2005, he led the reservoir characterization area in the Exploration-Production Technology Business Unit. Eschard graduated as an engineer at the IFP School and holds a doctorate in sedimentary geology from Louis Pasteur University.

IFP is a world-class public-sector research and training center focused on developing the technologies and materials of the future in the fields of energy, transport, and the environment.

Transocean Inc.,

Houston, shareholders elected Jon A. Marshall, Martin B. McNamara, Robert E. Rose, and Ian C. Strachan as Class III directors to serve 3-year terms expiring in 2011. Marshall is the former president and COO of Transocean; McNamara is a partner of the law firm of Gibson, Dunn & Crutcher; Rose is the non-executive chairman of Transocean's board and previously served as the non-executive chairman of GlobalSantaFe Corp.; and Strachan is on the boards of several public companies.

Transocean Inc. is the world's largest offshore drilling contractor and a leading provider of drilling management services worldwide.

Imports of crude and products

	Districts 1-4 6-27 2008	Districts 1-4 6-20 2008	District 5 6-27 2008	District 5 6-20 2008	Total US 6-27 2008	Total US 6-20 2008	Total US *6-29 2007
	1,000 b/d						
Total motor gasoline	1,356	1,162	—	—	1,356	1,162	1,392
Mo. gas. blending comp.	857	756	—	—	857	756	893
Distillate	149	107	—	—	149	107	313
Residual	357	335	12	—	369	335	251
Jet fuel-kerosine	66	101	—	13	66	114	293
Propane-propylene	105	79	2	2	107	81	130
Other	544	690	131	51	675	741	489
Total products	**3,434**	**3,230**	**145**	**66**	**3,579**	**3,296**	**3,761**
Total crude	**8,605**	**9,058**	**1,563**	**1,193**	**10,168**	**10,251**	**10,778**
Total imports	**12,039**	**12,288**	**1,708**	**1,259**	**13,747**	**13,547**	**14,539**

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

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center.

OGJ crack spread

	*7-4-08	*7-6-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	151.56	91.17	60.39	66.2
Brent crude	142.88	74.02	68.86	93.0
Crack spread	8.68	17.15	–8.48	–49.4
FUTURES MARKET PRICES				
One month				
Product value	156.35	92.28	64.07	69.4
Light sweet crude	142.46	71.78	70.68	98.5
Crack spread	13.90	20.50	–6.60	–32.2
Six month				
Product value	157.09	86.42	70.67	81.8
Light sweet crude	143.99	72.70	71.29	98.1
Crack spread	13.11	13.73	–0.62	–4.5

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

Purvin & Gertz LNG netbacks—July 4, 2008

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	9.27	6.58	8.15	6.43	7.39	8.04
Everett	10.43	7.51	9.90	7.52	8.34	10.85
Isle of Grain	12.59	9.56	11.65	9.41	10.42	11.68
Lake Charles	8.40	6.01	8.07	6.11	6.38	9.30
Sodegaura	7.39	9.73	7.62	9.92	8.96	6.39
Zeebrugge	9.71	7.10	9.04	6.97	7.91	9.03

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	14,218	58,996	31,714	9,842	41,264	15,154	3,967
PADD 2	64,448	50,585	17,141	7,552	30,621	1,380	17,171
PADD 3	148,764	67,296	32,079	12,837	33,145	17,617	19,065
PADD 4	13,920	5,808	1,792	586	3,186	310	[1]1,233
PADD 5	58,426	28,172	21,424	8,816	12,469	5,539	—
June 27, 2008	**299,776**	**210,857**	**104,150**	**39,633**	**120,685**	**40,000**	**41,436**
June 20, 2008	**301,758**	**208,757**	**102,465**	**40,500**	**119,421**	**39,253**	**39,694**
June 29, 2007[2]	**354,042**	**204,433**	**90,360**	**40,619**	**121,610**	**34,845**	**43,911**

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

Refinery report—June 27, 2008

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,455	1,453	2,035	106	518	135	60
PADD 2	3,460	3,424	2,430	228	1,049	52	227
PADD 3	7,396	7,241	2,940	760	2,236	313	674
PADD 4	550	548	290	23	173	11	[1]156
PADD 5	2,838	2,747	1,344	447	595	168	—
June 27, 2008	**15,699**	**15,413**	**9,039**	**1,564**	**4,571**	**679**	**1,117**
June 20, 2008	**15,588**	**15,258**	**9,057**	**1,614**	**4,588**	**573**	**1,086**
June 29, 2007[2]	**15,704**	**15,544**	**9,402**	**1,463**	**4,010**	**613**	**1,157**
	17,594 operable capacity		**89.2% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 7-2-08	Pump price* 7-2-08	Pump price 7-4-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	368.8	413.2	300.1
Baltimore	361.7	403.6	297.0
Boston	364.7	406.6	290.1
Buffalo	362.0	421.6	300.5
Miami	372.0	423.6	301.8
Newark	363.1	396.0	285.2
New York	354.3	413.9	301.1
Norfolk	357.6	395.6	289.7
Philadelphia	362.4	413.1	303.2
Pittsburgh	352.6	403.3	292.0
Wash., DC	374.8	413.2	299.5
PAD I avg	363.1	409.4	296.4
Chicago	386.5	444.4	316.3
Cleveland	354.0	400.4	270.8
Des Moines	359.3	399.4	294.0
Detroit	356.0	410.4	313.8
Indianapolis	350.2	400.3	302.9
Kansas City	360.4	396.4	289.8
Louisville	366.6	403.5	300.1
Memphis	350.0	389.8	293.5
Milwaukee	361.2	412.5	300.6
Minn.-St. Paul	361.0	401.4	281.2
Oklahoma City	351.7	387.1	282.9
Omaha	355.5	397.8	291.0
St. Louis	357.5	393.5	301.0
Tulsa	350.9	386.3	283.8
Wichita	333.1	376.5	294.7
PAD II avg	356.9	400.0	294.4
Albuquerque	352.9	389.3	298.2
Birmingham	358.7	397.3	286.6
Dallas-Fort Worth	363.9	402.3	286.3
Houston	355.9	394.3	283.6
Little Rock	355.9	396.1	287.0
New Orleans	360.9	399.3	292.5
San Antonio	353.9	392.3	283.2
PAD III avg	357.4	395.8	288.2
Cheyenne	362.1	394.6	291.5
Denver	369.0	409.4	311.7
Salt Lake City	359.9	402.8	313.6
PAD IV avg.	363.7	402.2	305.6
Los Angeles	394.4	458.3	313.0
Phoenix	387.9	425.3	302.6
Portland	390.0	433.4	310.9
San Diego	403.4	467.3	324.8
San Francisco	398.5	462.4	322.0
Seattle	388.0	442.4	302.0
PAD V avg.	393.7	448.2	312.6
Week's avg.	**364.4**	**408.8**	**297.3**
June avg.	**360.2**	**404.2**	**309.4**
May avg.	**329.3**	**372.9**	**307.6**
2008 to date	**298.2**	**341.9**	—
2007 to date	**224.6**	**268.2**	—

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

REFINED PRODUCT PRICES

	6-27-08 ¢/gal		6-27-08 ¢/gal
Spot market product prices			
		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	391.40
New York Harbor	335.02	Gulf Coast	388.60
Gulf Coast	338.37	Gas oil	
Los Angeles	351.12	ARA	403.07
Amsterdam-Rotterdam-		Singapore	411.19
Antwerp (ARA)	330.02		
Singapore	347.71	Residual fuel oil	
Motor gasoline		New York Harbor	260.19
(Reformulated-regular)		Gulf Coast	262.43
New York Harbor	350.52	Los Angeles	271.38
Gulf Coast	357.12	ARA	272.22
Los Angeles	360.12	Singapore	256.54

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

BAKER HUGHES RIG COUNT

	7-4-08	7-6-07
Alabama	5	5
Alaska	4	9
Arkansas	59	48
California	43	35
Land	43	34
Offshore	0	1
Colorado	111	108
Florida	1	1
Illinois	1	0
Indiana	2	3
Kansas	11	8
Kentucky	7	8
Louisiana	176	181
N. Land	74	56
S. Inland waters	20	22
S. Land	29	33
Offshore	53	70
Maryland	1	1
Michigan	1	1
Mississippi	13	14
Montana	12	19
Nebraska	0	0
New Mexico	81	87
New York	5	5
North Dakota	70	35
Ohio	13	13
Oklahoma	209	191
Pennsylvania	25	11
South Dakota	2	3
Texas	923	825
Offshore	8	7
Inland waters	2	0
Dist. 1	22	23
Dist. 2	33	26
Dist. 3	59	67
Dist. 4	95	90
Dist. 5	187	174
Dist. 6	121	120
Dist. 7B	33	36
Dist. 7C	67	55
Dist. 8	143	106
Dist. 8A	27	27
Dist. 9	42	35
Dist. 10	84	59
Utah	44	37
West Virginia	19	25
Wyoming	76	71
Others—NV-2; OR-1; TN-1; VA-2; WA-1	7	8
Total US	**1,921**	**1,752**
Total Canada	**388**	**286**
Grand total	**2,309**	**2,038**
Oil rigs	373	274
Gas rigs	1,539	1,473
Total offshore	63	79
Total cum. avg. YTD	**1,821**	**1,746**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	7-4-08 Rig count	7-4-08 Percent footage*	7-4-07 Rig count	7-4-07 Percent footage*
0-2,500	84	3.5	59	6.7
2,501-5,000	146	45.2	109	52.2
5,001-7,500	255	15.6	249	23.2
7,501-10,000	469	3.1	413	3.3
10,001-12,500	486	2.8	456	2.1
12,501-15,000	329	—	265	—
15,001-17,500	139	—	108	0.9
17,501-20,000	84	—	68	—
20,001-over	38	—	39	—
Total	**2,030**	**6.7**	**1,766**	**8.1**
INLAND	32		44	
LAND	1,937		1,655	
OFFSHORE	61		67	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]7-4-08	[2]7-6-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	19
Alaska	720	715
California	658	667
Colorado	43	39
Florida	5	5
Illinois	25	26
Kansas	95	101
Louisiana	1,329	1,307
Michigan	14	17
Mississippi	53	56
Montana	92	95
New Mexico	163	163
North Dakota	116	122
Oklahoma	171	170
Texas	1,350	1,345
Utah	45	50
Wyoming	148	149
All others	61	94
Total	**5,103**	**5,140**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	7-4-08 $/bbl*
Alaska-North Slope 32°	120.20
South Louisiana Sweet	148.75
California-Kern River 13°	131.05
Lost Hills 30°	139.10
Southwest Wyoming Sweet	135.29
East Texas Sweet	141.25
West Texas Sour 34°	134.25
West Texas Intermediate	141.75
Oklahoma Sweet	141.75
Texas Upper Gulf Coast	138.25
Michigan Sour	134.75
Kansas Common	140.75
North Dakota Sweet	135.50

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

	6-27-08 $/bbl[1]
United Kingdom-Brent 38°	135.98
Russia-Urals 32°	131.29
Saudi Light 34°	130.90
Dubai Fateh 32°	129.39
Algeria Saharan 44°	136.67
Nigeria-Bonny Light 37°	140.30
Indonesia-Minas 34°	138.15
Venezuela-Tia Juana Light 31°	131.90
Mexico-Isthmus 33°	131.79
OPEC basket	134.16
Total OPEC[2]	131.47
Total non-OPEC[2]	131.33
Total world[2]	131.41
US imports[3]	128.02

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume. Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	6-27-08	6-20-08	6-27-07	Change, %
	bcf			
Producing region	703	685	863	–18.5
Consuming region east	1,116	1,059	1,263	–11.6
Consuming region west	299	289	373	–19.8
Total US	**2,118**	**2,033**	**2,499**	**–15.2**

	Apr. 08	Apr. 07	Change, %
Total US[2]	**1,436**	**1,720**	**–16.5**

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Apr. 2008	Mar. 2008	3 month average production 2008	3 month average production 2007	Change vs. previous year Volume	Change vs. previous year %	Apr. 2008	Mar. 2008	Cum. 2008
	Crude, 1,000 b/d						Gas, bcf		
Argentina	630	640	631	630	1	0.2	140.0	150.0	552.18
Bolivia	39	39	41	45	–4	–8.8	41.9	43.2	166.10
Brazil	1,797	1,750	1,774	1,751	23	1.3	37.0	39.0	145.00
Canada	2,545	2,583	2,555	2,613	–58	–2.2	459.8	499.8	1,959.90
Colombia	567	562	562	520	41	8.0	22.0	22.0	86.00
Ecuador	500	500	500	500	—	—	1.0	1.0	4.00
Mexico	2,767	2,847	2,875	3,164	–289	–9.1	201.4	207.1	800.80
Peru	113	95	107	112	–4	–3.8	8.0	8.5	31.00
Trinidad	107	119	114	125	–11	–8.7	114.3	111.8	463.72
United States	5,098	5,139	5,111	5,185	–74	–1.4	1,755.0	1,828.0	7,059.00
Venezuela[1]	2,320	2,350	2,380	2,420	–40	–1.7	70.0	75.0	297.00
Other Latin America	80	80	80	80	—	0.1	5.3	5.5	21.66
Western Hemisphere	**16,563**	**16,705**	**16,730**	**17,143**	**–414**	**–2.4**	**2,855.8**	**2,991.0**	**11,586.36**
Austria	16	16	16	17	–1	–6.2	5.0	5.4	20.70
Denmark	291	285	290	315	–25	–7.9	28.4	29.7	119.07
France	20	20	21	19	2	9.5	3.0	3.1	12.24
Germany	61	61	62	70	–7	–10.3	50.0	50.6	199.31
Italy	107	101	108	109	–1	–1.1	25.0	26.0	103.00
Netherlands	40	39	40	42	–3	–5.9	320.0	350.0	1,390.00
Norway	2,111	2,209	2,181	2,426	–245	–10.1	301.2	336.3	1,288.00
Turkey	41	38	39	40	–1	–2.4	—	—	—
United Kingdom	1,518	1,470	1,493	1,595	–103	–6.4	224.8	250.5	962.95
Other Western Europe	4	4	4	4	—	–4.3	2.0	2.2	11.06
Western Europe	**4,209**	**4,243**	**4,254**	**4,638**	**–384**	**–8.3**	**959.5**	**1,053.8**	**4,106.33**
Azerbaijan	920	945	939	813	126	15.5	30.0	35.0	126.00
Croatia	15	15	15	16	–1	–6.1	5.6	6.0	22.30
Hungary	15	14	14	17	–2	–13.5	7.5	7.1	28.96
Kazakhstan	1,400	1,360	1,380	1,075	305	28.4	50.0	75.0	263.00
Romania	95	95	95	98	–3	–2.8	17.0	18.0	70.00
Russia	9,680	9,730	9,743	9,878	–135	–1.4	2,000.0	2,100.0	8,200.00
Other FSU	400	400	400	413	–13	–3.0	400.0	540.0	1,990.00
Other Eastern Europe	50	50	50	49	1	1.2	2.9	19.7	59.43
Eastern Europe and FSU	**12,576**	**12,609**	**12,636**	**12,357**	**278**	**2.3**	**2,513.0**	**2,800.9**	**10,759.68**
Algeria[1]	1,380	1,390	1,388	1,333	55	4.1	270.0	280.0	1,095.00
Angola[1]	1,932	1,861	1,901	1,634	268	16.4	5.0	4.9	19.60
Cameroon	85	85	87	84	3	3.4	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	620	620	625	653	–28	–4.2	135.0	140.0	545.00
Equatorial Guinea	320	320	320	320	—	0.0	0.1	0.1	0.24
Gabon	220	210	225	230	–5	–2.2	0.3	0.3	1.22
Libya[1]	1,750	1,760	1,760	1,693	68	4.0	32.0	35.0	134.00
Nigeria[1]	1,840	2,010	2,003	2,233	–230	–10.3	70.0	78.0	303.00
Sudan	480	480	480	458	23	4.9	—	—	—
Tunisia	79	80	81	95	–14	–15.0	3.7	6.5	22.92
Other Africa	232	232	232	232	—	—	9.8	10.2	39.50
Africa	**9,198**	**9,308**	**9,361**	**9,222**	**139**	**1.5**	**525.8**	**554.9**	**2,160.48**
Bahrain	170	169	169	171	–1	–0.7	24.0	25.0	94.88
Iran[1]	3,900	4,020	3,993	3,920	73	1.8	300.0	310.0	1,200.00
Iraq[1]	2,400	2,410	2,388	1,945	443	22.8	19.0	19.4	75.20
Kuwait[1,2]	2,600	2,600	2,588	2,425	163	6.7	38.0	40.0	153.00
Oman	710	760	723	720	3	0.3	55.0	60.0	228.00
Qatar[1]	830	840	843	798	45	5.6	165.0	170.0	665.00
Saudi Arabia[1,2]	8,920	8,950	8,975	8,473	503	5.9	210.0	220.0	855.00
Syria	380	390	388	393	–5	–1.3	17.0	18.0	70.00
United Arab Emirates[1]	2,650	2,540	2,630	2,565	65	2.5	130.0	130.0	530.00
Yemen	310	310	315	353	–38	–10.6	—	—	—
Other Middle East	—	—	—	—	—	–48.2	9.4	11.0	42.98
Middle East	**22,870**	**22,989**	**23,009**	**21,761**	**1,249**	**5.7**	**967.4**	**1,003.5**	**3,914.06**
Australia	453	416	420	449	–29	–6.4	111.4	111.0	428.80
Brunei	147	171	170	187	–17	–9.0	31.6	37.2	140.61
China	3,761	3,779	3,769	3,756	13	0.3	217.9	258.0	937.00
India	676	702	678	692	–14	–2.1	86.8	85.3	337.59
Indonesia[1]	860	871	860	848	12	1.4	190.0	200.0	780.00
Japan	16	18	19	19	—	1.4	10.6	11.7	47.83
Malaysia	790	770	778	745	33	4.4	145.0	150.0	585.00
New Zealand	62	57	61	18	44	248.6	12.0	12.0	46.90
Pakistan	66	66	67	66	2	2.6	120.4	127.4	495.75
Papua New Guinea	10	10	10	13	–3	–20.0	0.9	1.0	3.80
Thailand	226	214	218	210	8	3.6	44.0	47.0	181.00
Viet Nam	300	280	303	325	–23	–6.9	15.0	15.0	59.00
Other Asia-Pacific	30	35	31	35	–4	–12.3	88.3	96.5	368.97
Asia-Pacific	**7,398**	**7,389**	**7,382**	**7,361**	**21**	**0.3**	**1,073.9**	**1,152.0**	**4,412.25**
TOTAL WORLD	**72,813**	**73,243**	**73,371**	**72,482**	**889**	**1.2**	**8,895.3**	**9,556.1**	**36,939.15**
OPEC	31,882	32,102	32,206	30,284	1,922	6.3	1,500.0	1,563.3	6,110.80
North Sea	3,938	3,982	3,982	4,355	–373	–8.6	650.3	721.2	2,785.76

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

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Energy politics follows laws like those of physics

Politics and physics have disparate meanings for the word "energy" yet adhere in their treatment of the subject to natural laws with interesting similarities.

Defining "energy" with technical precision is difficult, of course. Defining the word politically is impossible.

Technically, energy relates to the ability to perform work and transfer heat. Engineers and physicists discuss it in terms such as ergs, joules, and degrees.

The Editor's Perspective

by Bob Tippee, Editor

In politics, "energy" means whatever anyone needs it to mean. This flexibility frees political discussion of worry about the physical world's thermodynamic constraints. The basic political terms applicable to energy include dollars, euros, and yuan.

Despite these contrasts, parallel laws do seem to be at work.

The physics of energy, for example, concerns itself with shifts between varying degrees of energy usefulness. It employs tools such as engines, turbines, and batteries.

The politics of energy concentrates on shifts, too: of money. Its tools are taxes, mandates, and subsidies.

Like energy, politics has useful and useless states. Also like energy, politics seems drawn by some natural law in the direction of uselessness.

Observation makes clear that as rhetorical heat rises in a political system addressing energy, disorder overwhelms discussion, degrading the consequent ideas.

Evidence of this political version of entropy abounds. It includes proposals to outlaw "price-gouging," to rein in the supposed excesses of "speculators," and to tax hydrocarbons in order to fund energy of lesser utility.

Energy politics has its peculiarities.

In physics and engineering, attention to energy is constant.

In politics, attention to energy—rhetorical heat—varies as a function of the price of vehicle fuel. And since the quality of political ideas for energy varies as an inverse function of rhetorical heat, it follows that the risk of policy error rises with prices of gasoline and diesel fuel.

Price levels exist, however, below which political attention and therefore rhetorical heat seem to vanish.

Such a political state, of zero attention to energy, might seem like the good old days.

But political inattention of the past helps explain energy prices of the present, suggesting that politics, like energy, changes only in form, never in quantity.

(Online July 4, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Chinese demand pushes oil prices higher

Increased energy consumption in China and other developing countries is outstripping demand destruction in the US and Europe and is pushing oil prices still higher, analysts said.

Total energy consumption around the globe was up 2.4% in 2007, slightly lower than the 2.7% increase in 2006 but still above average. "With China accounting for more than half the total world increase, it is hard to see much slowdown, even with more recent declines in Eurozone and US consumption," said David Wyss, Standard & Poor's chief economist.

Nariman Behravesh, chief economist at Global Insight Inc., Waltham, Me., expects crude prices to hit $160/bbl by December and remain high for 6 months before falling as global demand eases. "First and foremost, the growth in both real gross domestic product and energy demand in emerging markets is likely to remain strong for some time," he said. "While some countries are beginning to tighten monetary policy and some are cutting fuel subsidies, these moves have been modest and are unlikely to have any significant impact until late 2009 or 2010. In the meantime, strong energy demand growth in emerging markets will outstrip additions to non-OPEC supply and will offset the declines in demand that have already occurred in the US and Europe," said Behravesh.

Global Insight raised its estimated peak price for West Texas Intermediate to $160/bbl from $124/bbl previously. It expects the price to drop to $130/bbl by the end of 2009 (compared with $111/bbl in the prior forecast) and to $105/bbl by the end of 2010 (unchanged). But conflict between Israel and Iran and more supply disruptions in Nigeria could push prices higher, Behravesh said.

Fortunately, energy is a smaller part of the US and world economies than it once was, said S&P's Wyss. "Even this year, we expect the average US household to spend 6.7% of its income on energy, which is about the same as in 1971." In 1980 and 1981, energy was 7.9% of income, reflecting a greater efficiency in energy use relative to gross domestic product, he said. Even so, per-capita use of energy has increased. "In the US, higher per-capita GDP has increased energy use per person by 2% (1971 to 2005). Worldwide energy use per head has risen 15.7% (1971-2004). "The average American used 4.7 times as much energy as the average for the world in 2005 and nearly twice the average of Western Europe and Japan," Wyss said.

Sword rattling

If attacked, Iranian forces would impose controls on shipping in the Persian Gulf and the Strait of Hormuz, said the head of Iran's Revolutionary Guards. However, at a gulf naval security meeting in Abu Dhabi, Vice-Admiral Kevin Cosgiff of the US Navy's Fifth Fleet, said, "Iran will not attempt to close the Strait of Hormuz and we will not allow them to close the Strait of Hormuz. I can't say it anymore clearly than that."

Despite widespread speculation about possible Israeli plans to bomb Iran's nuclear plants, analysts at Friedman, Billings, Ramsey & Co. Inc., Arlington, Va., remain skeptical. "We would be cautious before interpreting the July 5 Israeli Air Force drills over the eastern Mediterranean Sea as a practice run for a bombing campaign against Iran," FBR analysts said. "We concede the exercises superficially resemble Israel's practice runs with its [then] newly acquired F-16s prior to the successful 1981 bombing of the Iraqi Osirak reactor at al-Tuweitha."

However, they said, the latest drills may have been only a sword-rattling warning to Iran as well as a political maneuver for Israeli voters. "With Prime Minister Ehud Olmert's Kadima party primaries scheduled on Sept. 25 and general elections possible in November once the Israeli parliament returns from summer recess, it should not stretch US investors' credulity to imagine that incumbents want to look tough on security," the analysts said.

Iran may be using today's "robust communication infrastructure" to "scare up" the price of crude while also permitting the US and Iran to engage in "megaphone diplomacy" via public statements reported in the media, despite the halt of official relations 3 decades ago, analysts said. Any price premium for the escalated risk of a disruption of crude exports from Iran may already be imbedded in current prices, they said.

Meanwhile, Russia is revising its combat training programs for military units that might be deployed in the Arctic in case of a potential conflict. It began preparing for an Arctic war after the US, Canada, Norway, and Denmark contested its claim last year to a large area of the Arctic shelf thought to hold vast mineral resources.

(Online July 7, 2008; author's e-mail: samf@ogjonline.com)

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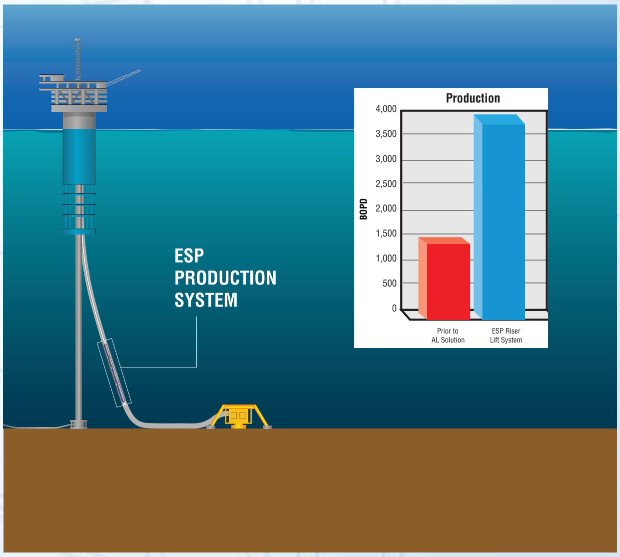

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CAMEROON:

MAXIMIZING ITS ENERGY POTENTIAL

>>>>>>>>>

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Interview with
H.E. Mr. Inoni
Prime Minister of Cameroon

Q: Historically, there has been a very strong relationship between public sector electricity demand and the growth of the GDP. They are obviously very closely intertwined. Do you see the GDP fueling the demand for energy resources or the improved energy resources vital to improving the GDP of the Republic?

A: Yes, I think the two are related and connected to each other. If we want to increase our GDP, the energy demand is going to be greater and so the production has to increase. At the moment, the total demand is between 600 to 700 mw. We are looking at producing about 1000 mw from next year. This is acceptable in the meantime, but in about five years from now, we might need 1500 mw. Therefore, we have to make sure that we increase our production.

The production today is still not sufficient even for domestic and industrial consumption. If we want to increase our industrial capacity, we have to increase the production of energy. We are looking at building dams in Lom Pangar, Nachtigal and Memve'ele. These are going to take a few years to start functioning, so we are trying to put up a gas plant at Kribi to generate electricity. But the problem that we face is that most of the electricity that is produced in Kribi is required by the aluminum industry that is in Edea. Almost half of what is to be produced is going to be consumed by this industrial unit. So, our energy demands will still not be completely met but we still hope that it will help us reduce the shortage that we are experiencing now. By 2010, Memve'ele is supposed to be ready and by 2011-12, Nachtigal and Lom Pangar should be operational. Through these operations, we may cover our total needs but this is dependent on how much and how fast the economy grows and what the demands of the industrial sector are.

Q: Obviously the oil reserves in the country and the untapped oil reserves have the potential of fueling the country's future demand and there are also several wells identified in and around the Bakassi peninsula. What is the strategy and licensing plans for the area?

A: We have just come out of a boundary dispute with Nigeria. We are happy that this issue has been finally resolved. We are now going to start exploration in the Bakassi area. There are stories about discoveries that have been made in Bakassi but there is no conclusive proof yet. SNH is signing contracts with some companies to carry out offshore and onshore explorations in the area and only after we receive the reports from these companies will we be able to ascertain whether there is oil in Bakassi or not. I read a confidential report about five years ago which said that most of the countries around the Gulf of Guinea will increase their production but Cameroon's production would be zero by 2015. Contrary to that, we are now hopeful that instead of being a net importer of oil, we will probably see some increase in our production. So, there is going to be a lot of exploration in the area but we cannot say for sure that discoveries will be made.

Q: Do you see any other challenges to the stability of the region? The border dispute with Nigeria has thankfully been resolved and we are very happy about *that. Are there any other challenges to the stability of the region?*

A: Yes, there are quite a lot of challenges. Let me give you an example of the north. There are no real boundaries in the north. It is very difficult to control the border up there. The terrain is such that even without building roads people can drive through the border. Take for example the Lake Chad, 50-60 years ago, which covered a surface area of 30,000 square kilometers. Today, it is less than 3000 square kilometers. It is drying up and moving from west to east. Nigerians who lived on the western bank of the lake and whose occupation is fishing followed the water as the lake was drying up. They, thereby, ended up in Cameroon without knowing.

This is partly how the border problem originated in the north. In the south, Calabar is one of the ports of Nigeria but it is always silted. For vessels to get into Calabar, they have to enter, using the eastern part of the estuary, thereby, using the Cameroonian side.

Q: Coming back to the oil and gas sector, what do you think foreign firms can bring to Cameroon's oil and gas sector and what can Cameroon give to foreign firms in return?

A: The oil and gas sector is completely liberalized and we welcome any company that wants to come here, if they respect the conditions. Today, we have five French companies here. We have Exxon, Texaco, Total and others. So, you can see that we are completely liberalized. One thing that makes us different from other countries of the region is that we have had a long experience in this area. The kind of contracts that are signed between us and the oil companies do not have the same terms of agreement. Another fact is that our country is stable. Oil companies are huge multinationals who invest so much that they do not want to do so in unstable areas. Cameroon is attracting a lot of investment. People like to invest here because our policy is liberal and other factors are favorable and we have very good relationship with these companies.

Q: Moving on to the Port of Limbe, President Biya has highlighted Port Limbe as a priority for the Government of Cameroon. How important do you think that is to attracting foreign trade to Cameroon?

A: The Port of Limbe is a very important project for us because the port of Douala is very expensive now. It is always silted and we have to dredge it all the time. Transportation is done with vessels which have certain capacities and some of those

H.E. Mr. Inoni, Prime Minister of Cameroon

cannot get into Douala very easily. Getting smaller vessels into Douala is very expensive. We need a deep sea port in Limbe or Kribi. Some years ago, there were studies done by an American company that placed Limbe in a good position as compared to the Ports of Togo and others in the region.

Limbe is well positioned because there is no silt here as it is in a volcanic area. If you have, for instance, a depth of 12 kilometers, it is 12 kilometers all the time. The depth is, therefore, never in doubt and this is the advantage of Limbe. The thought at that time was that Limbe would be a big port and serve as a hub for the central and probably western regions of Togo. This is still what we have in mind and that is why we have to build this port as soon as possible. We are working with a company from Miami, Florida. It is not in conjunction with SNH but with the shipyard, CNIC. Eventually, there may be a railway link between Douala and Limbe. Let's me also mention that the studies for the building of the port of Kribi are completed and we are looking for funding.

Q: In relation to the energy sector, what do you see as the primary objectives for your government now and in the future?

A: One of the primary objectives is that we want to diversify our resources. That is why we are trying to develop the bio-fuel project. Hydro electricity, for us, is cheap but the investment is heavy. We are also going to use natural gas. We also want to improve the transportation network; that is, the transportation of energy from the source to the consumer. AES Sonel is working on the equipment that is 20-30 years old and needs updating. So, we have to modernize the equipments and improve on it. We also want to transport energy, thereby reducing cost and making it available to the ordinary Cameroonian. We are working on a project with the Rural Electrification Agency. With regard to solar energy, we have proposals from certain companies. So, our priority is to diversify as much as possible.

Q: Is there any personal message that you would like to convey to the readers of the oil and gas journal?

A: The message is simple. Cameroon is in the region of Central Africa and occupies a strategic position. It is also the motor of the sub regional economy and enjoys stability. Since our independence, we have been stable and this is crucial for development. I have always told people that Cameroon is "Africa in miniature". It is a junction. It is also a cultural bridge. Some people think that Cameroon is French speaking whilst others think that it is an English speaking country. It is neither. It is Cameroon and that is it. We are the link between the French and English speaking parts of Africa. There are people who think Cameroon is in West Africa whilst others think it is in Central Africa. This is the place to be. For any investor, all the prerequisites are here and there is no reason why people should not invest. The security risks are minimal and the economic advantages are there.

Cameroon occupies a strategic position and it is also the motor of the sub regional economy. In addition, we enjoy stability and provide a junction and cultural bridge for many nations. For this reason it is the place to be.

H. E. Mister Inoni, Prime Minister of Cameroon

Cameroon's Petroleum Resources:

Gas prospects, offshore opportunities, location are key assets

As oil and gas demand continues to grow, two things will follow. Discovered reserves will become more valuable and incentives to explore for additional supplies will become increasingly attractive.

Though Cameroon's proved oil and gas reserves, estimated at the beginning of 2008 at 200 million bbl by *Oil & Gas Journal*, are modest on a worldwide scale, the country's potential—especially for the discovery of natural gas—is significant. And Cameroon's strategic plans are designed to exploit that potential to benefit its citizens, and local and international investors.

Compared with the previous year, oil reserves declined due to production and the absence of significant discoveries, while gas reserves increased. *The Journal* estimates 2007 production at 84,000 b/d, down about 4% from the year before, but a significant increase from 2004.

According to the US Energy Information Administration (EIA), Cameroon's 2007 petroleum consumption was about 24,500 b/d, leaving more than 60,000 b/d for export. Exports have increased from a low of about 43,000 b/d in 2004, according to EIA.

Because current oil production is modest and existing fields are declining, much of Cameroon's petroleum story is about potential, especially the potential of prospective natural gas deposits. And much of the country's petroleum promise lies offshore.

To convert potential to reality, plans are being developed to expand oil and gas exploration and production activity, upgrade refining capacity and increase electricity generation capacity, all to fuel the country's economic growth.

Significant natural gas prospects can help expand the country's power generation capacity, which stood at about 0.9 gigawatts in 2007, up from 0.6 gigawatts in 1995. And upgrading and expanding Cameroon's single refinery can reduce dependence on imported light oil and meet growing product demand. The refinery's capacity was about 42,000 b/d in 2007.

The oil challenge

Currently, Cameroon's oil production comes from fields in the later years of life and few new significant discoveries have been made in recent years.

In the case of Shell subsidiary Pecten Cameroon Ltd., which began development of oil fields in the Rio Del Rey basin, the decline in oil reserves is normal for production that is 25 years old, said Mr. Ruud Schrama, until recently President and General Manager, Pecten Cameroon.

The Mokoko-Abana has been producing for 25 years, as has the Rio del Rey, operated by Total Cameroun. The opportunity to apply breakthrough technology in such fields is limited, said Mr. Schrama. "As production declines, of course, we evaluate the possible application of the latest advances in technology. However, the scale is fairly

Noble Energy inc. A rare double flare on the SEDCO 700. The first deep water well in Cameroonian waters.

limited here. It's not a place where we can experiment a lot."

"What we require is not 'rocket science' but sufficient 'barrel chasing.' We do that by getting people on the ground that are competent," he said. In doing so, Pecten has been able to slowly pick up production in its operating areas. "By tweaking every valve, we have been able to increase production by about 10%."

Despite some discoveries, Mr. Schrama sees no real evidence that a 'game change' is in store for Cameroon's oil production. "When you move from the southwest to the northeast of the country, the reservoirs that contain oil become lighter and gassier." Farther north, more gas fields have been discovered than in the south.

"We are in a declining oil basin and we try to guard it properly," he said. "We try to 'find' the ever-smaller volumes which are still out there by re-interpreting the reservoir models."

However, in the long term—say out to 2020—it is possible that Cameroon would want to continue to produce oil from these fields, even after they have become sub-economic, because they enjoy strategic advantages, according to Mr. Schrama.

Since existing reserves are declining, it is important to find ways to develop smaller volumes. "Oil still has many years to go," he said, "if we can manage the ever-smaller margins in a smart fashion."

There is still some oil exploration activity, and there may be opportunities at greater depths.

The business environment has also changed. 1998 was a bad year for oil prices, slowing industry activity. "Everyone was looking at new prospects rather than the production of more barrels," said Mr. Schrama. With today's improved business environment, Pecten has been increasing investment levels, making use of the latest available proven technologies.

"Since 2006, we have drilled three wells after a drilling holiday of a couple of years. We are planning to drill additional wells next year."

It is a challenge to make the business work in an environment where the oil fields are small and somewhat scattered, but still contain serious volumes.

"Being nimble here is the key to success," said Mr. Schrama.

Bakassi prospects

With the resolution last year of a boundary dispute with Nigeria, exploration in the Bakassi peninsular area can begin, said Prime Minister Ephraim Inoni in a recent interview. He expects significant exploration activity in the area.

"There have been hints of discoveries in the area, but no conclusive proof," said Prime Minister Inoni. "Cameroon state oil company Société Nationale des Hydrocarbures (SNH) is signing contracts with companies to carry out offshore and onshore explorations in the area. Only after we receive the reports from these companies will we be able to ascertain whether there is oil in Bakassi or not."

Mr. Schrama discounts earlier speculation about oil in Bakassi, because the trend indicates a greater likelihood of gas in the area. "There is no indication from the trends, map, geology and the way development has progressed that there is a big oil field there, unless there is something at a different depth that has not been tested in the last 10-15 years."

Pecten does have a 25-year partnership with Total in these areas, and drilled a number of wells that it no longer operates. Volumes that have been identified have not been commercial with the exception of some production that is sent to a neighboring block or facility. The areas developed by Pecten and operated by Total in the north have not been very active because of the border dispute.

Strategies to reverse the oil production decline should include encouraging interest in a new round of exploration, said Mr. Ibrahim Talba Malla, Director General, Caisse de Stabilisation Prix des Hydrocarbures (CSPH). Exploration should be accelerated in Bakassi, he said, now that the border dispute is resolved.

Tullow seismic boats, Ngosso permit, Rio del Rey Basin.

Natural gas potential

Cameroon has recognized the potential of its natural gas resource for several years and recently has taken demonstrable steps through SNH toward its development.

Perenco Cameroon S.A. operates Sanaga Sud gas field, Cameroon's largest. Development has been accelerated in order to provide natural gas to fuel a power plant in Kribi to be operated by power company AES-SONEL. Initially, the largest customer will be AluCam, Cameroon's aluminum smelting company.

"The Sanaga Sud field is not a field that a single party can develop with an adjacent scheme but requires gathering, collection and redistribution," said Mr. Schrama.

Cameroon's ambition is to develop its gas resources, fuel the power station, and have a significant volume left to be converted into liquefied natural gas (LNG). Potential gas supply is larger than that needed for expected power generation demand. Part of the excess will be converted into LPG and the remainder will go to an LNG facility in Equatorial Guinea.

"The challenge of this project is that it has to lean on so many players and depend on so many small fields to come on-stream. It is not a trivial project," said Mr. Schrama.

Offshore activity highlights

Much of the opportunity for new discoveries in Cameroon lies offshore. And several companies have recently completed work and announced new plans.

Perenco's exploration activities have been focussed on the onshore Kombe-Nsepe license, with partners Kosmos Energy LLC and SNH, and on the deepwater Ebodje license, according to company information. Two prospects will be drilled on Kombe-Nsepe in 2009. A deepwater well on the Ebodje license has demonstrated the presence of all the elements of a hydrocarbon system, according to the company, and discussions are on-going to enable additional exploration investment in this play. Perenco is also evaluating a number of gas opportunities that may add value to the development of the Sanaga field.

Late last year, Noble Energy Inc. announced a new discovery on its offshore PH-77 license, between Cameroon and the international boundary with Equatorial Guinea. The license area contains a number of seismically identified prospects, according to the company.

Located in 1,732 ft (528 m of water), the well's primary target in the Miocene was the YoYo-1. A high quality Miocene reservoir containing 95 ft (29 m) of net hydrocarbon pay was encountered in the YoYo-1 interval, the company said. Production tests yielded flow rates of 330 b/d of condensate and 31 million cu ft/day (MMcfd) of natural gas, with production rates limited by test facilities. The interval was encountered at a depth of 8,425 ft (2,568 m). Additional appraisal work will be necessary to verify the areal extent of the YoYo-1 discovery, the company said.

In a secondary, deeper target in the Paleocene, commercial hydrocarbons were not found, according to Noble Energy.

Other participants in the PH-77 license area are SNH, and Petronas Carigali Overseas Sdn. Bhd., a wholly owned subsidiary of the Malaysian national oil company, Petronas.

Addax Petroleum Inc. planned to complete its first two exploration wells at the Ngosso block offshore Cameroon in the first half of 2008. The first of these wells, spudded in early March, targets the Odiong prospect. The company has extended its contract for the jack-up drilling rig Hercules 156, used on the first well, to early 2009 to support its accelerated exploration program.

Addax, with 60% interest, operates the 474 sq mile Ngosso license in the Rio del Rey Basin; Tullow Oil Co. holds 40%. The shallow water off northern Cameroon contains a number of small oil discoveries, and offers exploration opportunities, according to Addax.

The exploration well that had a gas kick last year while Bowleven plc's wholly-owned subsidiary, EurOil Ltd., was drilling in Block MLHP 7 of the shallow water Etinde permit was abandoned after taking the kick. Primary objective was the gas/condensate bearing Isongo sands at a depth of about 10,000 ft (3048 m).

The kick occurred about 540 ft (165 m) above the highest expected target in the uppermost section of the Isongo. For safety reasons, and to develop a new well design using higher-rated equipment, the well was abandoned. In early February, Bowleven signed a contract with Sedco Forex International Inc. to re-drill the IF exploration well with the jackup rig Trident IV. Operations were scheduled to begin in late April or early May.

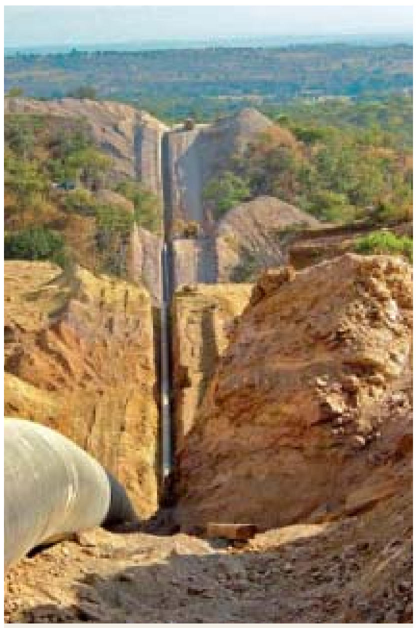
A strategic pipeline

Aside from its petroleum and human resources, Cameroon benefits from the strategic value of the Chad-Cameroon pipeline. The pipeline is one of Cameroon's successes in uniting international investment through the cooperation of two neighboring countries within Central Africa.

Operated by Cameroon Oil Transportation Co. (COTCO), the pipeline transports oil from the Kome area and the fields located in Chad to Kribi. The oil is stored offshore near Kribi in a floating storage vessel where tankers load for export.

"COTCO's role is to ensure that the pipeline works smoothly and reliably," said Jacky Lesage, General Manager, COTCO.

Design capacity of the line is 225,000 b/d. In mid 2007, throughput was close to 140,000 b/d. At that time, Mr. Lesage expected throughput



Chad-Cameroon pipeline construction phase.

to increase by the end of the year to 170,000-180,000 b/d as a result of some new fields being brought into production in Chad.

Along with petroleum products, the pipeline also carries a fiber optic system for high speed communication.

"When we laid the pipeline, we felt the need for the fiber optics to be installed and decided to include 12 fibers for the exclusive use of the Cameroon government," said Mr. Lesage. "Installing 1,000 km of fiber optic is a significant achievement, and it will constitute the back-bone of the fiber optic infrastructure in Cameroon." The project also brought other infrastructure improvements, including roads in the north of Cameroon and bridges. Three of those bridges were turned over to the Government last year. Significant work was also done during the project to upgrade the railway and locomotive sectors, according to Mr. Lesage.

Some work also had been done on the Kribi air strip during the construction of the pipeline in 2004 and the airstrip located in Belabo was refurbished.

Currently there are no expansion plans for the pipeline, but COTCO is open to opportunities to enhance its role in Central Africa. "For the time being, COTCO's sole objective is to transport oil through the pipeline from Chad," said Mr. Lesage. "This is part of the role of COTCO by law and is part of the Convention agreement."


Welder working on the Chad-Cameroon pipeline.

Should a new customer request access to the pipeline, it must be pursued through the legal framework. "We can work with any customer who asks us to transport oil through the pipeline," he said.

In early 2008, COTCO had no plans to build a new pipeline, for example, to link the existing line with Gabon or Nigeria. But if another pipeline is built and linked with the Chad-Cameroon pipeline under existing agreements, of course, COTCO would accept the new customer, said Mr. Lesage.

"We do not have the ability or willingness to design, develop and implement another pipeline," said Lesage.

The Chad-Cameroon pipeline has also been a benefit to Cameroon's economy. In 2006, COTCO spent a substantial US$40 million locally. The company spends close to $600 million locally in Cameroon each year, according to Mr. Lesage.

Most of this pays contractors that work for the pipeline. In addition, COTCO also pays a transit fee to Cameroon, which in mid 2007 had reached about $80 million since the beginning of the operation.

"But I call that our modest contribution, as part of the oil industry within Cameroon," said Mr. Lesage.

COTCO has a number of international partners that are concession operators. In Chad, there are three: ExxonMobil Corp., Chevron Corp. and Petronas. The other partners are the Republics of Chad and Cameroon.

"I also consider the World Bank and other lenders to be partners," said Mr. Lesage. The World Bank was a key driver of the project; nothing would have happened if the World Bank had not approved the project, he said.

"In total, there are 18 lenders. These 'partners' are very important, even if they are not shareholders."

High Quality Exploration Opportunities:

SNH and its partners intensify exploration, plan emphasis on gas development

Global energy demand will bring new opportunities for countries that have significant oil and gas prospects, and a strategy that is grounded in market realities.

In this environment, the Republic of Cameroon has the potential to play an important role in the world's energy markets, while it fuels the growth of its own economy and advances the living standards of its citizens.

In his year end speech last December, Cameroon President Paul Biya described the country's energy goal this way:

"Our most urgent challenge should be to increase energy supply in order to meet the increasing needs of the population and the demand of enterprises."

Today's Republic of Cameroon enjoys a stability that will facilitate the further development of its petroleum industry. According to the U.S. Energy Information Agency, Cameroon's economy has grown steadily since the mid 1990's and 2005, the real GDP growth rate was 2.6%.

Experience in producing hydrocarbon resources, tempting exploration prospects, and a strategic location together provide a promising future for oil and gas development in Cameroon.

SNH has key role

Central to the country's future is its national oil and gas company, Société Nationale des Hydrocarbures (SNH). The company engages in partnerships with international oil companies, assists the government in its financial relations with private oil firms and is responsible for selling the government's share of oil output. SNH also holds stakes in companies involved in downstream activities and in non-oil-related activities.

The company fully shares the priority described by President Paul Biya, said Adolphe Moudiki, SNH Executive General Manager.

One of its key roles will be to guide Cameroon's focus on natural gas. To that end, the SNH Board of Directors in June created a Gas Directorate to implement the Master plan for the development of gas resources.

Hydraulic workover unit on Bravo platform.

A key project is the construction of a gas plant at Kribi, of which SNH is a stakeholder. In 2006, Perenco Cameroon S.A signed a 25-year contract with SNH to develop the offshore Sanaga Sud natural gas fields in the Douala/Kribi-Campo basins to supply gas to generate power at the Kribi plant.

Perenco's conceptual studies for the development of the Sanaga Sud fields have been completed. Preliminary engineering will be complete by the end of this year, and gas is expected to be available for the plant in the first quarter of 2009, said Mr. Moudiki.

The contribution of SNH to Cameroon's economy is significant. In the first quarter of 2007, the company's income exceeded projections by 13.4%, according to Mr. Moudiki. For the period, SNH transferred 119,943 billion Francs CFA to the public Treasury, not including taxes.

Crude oil production during the period dropped slightly due to operating problems. Oil output was 83,604 b/d as of May 31st, compared to 87,357 b/d at year end 2006. Much of Cameroon's crude is heavy; lighter production is used domestically, while the heavy crude is exported.

Foundation for growth

In a sense, the main thrust of the development of Cameroon's oil and gas resources has just begun. Though all three of the country's main petroleum basins have been explored, new partnerships with international companies promise a much more intense search of large prospective areas.

Elf Acquitaine conducted the first oil and gas exploration in the country in the 1950s, concentrating on the Douala Basin. When other companies joined the search in the late 1960s, the focus shifted to the Rio del Rey Basin where discoveries in the 1970s included Asoma, Bavo, Betika, Ekoundou, Kole, Kombo and Makoko.

Production from these discoveries began in the mid 1970s and oil output reached a peak of more than 150,000 b/d in the mid 1980s. As Rio del Rey production declined, more exploration in the Douala Basin turned up gas condensate discoveries including Batanga, Benda, M'Via and N'Koudou.

Development of the Kribi-Campo area began in the 1990s, and the Ebome field went on stream in 1996. In the late 1990s, Shell subsidiary Pecten Cameroon Ltd. began development of oil fields in the Rio Del Rey basin.

In addition to its own hydrocarbon resources, the Chad to Cameroon oil pipeline and the export terminus at Kribi will help Cameroon become a significant regional oil transportation hub.

In downstream activity, a 42,000-b/d refinery at Limbe operated by the Société Nationale de Raffinage (SONARA) will get significant upgrades to increase capacity and handle more of the country's heavy crude.

Offshore oil platform.

Resource potential

According to the *Oil & Gas Journal*, Cameroon's proved oil reserves were estimated at 400 million bbl at the beginning of 2006. Most reserves are located offshore in the Rio del Rey basin. Smaller deposits are located in the Douala/Kribi-Camp basins off Cameroon's western coast, and onshore in the northern Logone-Birni basin.

"The contribution of SNH to Cameroon's economy is significant. In the first quarter of 2007, the company's income exceeded projections by 13.4%."
Adolphe Moudiki, SNH General Manager

Cameroon does not produce natural gas, but the new Gas Directorate within SNH will focus on its significant prospects for development. SNH estimates proven natural gas reserves in Cameroon at 157 billion cu m, with a potential of 570 cu m still unexploited. The majority of the resource is located in the Rio del Rey, Douala and Kribi-Campo basins.

Renewed interest in oil investment has led to new exploration in all three of Cameroon's major petroleum basins and SNH believes that discovery and development of smaller fields is still possible.

According to a report on the website *Mbendi*, the Douala/Kribi-Campo Basin comprises part of the greater West African Margin Basin system and is the northernmost of a series of genetically related basins that stretch from Walvis Ridge to Cameroon.

In the Douala Basin, turbidites and deep sea fan deposits comprise the Upper and Lower Cretaceous reservoir sequences, although in the latter, fluvial and alluvial reservoirs have also been encountered, said the ***Mbendi*** report. Shallow water deltaic Tertiary deposits are also potential reservoirs in the shallow water areas of the basin.

The Logone-Birni Basin comprises part of the West and Central African Rift systems, in which the main source rocks are the oil prone lacustrine deposits in the Lower Cretaceous Aptian-Albian rift fill. The Tertiary, Upper and Lower Cretaceous in the Basin all have good potential for porous clastic reservoirs, according to *Mbendi*.

Exploration and production

To accelerate the search for new reserves, the Cameroon government revised its petroleum laws in both 1999 and 2002 to include financial incentives and tax breaks for exploration.

West Africa offers multiple high-quality exploration opportunities, according to Kosmos Energy Cameroon HC. Reserve and production growth rates in this prolific area are high and finding and development costs in the region are very competitive.

The company plans to pursue primary exploration plays in frontier, emerging and established basins in deep water, as well as secondary exploration of new plays in developing and mature basins in shallow water and onshore.

Total

In 2005, SNH awarded the first production sharing contract (PSC) in Cameroon's history to a subsidiary of Total S.A. Total E&P Cameroon was awarded the Dissoni permit in the Rio del Rey basin. Total found oil after drilling its first well on the block. The Dissoni permit, owned jointly by Total Cameroon and Shell subsidiary Pecten Cameroon Ltd., adjoins other concessions operated by Total and covers 143 sq km.

In early 2006, Total was awarded the Bomana offshore exploration block in the Rio Del Rey basin. The company is 100% owner of the 140-square-kilometer block.

The Bomana acquisition advances Total's strategy in Cameroon to pursue opportunities to increase its present acreage, a strategy that began when the group was awarded the Dissoni block.

At the time of the award, the Total/Pecten/SNH group's operated production in Cameroon was about 60,000 bopd.

Noble Energy

Noble Energy, Inc.'s wholly owned subsidiary, Noble Energy Cameroon Ltd., acquired a 50% working interest in the Nyong II (PH-77) license offshore Cameroon in the Douala/Kribi-Campo basin in 2006 and operates the concession. Malaysian national petroleum company Petronas is the other partner in the license. SNH may assume a 50% participating interest upon a commercial discovery.

PH-77 covers 1.125 million acres between the Cameroon coast and the country's international boundary with the Republic of Equatorial Guinea.

Noble has interpreted 18,000 km of 2D seismic and 2,900 sq km of 3D seismic to evaluate the basin's potential, that estimates the license contains a number of seismically identifiable prospects. The basin is under-explored and has large prospects significant potential, the company reported in a presentation at Lehman Brothers CEO Energy/Power Conference in September.

At the time, the company was drilling the YoYo/Pilar test in the permit. The block has a number of prospects that are seismically similar to Noble's discoveries and prospects in its adjoining Equatorial Guinea blocks offshore Bioko Island.

Noble Energy also has pledged to invest in projects identified within the framework of the master plan for development of Cameroon's gas resources.

Perenco

Perenco has operated in Cameroon since 1993, together with ExxonMobil Corp. and SNH. Perenco's principal assets in the country are the Moudi and Ebome Marine concessions, and the Ebodje deepwater exploration permit. The company's production area covers 967 sq km and it holds 5,182 sq km of exploration acreage.

As part of an overall program to optimize production, Perenco has upgraded the Moudi field with water injection and sand control systems. Renovations to the main production platform are also planned to maintain total gross production at 4,000 bopd.

At its Ebome Marine block, gross production has been maintained at 10,000 bopd since the discovery of KF field in 1997.

Perenco recently drilled a CM-1A well within the Ebodje deepwater exploration permit, and has several promising exploration prospects currently under review.

Addax/Tullow

In December 2002, Tullow Oil Co. and Addax Petroleum Cameroon Ltd. signed a contract with SNH for exploration in the Ngosso area of the Rio del Rey Basin. Addax operates the license with a 60% interest; Tullow holds the remaining 40%.

The concession in shallow water off northern Cameroon covers an area of 474 sq miles (117,100 acres) that contains a number of existing small oil discoveries, including Narendi, Odiong and Oongue, in addition to numerous exploration opportunities.

During the first three years of the contract, the minimum work commitment required the acquisition of 200 sq km of 3D seismic and the drilling of two wells. The agreement also offers incentives for developing marginal fields with oil reserves of less than 20 million bbl. The 3D was completed in the first quarter of 2006 and the drilling is planned for late 2007.

According to Addax, Ngosso, which lies adjacent to the shore, has similar operational and subsurface geological conditions to the OML123 block in Nigeria. Though the area contains several discoveries, it has not seen any exploration for 20 years.

Addax estimates the Ngosso concession may contain as much as 47 million bbl of recoverable oil reserves.

Kosmos Energy

Cameroon offers the opportunity to explore the extensions of proven petroleum systems inboard and onshore the Douala and Rio Del Ray basins. The company is focusing on under-defined and under-explored Early Tertiary and Upper Cretaceous structural/stratigraphic fairways either up-dip of producing areas or along trend from recent discoveries.

Oil is targeted but emerging gas commercialization options potentially manage phase risk.

In a presentation to the 3rd Annual Africa Petroleum Forum in London in April 2006, Brian F. Maxted, Partner, Kosmos Energy, highlighted the company's Cameroon properties and prospects.

The company's two assets in the country, Kombe-Nsepe and N'Dian River, are characterized by:

- Proven petroleum systems inboard and onshore Douala and Rio Del Ray basins featuring about a dozen discoveries—mainly oil—and high technical success rate;
- Under-defined and under-explored Upper Cretaceous and early Tertiary structural and combination plays; in Cameroon, only 30% of wells are designed to test the Upper Cretaceous.

The N'Dian River license provides the opportunity for exploration of deeper, Upper Cretaceous structural oil plays, as well as shallower Tertiary stratigraphic gas/condensate plays. The company's initial focus will be on the N'dian River Block's under-explored northern extension of the late Cretaceous/lower Tertiary turbidite play, which has been successful in adjacent regions. During late 2007 and early 2008, Kosmos plans to conduct a 2D seismic

Bravo platform.

survey on up to 400 km as part of the seven-year exploration agreement, also part of the work obligation is an aeromagnetic and gravimetric survey on the block.

After processing and interpreting the seismic data, Kosmos Energy expects to drill an exploratory well.

Kosmos is 100% owner and operates the N'dian River Block. The PSC covers about 2,510 km2 (620,000 acres). Partner SNH was to be carried through exploration and appraisal phases and have an option to back in to the project with an interest of up to 15% upon approval of a development plan.

The block comprises a portion in the transition zone east of the Bakassi peninsula, and an onshore portion adjacent to the crystalline basement farther to the east. There have been several geophysical and drilling activities on this block in the past. The latest of three wells, Munge, drilled by Elf Serepca in 1997, had oil and gas shows. But the block has had no significant exploration activity since 2001.

Kosmos has a 35% working interest and Perenco operates the Kombe-N'sepe Block, a coastal strip of Douala Basin bordering Gulf of Guinea (predominantly onshore), containing about 3,026 sq km (748,000 acres). Perenco has a 40% working interest and SNH, 25%.

Kombe-N'sepe is at the northern end of the late Cretaceous turbidite play fairway that extends from northern Gabon through Equatorial Guinea into southern Cameroon. More than two billion bbl of oil have been discovered in the region.

Generally, explorers have not focused on this late Cretaceous play where Kosmos Energy recognizes several promising leads in stratigraphic pinch-out and combination structural traps located in well-developed channel systems.

In late 2006, Kosmos Energy and its partners acquired 2D seismic data to refine understanding of the block's prospects and help define the location of the first exploratory well.

BowLeven

BowLeven plc's wholly-owned subsidiary, EurOil Ltd., is 100% owner of the Etinde Permit area comprised of three shallow water offshore blocks—MLHP 5, MLHP 6 and MLHP 7.

In total, BowLeven has about 2,300 sq km of exploration acreage located across the Rio del Rey and Douala basins in the permit. According to the company, the acreage has very attractive exploration potential.

The company has operated in Cameroon since 1999 and over the years has established a strong relationship with the Cameroon government. During 2007 the company planned to:

- process and interpret 3D seismic data on the Etinde permit;
- drill up to four exploration and appraisal wells:
- continue to consider opportunities for timing on a farm-out;
- monetize its existing resource base together with any additional gas/condensate discoveries;
- augment the existing asset base through selective acquisitions, and;
- further evaluate selected identified prospects, leads and plays.

Drilling began on Isongo E2, the first appraisal well on the existing discovery in Block MLHP7 of the Etinde permit. Objective was to appraise the extent and volume of the Isongo sand in the discovery well E1 and explore deeper sands that were water wet in E1. Target depth was 8,500 ft.

In July, BowLeven completed its development well in Block MLHP 5 of the permit. Well D1 was targeting a Miocene turbidite channel prospect similar to that in a nearby discovery. The well tested both gas and condensate from inter-bedded high quality sands, over a gross measured interval of 75 ft and tested at a rate of 25 MMcfd of gas and 1,400 b/d of condensate through a 1-in. choke.

In July 2007, BowLeven announced that drilling had begun on the IF-1 exploration well in Block MLHP 7 of the permit. Primary objective of the well was to explore for gas/condensate bearing Isongo sands in a structure located up-dip from the adjoining IE field. The well was to be drilled to a depth of about 10,000 ft.

In August, however, the company announced that the well had taken a significant gas kick at 6,355 ft (about 540 ft above the highest expected target) in the uppermost section of the Isongo formation. Pressures encountered during this kick indicated that the well could be in communication with the IE structure, evaluated with well IE-2.

For safety reasons, and to develop a new well design using higher-rated equipment, the well was abandoned. It was intended to return to the IF structure to re-drill this exploration well as soon as practicable. The re-drill will most likely be located down dip from the structural crest (where IF-1 is located) on the flanks of the structure, where more favorable pressure conditions are likely to exist.

The likelihood that the IE and IF structures are connected and have a common substantial gas column is extremely encouraging, said BowLeven.


Supply boat and fast boat Zodiac.


Offshore drilling rig.


Juliet platform and Sil Tide boat.

Hardman Resources

In early 2006, Australia's Hardman Resources Ltd. reported that the Zoule-1 exploration well in production sharing contract C Block 6 was being plugged and abandoned after failing to encounter significant hydrocarbons.

The rig was then scheduled to move to the Dore-1 well in PSC B, Block 4, about 20 km east of the Tiof field and 30 km north of the Chinguetti field in a water depth of about 390 m. The well was to be drilled to a proposed total depth of 2,350 m to target Oligocene-aged submarine channel/turbidite sands as well as encountering the up-dip extension of the Tiof Miocene canyon system.

With the recognition of a number of attractive prospects in the shallower, eastern part of PSC A and B, a rig capable of drilling in shallower water depths than the targets of the 2004 and 2005 programs was required, according to the company. A rig rated for water depths from 100 to 1,500 m was contracted to conduct the PSC A and B 2006 and 2007 drilling campaigns.

Strategic and Tactical Objectives:

Upgrade infrastructure and enhance quality of life

In addition to expanding exploration, increasing refining capacity and adding power generating capacity, Cameroon's strategic and tactical plans also have strong components aimed at improving transportation and communication networks.

Expanding the social, health and environmental protection programs that are already underway will also be keys to the country's economic future.

All these efforts will be facilitated by an increasingly stable business environment that welcomes investment.

Energy, water and electricity are crucial to economic development, said Sindeu Jean Bernard, Minister of Energy and Water. "This Ministry will play a key role in all these aspects of the fight against poverty," he said.

Minister Bernard is also interested in the development of renewable energy technologies. In addition to having less impact on the environment, these technologies could be especially important in remote areas where localized production units could make energy more easily available.

Current business structure

World Bank guidelines have suggested more privatization for industry in Cameroon. Cameroon Petroleum Depot Co. (SCDP) was one of the first companies to be considered for privatization, according to Mr. Ibrahim Talba Malla, Chairman.

Currently, the Cameroon government owns 51% of SCDP and private ownership is 49%. "Even if we sell 5%, I think the private sector can run the SCDP more efficiently," said Mr. Malla. He notes that Cameroon's refining company, Société Nationale de Raffinage (SONARA), is different; state entities have 72% of SONARA. "I think that is too high," said Mr. Talba Malla.

"Energy, water and electricity are crucial to economic development. This Ministry will play a key role in all these aspects of the fight against poverty." Sindeu Jean Bernard, Minister of Energy and Water

The older of two frameworks for foreign participation in Cameroon's petroleum business, the tax-royalty model, is outdated, said Pecten Cameroon Ltd.'s Mr. Ruud Schrama. The new production sharing contract regime established by the 1999 petroleum code, allows the contractor to begin development as soon as commercial discoveries are made. Most of Pecten's businesses are in the tax-royalty regime in which the "contractor" runs the day-to-day business but the state, through Société Nationale des Hydrocarbures (SNH), has a 50% share in the partnership.

"We are in daily contact (with SNH)," said Mr. Schrama. SNH does have shares in Pecten, but the focus of the state company as it governs on behalf of the Republic is primarily on SNH's 50% of the entire portfolio instead of its 20% share of Pecten, he said.

Oil inauguration, Cameroon-Chad pipeline.

Infrastructure needs

Air travel is important to the success of both Cameroon's oil and gas development strategy and the country's economic growth. Progress has been made in enhancing the air travel segment, but more needs to be done, according to Mr. Sama Juma, General Manager, Cameroon Civil Aviation Authority (CCAA).

Last year, the World Bank pledged significant investment in Cameroon through the West and Central Africa Air Transport Safety & Security Project to bring airports in line with international security and safety standards.

Foreign investment in this sector is not well developed, said Mr. Juma. "But the grant of $14.5 million from the World Bank to ensure the security of our airports, increase capacity and train personnel is a major breakthrough."

Part of the grant will go to building airport security fences in Douala and Yaoundé. That is a priority project, said Mr. Juma, because the airport does not have enough personnel to carry out security checks.

The Energy sector has already contributed to the development of the aviation industry. Cameroon Oil Transportation Co. (COTCO)

Ports play a vital role in transport.

and others have helped rehabilitate provincial airports, and COTCO built airstrips along its pipeline to facilitate inspection and maintenance.

Because it uses the Belabo airport on a daily basis, COTCO has made a significant investment there, as well as at Kribi, according to Jacky Lesage, General Manager, COTCO.

Since the country's road network is not well developed, rehabilitation of secondary and third grade airstrips throughout the country would facilitate the movement of people and goods. "We welcome the initiative of the oil companies and others who might want to help us rehabilitate these runways," said Mr. Lesage.

CCAA is drawing up plans for those who might be interested in investing in the air transport infrastructure. "For now, we are looking for partners to come and build the runway, airport building, control tower and other facilities at Kribi airport," said Mr. Juma. Based on the "Build, Operate and Transfer" policy, an investor could operate the airport for some time before giving it to Cameroon.

Since independence, Cameroon has been a member of the International Civil Aviation Organization (ICAO). "We do all we can to ensure that we comply with the regulations set out by the ICAO," said Mr. Juma.

Cameroon has three international airports—Douala, Yaoundé and Garoua. Its four secondary airports are Maroua, Ngaoundere, Bertoua and Bamenda. In addition to the national airline company, Cameroon Airlines, other small charter airlines and local airlines are entering the market.

The port of Limbe is another very important project, said Prime Minister Ephraim Inoni. Currently, the port of Douala is expensive to operate because it must be continuously dredged. Using smaller vessels adds to the expense.

"We need a deep sea port in Limbe or Kribi" said Prime Minister Inoni. Limbe is in a volcanic area where silt is not a problem; it could also serve as a hub for the central and western regions of Togo.

Enhancing quality of life

Part of Cameroon's development strategy deals with improving health, safety and environmental protection. COTCO is an example of how energy industry companies can make social, economic and environmental contributions to Cameroon. The company provides work for about 1,200 people on a permanent basis.

"Safety is a top priority and we are very proud of our safety record," said Mr. Lesage. "We just completed four years without lost-time incidents among both employees and contractors."

Through its "roll back malaria" program, aimed at reducing the occurrence of the disease along the pipeline corridor, COTCO has distributed 35,000 mosquito nets along the route. The company also has educational programs on AIDS and an effort underway to fight cholera.

Since the start of the pipeline project, COTCO has provided funds to individuals and communities as part of its responsibility for environmental protection. By the middle of last year, individual compensation totaled about $11 million and community compensation amounted to $5 million. The company has refurbished about 100 classrooms along the pipeline route and continues to drill and upgrade water wells along the corridor.

Downstream Strategy:

Refinery upgrade, expanded distribution network are planned

The responsibility for achieving Cameroon's over-arching goals for its petroleum sector—fueling economic growth and maintaining its energy independence—will depend heavily on the success of its strategy for processing and distributing petroleum products.

Crude production volume, though modest, is twice what the country currently consumes, but the quality of Cameroon's oil is another matter. It is too heavy to be processed by the country's refinery as it is currently configured, so lighter oil must be imported from Nigeria and Equatorial Guinea to feed the refinery. At the same time, most of Cameroon's heavy oil production is exported.

A key goal of the downstream strategy is to upgrade the existing refinery to be able to process heavier crude, reducing the need for oil imports and making the country more self sufficient. Being able to process a wider variety of crude will also enhance the country's ability to become a regional refining leader.

Feeding the refinery with Cameroon's own crude will also help contain costs—both for the refiner and for consumers—as the economy improves.

"Oil is a cure-all—first of all for the general economy, then for the consumer, and finally for the investor," said Mr. Ibrahim Talba Malla, Director General, Caisse de Stabilisation Prix des Hydrocarbures (CSPH) and Chairman, Cameroon Petroleum Depot Co. (SCDP).

For the general economy, the country's downstream strategy will help fight inflation. As energy prices increase, higher transportation and manufacturing costs also raise the price of all goods. The role of CSPH is to help control hydrocarbon prices for the benefit of both the economy and individuals.

"(Consumers) are earning money, and they want to spend less money and consume more hydrocarbons," said Mr. Malla.

SCDP operates 12 storage depots.

A more modern refinery will also position Cameroon as the refining leader of Central Africa and make it possible to manufacture products that meet the quality standards of export markets beyond Africa.

But "downstream" is more than refining; it also includes product storage, marketing and distribution. And expanding and improving that infrastructure is also a key part of the downstream development plan.

It will involve more pipelines, greater storage capacity—both by increasing existing facilities and by building new ones in remote areas—and improved export terminal and port facilities.

This ambitious downstream plan will require significant investment by the country and by outside investors.

"Cameroon has a unique organization of its petroleum industry, particularly in the downstream sector. "Downstream" begins with refining and ends with distribution to service stations."

Dr. Nguini Effa, General Director of SCDP

Unique organization

Among international operators, there are some misconceptions about how Cameroon's downstream operations are organized. One is that SCDP is a corporation that owns petroleum products, but the company is responsible only for operating storage facilities and is not involved in distribution.

Cameroon has a unique organization of its petroleum industry, particularly in the downstream sector, said Dr. Nguini Effa, General Director, SCDP. "Downstream" begins with refining and ends with distribution to service stations."

The refinery and storage facilities are distinct entities in the chain. These typically are owned by semi-public corporations where the state is the majority shareholder. For example, the government owns more than 60% of Société Nationale de Raffinage (SONARA) and 51% of SCDP.

Refined products are marketed in Cameroon by private companies, including Total S.A., Exxon Mobil Corp., Shell Group plc and Chevron Corp.

Storage, distribution needs

An important focus is on storage in new areas after a domestic product shortage in 2007 highlighted the need for expanded capacity. In Yaoundé and Bafousam, for example, the needs of a growing population with increasing demand cannot be well served without more storage capacity because the Douala facility operates at full capacity.

"We have to increase Douala first, then expand in other areas—Yaoundé and Bafousam, and even Ngaoundéré," said Mr. Effa.

SCDP operates 12 storage depots from which marketers take delivery of products. SCDP stores mainly at its depot at Douala

Pump Station, Dompta.

and sends products to depots spread throughout Cameroon, including those in Yaoundé, Ngaoundéré, Garoua and in Maroua.

A national commission sets the terms of the agreements between SCDP and the marketers, according to Mr. Effa. That commission includes representatives from the appropriate ministries, as well as representatives from CSPH, SNH, SCDP and the marketers.

Because the distribution infrastructure needs significant investment, SCDP was one of the first organizations to be put on the list for privatization. Privatization is driven by the need for large investments in the depot network that the state is no longer capable of providing and will have to be made by foreign participants, said Mr. Effa.

Kribi terminal will be expanded in stages, said Minister of Energy and Water Sindeu Jean Bernard. "It is a project that fits into the industrial development plans of the country, and like any large project, it is completed in stages as activity grows."

More investment is also needed for a pipeline from Limbé to Douala, said Mr. Effa. Currently, only one tanker of 15,000 cu m comes from Limbé to Douala every three days and loading/unloading takes one day.

"This is a high priority," he said. "Now that demand is increasing, we cannot meet that demand by shipping alone."

Investment in the pipeline will lower the cost of transportation, as well as reduce the impact of transportation on the environment. Pipeline movement also is more secure and makes access to storage facilities easier.

Refining plans

The refinery at Limbé operated by SONARA is built around a relatively simple processing scheme that limits its capability to handle heavy crude like that produced in Cameroon. The 42,000 b/d plant's key units are an 11,000 b/d catalytic reformer, a 12,000 b/d naphtha hydrotreater, and a 3,500 b/d distillate hydrotreater.

Built about 25 years ago, it was designed to produce the small volumes needed at the time, about 1 million tons of refined products annually. It also was designed to use only relatively light crude.

"Today, the economy of Cameroon has dramatically expanded compared to its size when the refinery was built," said Minister Bernard. "Cameroon's economy is at least 10 times larger than it was at the end of the 1970s, and our need for refined products has multiplied by at least two or three times." Increasing refinery capacity is one objective; another is to always look for renewable energy and cleaner energy forms, said Minister Bernard.

The other part of this reform is to increase the plant's capacity to produce LPG for household consumption. Demand for residential LPG in Cameroon has doubled or tripled compared with consumption during the year the refinery went on line, in part because the government has been promoting the use of this type of fuel for household use.

"We have plans to develop natural gas fields and intend to produce additional LPG through some of those projects," said Minister Bernard.

Being able to process Cameroon's heavier crude and reduce the need to import light crude is a key objective of the upgrade. "It is a good strategy for the state to take its share of the heavier Cameroon crude for its refinery and free up more of the lighter crude for export," said Mr. Ruud Schrama, until recently President and General Manager, Pecten Cameroon Ltd. "An added benefit is that heavier crude reservoirs produce longer than lighter crude fields."

Pecten, like other foreign producers take their crude outside the country for refining.

Charles Metouck, General Manager of SONARA, has a unique view of the economic environment in Cameroon and the positive steps taken in recent years to improve the environment for business.

"More and more, Cameroon is retaking a place in the international business community," he said. "The efforts we are making today will rebuild confidence in the economy of Cameroon that will help re-launch it. Recently, the government has put in place a number of institutional, judicial and regulatory policies that will help the economy advance."

SONARA has a number of important projects in both electricity production and in petroleum. Its key role currently is to operate the Cameroon refinery and serve as the exclusive supplier of fuel for industry, transportation and energy production.

"Our role is to insure energy independence in these areas," said Mr. Metouck. "That also permits Cameroon to be one of the privileged suppliers in the sub-region of Central Africa."

Because SONARA produces about double the country's domestic requirement, it can also help meet demand in surrounding areas, as well as export internationally.

Because the refinery produces much more than domestic needs, there are no plans to build a new grass roots refinery in Cameroon. Rather, reconfiguration of the existing plant will make it more economically viable, said Dr. Yenwo, of SONARA's strategic planning department.

"More and more, Cameroon is retaking a place in the international business. The efforts we are making today will rebuild confidence in the economy of Cameroon that will help re-launch it."

Charles Metouck, General Manager of SONARA

"Being dependent on foreign crude, in particular that from Nigeria, is a problem for SONARA because this limit obliges us to seek out crude that can be processed by our refinery. For some time, we have been considering how to use additional volumes of heavier crude from Cameroon."

Refinery towers.

Workers opening valves.

Refinery and railroad cars.

Cameroon workers play vital role.

SONARA 2010 is the plan that will revamp and improve existing refining units, expand capacity and add the units needed to refine heavy crude from Cameroon and elsewhere. Adding a conversion unit to process the "bottom of the barrel" is a key part of the revamp study. That portion of the crude is currently being sold as atmospheric residue; a new unit will crack this portion to produce additional lighter products and allow the refinery to handle heavy Cameroon crude.

Air and water protection

Environmental protection also drives refinery operation and the design of any new units that are part of upgrading and expansion.

From the beginning, everything was done to protect the environment, said Dr. Yenwo. "For example, every drop of water that falls into the refinery goes into the water treatment system, directed there by the concrete surfaces of the refinery."

The government samples the water that goes into the sea regularly, providing complete data on water discharge from the refinery.

Because the refinery processes relatively light, relatively "sweet" crude, there has been no need for a sulfur treatment plant. "We have very little sulfur and what we do have is transformed into hydrogen sulfide (H_2S) gas and burned in our furnaces," said Dr. Yenwo.

The content of sulfur compounds in the stack gas is insignificant and well within national standards, he said. Cameroon is guided by European air quality standards, since it does not have a specific standard of its own.

On the retail product side, Total has found a way to deal with another environmental challenge in Cameroon. A major marketer in Africa, with activities in more than 40 countries, the company developed the Ecolube process for treating used oil as part of its response to the continent's growing environmental concerns.

As part of the recovery and recycling process, Total Cameroun provides the necessary storage facilities at its own service stations and to large oil consumers. It also collects the used oil and transports it to Douala, where it is blended with heavy fuel oil at the recycling unit to make fuel that is sold to local customers, mainly cement plants. Almost 2,000 metric tons of oil was processed this way in 2006, according to Total. Because the oil to be treated exists in small quantities throughout the region, a facility was installed on the premises of SCDP in Douala.

Ecolub is not a regeneration unit, according to Total. Instead, it recycles used oil by mixing it with heavy fuel oil.

Initially, Ecolub only processed used oil generated by Total Cameroun, about 800 metric tons a year. Now it serves all lubricant

Being able to process Cameroon's heavier crude and reduce the need to import light crude is a key objective. View of refinery by night.

users with a fully-developed policy of product recovery and recycling. Cameroon had the first Ecolube process, but it has now been extended to Madagascar, Burkina Faso and Niger, and is expected to be rolled out in other African countries.

Attracting investment

To meet increasing demand and more stringent standards in the refining sector, as well as throughout the expanding energy sector, initiatives and policies that attract foreign investors will be critical.

SONARA's objective is to position itself as the refining leader of Central Africa, said Dr. Yenwo. "To do that we need investment not only to expand basic capacity, but also to ensure that the quality of our refined products is such that they can be exported within Central Africa and beyond."

Investment is also required in technology that will allow the refinery to process Cameroon crude, as well as imported crude. "This will help build our leadership as a refining leader in the area."

Execution of the plan depends on investment from outside the country. The participation of the International Monetary Fund and World Bank is expected, said Mr. Metouck, but those organizations are still considering the project.

"We expect that the studies we have done for this project, will make clear our interest in investing in a facility that will help us become a leader in the regional energy sector."

Though SONARA is run like a private corporation, the fact that the state is the majority shareholder means the World Bank has an eye on what the state does, as well as on what the corporation does, said Mr. Metouck.

SONARA seeks financing like a private company, presenting an economically viable project to the financial markets. Political will in the region is important when borrowing is done in the financial market rather than from the state, he said.

"We ask lenders to look at our project. If it is economically viable, they will finance it," said Dr. Yenwo.

As a shareholder, the state contributes ideas for consideration, said Mr. Metouck. "But since it is not the state that is loaning us money, we need not ask them for permission for a project. We depend on the quality of the project, its products and our internal financial situation."

The state's presence as a shareholder means that the World Bank and the IMF are obliged to oversee the project so that state involvement does not exceed guidelines.

Top priority

Above all, the goal of Cameroon's downstream strategy is to be self-sufficient in refined products. Before the country's refinery was built, a refinery in Gabon supplied Cameroon's market. When Gabon lost a football match to Cameroon, it stopped supplying Cameroon with refined products.

"A very small problem (such as that) could cost us our oil independence," said Dr. Yenwo. "We have our own crude. And with the insecurity in the region, the best way to be independent is to utilize that crude in the best way possible."

Natural Gas Potential:

Natural gas will generate electricity, provide LPG and feed LNG plant

With significant proven natural gas reserves and a looming demand for clean energy to fuel its economic growth, Cameroon has developed a strategy to develop those reserves for power generation, domestic use and export revenue.

The opportunities are large. Only small gas volumes are now produced, and are used primarily to enhance oil field performance and generate in-field electricity.

The country's natural gas resources are large, but a more accurate assessment of those reserves must await additional exploration and appraisal. According to *Oil & Gas Journal*, Cameroon has 3.9 trillion cubic feet (tcf) of proven natural gas reserves, the bulk of which is located in the Rio del Rey, Douala and Kribi-Campo basins. An estimate by Cameroon's Société Nationale des Hydrocarbures (SNH) estimate is higher, at about 5.5 tcf.

In addition to using natural gas to expand power generation capacity and LPG production, several studies in recent years focused on ways to monetize and add value to the excess gas production, including gas-to-liquid (GTL) and liquefied natural gas (LNG) schemes. Syntroleum Corp. studied the feasibility of a GTL plant at Sanaga in 2005, for example. And building an LNG complex in Cameroon has been under consideration for several years.

The challenge with both these options is the relatively modest gas volumes available for a plant—at least initially. Both LNG and GTL operations need a guarantee of large gas volumes over long periods to be economically viable.

With this in mind, instead of its own facility, Cameroon will cooperate with neighboring Equatorial Guinea, where a large LNG plant already in place can draw on gas supplies from several countries in the region.

In Cameroon, the first significant use of natural gas will be for a badly needed increase in electricity generation capacity. Gas available under a 25-year contract signed by Perenco Cameroon S.A. with SNH in 2006 to develop the offshore Sanaga Sud gas fields in the Douala/Kribi-Campo basins will be used to generate power at a plant at Kribi. Both Perenco and SNH will invest $50 million in the project. According to the U.S. Energy Information Administration, Sanaga Sud could contain 600 billion cu ft (bcf) of gas.

Workers oversee security of electric grid.

Electricity plant, Logbaba.

Generators room plant.

Operator Perenco's conceptual studies for the development of the Sanaga Sud gas field are complete and gas is expected to be available in the first quarter of 2009.

Cameroon has also signed an initial agreement with Equatorial Guinea to supply natural gas to Equatorial Guinea's LNG complex. The agreement is based on studies that concluded Cameroon had sufficient gas reserves to supply 200 million cu ft/day (MMcfd) to the plant for 20 years beginning in 2010-2011. Those studies also helped define the infrastructure required for gathering, processing and transporting the gas, including conditions for building a pipeline between the two countries.

Cameroon's gas development strategy also calls for an increase in production of LPG, widely used as domestic fuel in Cameroon. There are two main plans for LPG production, said Minister of Energy and Water Sindeau Jean Bernard. One is a plant in the Limbé region that would be a private development. The other, in the southern region around Kribi, would be related to the gas delivered to Equatorial Guinea for conversion to LNG.

To enable SNH to execute its ambitious gas projects successfully, the Board of Directors in mid 2007 created a Gas Directorate within the corporation to implement the master plan for Cameroon's natural gas development.

This was one of the resolutions of the board of directors' meeting held in June last year under the chairmanship of Laurent Esso, Minister of State, Secretary General of the Republic and Chairman of the SNH board.

Corporate activities during the first part of 2007 were reviewed at the meeting,

Cameroon has developed a strategy to develop proven natural gas reserves for power generation, domestic use and export revenue.

including an appraisal well drilled successfully by operator Euroil on the Etinde permit. Production tests gave a substantial gas output, as well as 3,800 b/d of condensate.

Kribi plant

In a summary of proposed investment dated February 20, 2008 the International Finance Corp. (IFC), a member of the World Bank Group, said it proposes to invest up to $85 million (up to 25% of total project cost) in Kribi Power Development Corp. (KPDC) for the development of two thermal power plants in Cameroon.

IFC provides loans, equity, structured finance and risk management products, and advisory services to build the private sector in developing countries. KPDC is an affiliate of AES SONEL, the privatized integrated electric utility of Cameroon. KPDC's majority shareholders will be AES Corp. (AES) and the Government of Cameroon. AES SONEL will also be the off-taker of the power produced by KPDC.

AES has over 44,000 mw of installed capacity in 26 countries. AES SONEL was privatized in 2001 when AES purchased 56% of its shares. The company, with an installed capacity of 933 mw and a customer base of 525,000, operates under a 20-year concession agreement with the government of Cameroon.

IFC notes in the proposal that the Summary of Proposed Investment is distributed to the public in advance of the IFC Board of Directors' consideration of the proposed transaction in order to enhance the transparency of IFC's activities. The document does not presume the outcome of the Board decision, which was expected to be made at a meeting on May 20.

The expected project cost of about $335 million is to be financed on a debt-to-equity ratio of 75:25. IFC's proposed investment is a loan of up to $85 million (no more than 25% of total project cost). Other participating lenders are expected to include European Investment Bank (EIB), the African Development Bank (ADB), the Central African States' Development Bank (BDEAC), France's Investment and Promotions Company for Economic Cooperation (Proparco), Emerging Africa Infrastructure Fund (EAIF) and Netherlands Development Finance Co. (FMO).

Two thermal power plants will be Cameroon's first Independent Power Project (IPP), said the report. One is the Dibamba 86-mw heavy fuel oil (HFO)-fired diesel engine power plant and associated 2 km, 90,000 volt transmission line in the Douala region (Dibamba). The other is the Kribi gas-fired plant with a capacity of 150 mw and an associated 100-km 225,000-volt dual transmission line from Kribi to Edéa (Kribi), fueled by gas from the Sanaga Sud project.

"We like competition and I think we are ready to face it. All we need is healthy competition. Competition is another source of motivation."
Jean David Bilé, AES SONEL General Manager

The Sanaga Sud gas facility is not part of the IFC funding, but it is expected to be the main supplier of the Kribi plant.

The power plants will help meet Cameroon's growing demand for electricity, and diversify its supply, which currently is primarily from hydroelectric sources. It will replace inefficient thermal power plants, reducing carbon emissions, said IFC.

The Dibamba plant will be located about 15 km from Douala and will be

View of outdoor high-voltage switching station at the 85-MW plant at Limbé.

connected to the Southern Interconnected Grid (SIG) at the existing Ngodi Bakoko substation; the site is near the country's largest load center and port facilities. The Kribi plant site is 9 km northeast of the coastal city of Kribi, close to the Sanaga Sud gas field. The new transmission line will run between Kribi and the existing Mangombe 225,000/90,000 volt substation at Edéa in the Littoral Province.

According to the IFC report, the project is part of the least cost expansion plan for the power sector developed during an economic study commissioned by AES Some. Project objectives include:

- provide emergency oil-based generation through Dibamba to reduce power shortages in 2008/2009;
- meet growing incremental demand for electricity in the country;
- increase fuel diversity in a hydroelectric-dominated electricity sector and improve long term energy supply security during the dry season or in years with low rainfall;
- support the development of Cameroon's gas resources; and
- generate tax and dividend revenues for the government.

AES SONEL role

In collaboration with the state, AES SONEL has drawn up an ambitious strategy aimed at meeting Cameroon's electricity demand in both the short and long terms. Implementation of that strategy, which depends heavily on natural gas, is in its very early stages.

"Before privatization, we had fallen far behind in terms of investment and maintenance," said Jean David Bilé, CEO, AES SONEL. "Equipment was in an advanced state of deterioration."

To remedy the situation, the government and AES Corp., agreed to a cooperation strategy that took the form of a concession agreement. After the first five years of the concession, the two parties reviewed the agreement, and amended it to include a number of service quality obligations with which AES must comply, said Mr. Bilé.

These obligations include an investment plan amounting to about US$1.2 billion over a period of five years. "It is an ambitious program, but we have the backing of international financial institutions and are continuing to work in close collaboration with the state," said Mr. Bilé.

The program involves rehabilitation of existing generation facilities, including the company's main dam at Edea, which is more than 50 years old, and the Songloulou dam, commissioned in 1981.

AES SONEL electricity plant, Logbaba.

One of the major initial investments increased thermal capacity by 47 mw. Then in 2004, AES SONEL built an 85-mw heavy fuel oil power plant in Limbé as an emergency response to the energy shortage the country was facing.

One reason for the development of alternative sources, especially thermal, was to address the vagaries of the weather which result in irregular water flows that can range from 6,000 cu m/second in the rainy season to 15 cu m/second in the dry season. Diversity of sources frees the country from these weather hazards, and it helps optimize the management of water resources.

The two thermal plants—Dibamba and Kribi—will help diversify electricity supply when they come on stream in 2008 and 2009, respectively.

In addition to these investments, AES SONEL has invested more than US$250 million on distribution facilities, mainly to reinforce and extend the system.

"There is, however, a lot left be done," said Mr. Bilé. Even though AES-SONEL is the only operator in charge of generating, transmitting and distributing electricity in Cameroon, it is prepared to compete with others in the sector, he said.

"We like competition and I think we are ready to face it. There's talk about the imminent opening up of the sector to other operators, and they will be welcome. All we need is healthy competition. Competition is another source of motivation. What we need is clearly defined rules that are applied without discrimination to other operators."

Even though AES SONEL expects to be the main operator for a long time to come, there is room for other operators in power generation. For example, the country's aluminium production factory, AluCam, has plans to double its capacity. Though the factory plans to invest in the construction of a hydroelectric dam, a good part of the energy it will need to meet its objective will come from AES SONEL.

Current regulations allow new operators to use AES SONEL's transmission system with the payment of a fee.

Growing markets

Recent data show that the industrial sector consumed about half of the electricity generated by AES SONEL, but contributed only 8% of the company's revenue; residential customers used 28% of the power and provided 51% of revenue.

"Our revenue grows faster than generation capacity because we suffer a high rate of technical losses," said Mr. Bilé. "As we resolve that problem, our revenue continues to grow rapidly without there being any major changes in tariffs or generating output."

Currently there is rapid growth in the number of residential customers as a result of the company's commitment to the government to execute an average of 50,000 new connections per year over the 20 years of the concession. For 2007, the objective was to make 48,000 new connections, according to Mr. Bilé.

> "The country has abundance of gas and water resources. When demand is there electricity can be made available quickly."
>
> Jean David Bilé, AES SONEL General Manager

Demand grows significantly as new households are connected. Currently, industrial demand is growing more slowly. "We have a little over 1,300 industrial customers and their demand does not increase that much."

The industrial sector is heavily dependent on the government's strategy. The country has an abundance of gas and water resources. When demand is there electricity can be made available quickly, he said.

The company has several strategies to attract other potential partners. Because AES SONEL plays a key role throughout Central Africa, it envisions an interconnection with the networks of other countries, namely, Chad, Gabon, the Central African Republic, Congo and perhaps Nigeria.

"I think when this interconnection is made, we will need to conclude partnerships with the various companies in order to be able to construct plants and export energy to neighboring countries," said Mr. Bilé.

"It will also offer Cameroon the opportunity to have affordable energy."

Studies on establishing such an electricity market were conducted with the support of the US Agency for International Development (USAID). The project was discussed by leaders of the various electric utilities in July and then presented to the Heads of States of Central Africa in December.

The LNG strategy

Cameroon's agreement with Equatorial Guinea to convert a portion of Cameroon's natural gas production to LNG at the EG complex makes good strategic and economic sense.

There was some thought given to building an LNG complex in Cameroon to avoid being dependent on the Equatorial Guinea facility, said Mr. Ruud Schrama, until recently President and General Manager of Pecten Cameroon.

"But there are some technical, water depth, and commercial constraints," he said. "The volumes expected to be available for LNG—about 200 or 300 MMcfd over a period of 20-25 years—is not enough to justify a stand-alone full-size LNG scheme."

Investors would likely find that this modest expected production rate would pose too great a risk.

Cameroon's business model is also different from that of the Equatorial Guinea LNG operation. In Equatorial Guinea, one large integrated project delivers gas from a field to the LNG complex. In Cameroon, there are multiple individual parties, making it necessary for any LNG plant to be a business in itself, said Mr. Schrama.

Though in Europe in recent years, a business model involving smaller fields rather than one large field has emerged, he said, to make the exploitation of smaller discoveries attractive to operators and investors requires an adequate infrastructure that is available to all parties.

Achieving National Promise:

Opportunity, stability, valuable human "resource" will drive growth

With a foundation of significant oil and gas resources and a history of attracting international partners, Cameroon's future is enhanced by the strategies it has created to optimize the value of its petroleum assets.

Foreign firms are welcome in Cameroon, said Prime Minister Ephraim Inoni recently, and the country is attracting significant investment. "People like to invest here because our policy is liberal and opportunities exist."

Industrial development and growing energy demand will bring ambitious projects that require assistance from those investors, according to Sindeu Jean Bernard, Minister of Energy and Water.

"We have seen new initiatives in the past year that will improve our infrastructure; that should help attract international companies," said Jacky Lesage, General Manager, Cameroon Oil Transportation Co. (COTCO).

COTCO has refurbished about 100 classrooms along the pipeline route.

The human element

Nor should the human "resource" be overlooked. After only four years of operation, Cameroon citizens make up more than 80% of COTCO's work force, according to Mr. Lesage. At the end of 2007, more than 50% of supervisory and management positions were occupied by Cameroon nationals.

In the refining sector, SONARA has met the challenge of national content, said Mr. Charles Metouck, General Manager. "We have substantial human resources, including people educated in the US and in Europe, as well as people that have been well educated locally."

Though AES SONEL's main mission is to supply electricity, its role also goes beyond that sector, said Jean David Bilé, CEO. "We are developing the skills of our staff both within the country and abroad. In Cameroon, for example, we introduced a training program from the Darden Business School in the US to improve the management and leadership capabilities of 200 of our staff."

Electricity's role

Electricity demand, about 600-700 mw in 2007, was expected to reach about 1,000 mw this year, said Prime Minister Inoni. "In five years, we might need 1,500 mw."

In addition to the gas-powered generating plant at Kribi, the government is considering building hydroelectric dams at Lom Pangar, Nachtigal and Memve'ele.

"Supplying the economy with energy contributes to the development of the economy," said Mr. Bilé, "but we need to strike a balance." For example, if the electricity sector grows too quickly, customers must bear the cost of unused generating capacity. And in rural areas, economic development does not always follow the availability of electricity, he said.

AES SONEL's emphasis is on increasing the number of domestic customers and improving the quality and dependability of service. The company recently received financing for a 240 million mid-term investment program.

Other challenges

If there is a challenge common to many segments of Cameroon's economy, it is infrastructure-highways, airports, pipelines and petroleum storage. Infrastructure improvement is critical to economic growth and is the focus of a range of initiatives. Reducing the cost of petroleum products in Cameroon is an important goal, said Mr. Ibrahim Talba Malla, Director General, Caisse de Stabilisation Prix des Hydrocarbures (CSPH).

Reducing taxes and import duties would help. For example, the rate of the fuel tax that is transferred to the Road Fund can be decreased and replaced with more funding from the cost of distribution.

Even though the dispute with Nigeria has been resolved, there are still challenges to the stability of the region.

"There are no real boundaries in the north," said Prime Minister Inoni. The terrain is such that even without roads, people can drive through the border. And in the south, Calabar port of Nigeria is always silted. For vessels to get into Calabar, they have to use the eastern part of the estuary, which is on the Cameroonian side.

In the long term, Cameroon's relationship with the US will be important for both parties, said Niels Marquardt, until recently the US Ambassador to Cameroon.

Areas to be emphasized include an effort on the part of both governments to facilitate the exchange of travelers. One way to do that is to reciprocally eliminate visa fees. Another important area is security and peacekeeping.

"Resolution of the Bakassi crisis with Nigeria, I think, paves the way for Cameroon to play a stronger role in regional peacekeeping," said Ambassador Marquardt.

CAMEROON GENERAL DATA

- *Official Name:* Republic of Cameroon
- *Capital:* Yaounde
- *System of Government:* Unitary Multiparty Republic
- *President:* Paul Biya (since 6.11.1992)
- *Prime Minister:* Ephraim Inoni (since 8.12.2004)
- *Languages:* 24 major African language groups, English (official), French (official).
- *Location & Geography:* Cameroon is located in Central West Africa. It is bound by Equatorial Guinea, Gabon, Congo, the Central African Republic, Chad, Nigeria and the Gulf of Guinea to the west.
- *Climate:* varies with terrain, from tropical along coast to semiarid and hot in the north.
- *Land Area:* 457,439 Sq Km (183,568 Sq Mi)
- *Population:* 18,060,382 (July 2007 est.)
- *Currency:* Communaute Financiere Africaine franc (XAF)
- *GDP/PPP (2007 est.):* $20.93 billion; per capita $2,300
- *Real Growth Rate:* 3.2% (2007 est.)
- *Industries:* petroleum production and refining, aluminum production, food processing, light consumer goods, textiles, lumber, ship repair.
- *Natural Resources:* Bauxite, Cassava, Cocoa, Coffee, Cotton, Ground Nuts, Gold, Iron Ore, Livestock, Maize, Millet, Oil and Natural Gas, Palm Oil, Plantains, Rubber, Sorghum, Sweet Potatoes, Timber, Tin, Yams.
- *Exports:* $3.705 billion f.o.b. (2007 est.) crude oil and petroleum products, lumber, cocoa beans, aluminum, coffee, cotton.
- *Imports:* $3.632 billion f.o.b. (2007 est.) machinery, electrical equipment, transport equipment, fuel, food.
- *Major Trading Partners:* France, the USA, Germany, Japan, Italy, the Netherlands and Russia.

Source: Altapedia, Governments on the WWW, Columbia Encyclopedia

ENERGY OVERVIEW

Proven Oil Reserves:
400 million bbl (1 January 2006 est.)
Oil Production:
82,670 bbl/day (2005 est.)
Oil Consumption:
24,200 bbl/day (2005 est.)
Net Oil Exports:
107,400 bbl/day (2004)
Crude Refining Capacity:
42,000 bbl/d.
Natural Gas Reserves:
105.9 billion cu m (1 January 2006 est.)

Source: EIA - Country Analysis briefs on Cameroon

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- Caisse de Stabilisation des Prix des Hydrocarbures (CSPH) – General Director Ibrahim Talba Malla
- SONARA National Refining Company – General Manager Mr. Charles Metouck
- Noble Energy Cameroon – Country Manager Mr. Don Nelson
- Pecten Cameroon and Shell – Mr. Ruud Schrama (previuos Country Manager in Cameroon) and Vincent Holtam (Current President and Country Manager of Cameroon operations)


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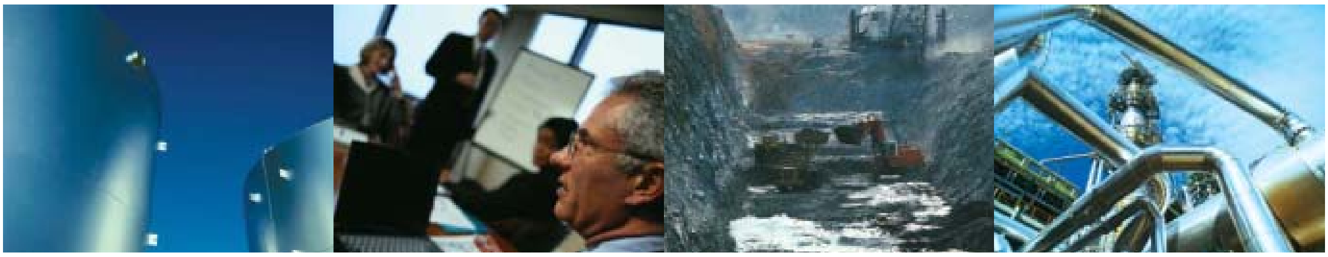

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SELECTION, NOTIFICATION & RESPONSIBILITIES

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

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

Notification: All primary contacts will be notified in writing no later than **January 2009** as to whether or not their proposed Oil Sands and Heavy Oil Technologies abstract has been selected.

Primary Contact Responsibilities: The primary contact will be responsible for meeting all deadlines and requirements regarding the paper presentation or panel participation. The primary contact must sign a Materials Release Form by **February 2009** and agree to submit a final manuscript to be included in the conference proceedings by **May 2009.** This contact also needs to notify conference management of any changes, additions or corrections in author, co-author or panelist names, paper titles or availability to present the submitted paper at the appointed date and time. Unless otherwise noted on the abstract, the presenter will be considered the primary contact.

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

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