Week of Oct. 12, 2009/US$10.00

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com

Refinery Sulfur Issues

Drawdown uncertainty among issues for SPR
BC's silent majority key to Queen Charlotte basin oil
High-volume ESPs restore oil production in Suriname
Study places CO_2 capture cost at $34-61/ton

OIL&GAS JOURNAL

Oct. 12, 2009
Volume 107.38

Refinery Sulfur Issues

Image from CB&I's Virtual Refinery

Regular Features

Cover

In 2003, Valero Energy Corp. installed this 50,000-b/d gasoline hydrotreater, designed and built by CB&I, Houston, at its Port Arthur, Tex., refinery to produce low-sulfur gasoline, as required by US Environmental Protection Agency's Tier II regulations. The most recent expansions of the crude and vacuum units have increased the refinery's ability to process lower-cost, heavy sour crude oil and increased total throughput capacity to 310,000 b/d. For more on current refinery-sulfur issues and operations, see Oil & Gas Journal's exclusive special report that begins on p. 44. Photo from CB&I.

OIL&GAS JOURNAL *online*

The full text of Oil & Gas Journal is available through OGJ Online, Oil & Gas Journal's internet-based energy information service, at http://www.ogjonline.com. For information, send an e-mail message to webmaster@ogjonline.com.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 47 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. \$89; Latin America and Canada: 1 yr. \$94; Russia and republics of the former USSR, 1 yr. 2,200 rubles; all other countries: 1 yr. \$129, 1 yr. premium digital \$59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are \$10 each except for 100th Anniversary issue which is \$20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 107, No. 38) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

PennWell, Houston office

1455 West Loop South, Suite 400, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com

Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor/News Writer Leena Koottungal, lkoottungal@ogjonline.com

Vice-President/Group Publishing Director Paul Westervelt, pwestervelt@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office

1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290

Presentation/Equipment Editor Jim Stilwell, jims@pennwell.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

London

Tel +44 (0)20.8884.4246
International Editor Uchenna Izundu, uchennai@pennwell.com

Washington

Tel 703.533.1552
Washington Editor Nick Snow, nicks@pennwell.com

Los Angeles

Tel 310.595.5657
Oil Diplomacy Editor Eric Watkins, hippalus@yahoo.com

OGJ News

Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service

P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Audience Development Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters

1421 S. Sheridan Rd., Tulsa, OK 74112

P.C. Lauinger, 1900-1988
Chairman Frank T. Lauinger
President/Chief Executive Officer Robert F. Biolchini

Member Audit Bureau of Circulations & American Business Media

OGJ Newsletter

Oct. 12, 2009

International news for oil and gas professionals
For up-to-the-minute news, visit www.ogjonline.com

General Interest — *Quick Takes*

Shell settles EPA chemical reporting allegation

Shell Guam Inc. agreed to pay $30,590 to settle charges that it violated a federal environmental law by not submitting required toxic chemical reports, the US Environmental Protection Agency said on Oct. 5.

The Royal Dutch Shell PLC subsidiary agreed to pay a $7,950 fine as part of the settlement, and to donate $28,300 to the US territory's fire department for personal protective equipment, EPA said.

EPA said Shell Guam regularly uses polycylic aromatic compounds, naphthalene, and other toxic chemicals as components of fuel that it repackages at its facility. The company allegedly failed to submit toxic release inventory reports to EPA of the amounts of chemicals it processed in 2007, as required under the Emergency Planning and Community Right-to-Know Act.

Facilities that process more than 25,000 lb/year of the chemicals cited in this case must report releases of these chemicals annually to EPA and the state or territory in which the plant is located, the federal environmental regulator said.

EPA said it compiles toxic chemical information annually from the previous year to produce a publicly available toxics release inventory. It said this database estimates the amounts of each toxic chemical released into the environment; treated or recycled onsite; or transferred off-site for waste management, and also provides a trend analysis of toxic chemical releases.

EPA cites Frontier for impoundment violations

Frontier Refining Inc. illegally stored hazardous waste in a wastewater management pond at its Cheyenne, Wyo., facility, the US Environmental Protection Agency charged.

The waste was stored in a pond that was neither constructed nor operated properly to prevent and detect leaks, EPA said in an enforcement and compliance action that it filed on Oct. 1.

EPA said other violations of the federal Resource and Conservation Recovery Act that it found during a March inspection related to closing the pond and providing financial assurance for its proper closure.

EPA sought nearly $7 million in fines from Frontier for operating an unauthorized hazardous waste unit.

The order also requires the refiner to take the pond out of service, remove wastewater and sludge, determine whether the wastes leak into groundwater or soils, remove the existing pond structure and contaminated soils, and cap the area in accordance with RCRA requirements for closing a surface impoundment, EPA said.

Gazprom enters US gas trading, marketing market

Gazprom Marketing & Trading USA Inc. has begun trading and marketing of natural gas, marking the US entry by a unit of Russia's OAO Gazprom.

"We look forward to significant growth and profitability from our expanding geographical base," said Vitaly Vasiliev, chief executive officer of the UK's Gazprom Marketing & Trading Ltd.

Gazprom's US trading and marketing unit has acquired more than 350 MMcfd of physical gas supplies at several sites across the US for the next 3-7 years through long-term gas swaps.

The company also will market LNG exported to North America. This includes long-term agreements enabling it to buy LNG from the Sakhalin-2 LNG plant and regasify the LNG in Baja California, Mexico, to be transported by pipeline for sale in the southwestern US.

The company also plans to import LNG into the US from the giant Shtokman LNG development in the Arctic. ✦

Exploration & Development — *Quick Takes*

BP reports Tebe oil discovery off Angola

A BP PLC subsidiary said test results show its Tebe oil discovery on ultradeepwater Block 31 off Angola has the reservoir capacity to flow more than 5,000 b/d "under production conditions."

The well was drilled in 1,752 m of water to 3,325 m TD in the southern portion of the block about 12 km southeast of the October 2005 Hebe discovery and 350 km northwest of Luanda, Angola's capital and largest city.

Company officials said Oct. 1 it is BP's 19th discovery on Block 31. BP Exploration (Angola) Ltd. is operator with 26.67% interest. Sonangol is concessionaire of Block 31, with Sonangol P&P holding 20%.

Other interest owners are Esso Exploration & Production Angola (Block 31) Ltd. 25%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and Total SA unit Tepa (Block 31) Ltd. 5%.

Consortium officials said development of their deepwater Pluto, Saturn, Venus, and Mars oil fields in the northeast sector of Block 31 is proceeding with first production targeted in 2012.

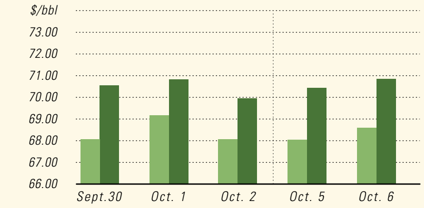
Maari field partners confirm additional reserves

The OMV-led joint venture at Maari oil field in the Taranaki basin off New Zealand has confirmed additional produceable oil reserves are contained within a separate reservoir, designated M2A, about 50 m above the main Moki formation.

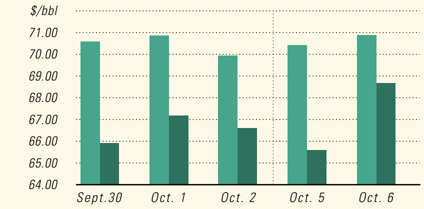
It lies in the main Maari mining licence PMP 38160.

Industry Scoreboard

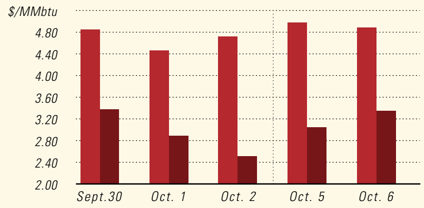
IPE BRENT / NYMEX LIGHT SWEET CRUDE



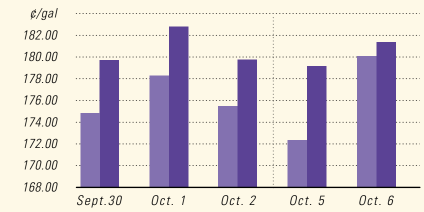
WTI CUSHING / BRENT SPOT



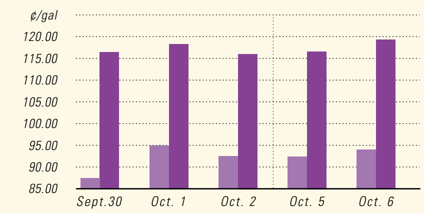
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



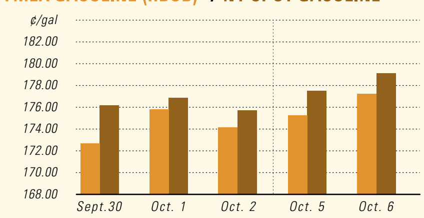
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Nonoxygenated regular unleaded.

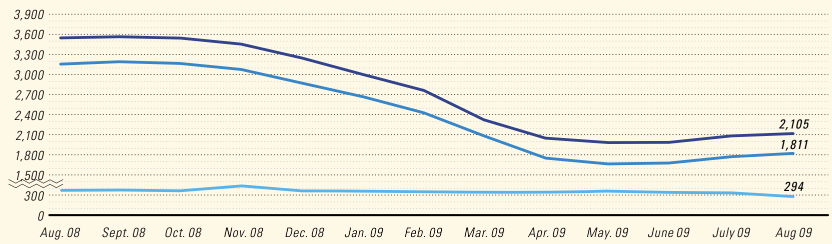
US INDUSTRY SCOREBOARD — 10/12

Latest week 9/25	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	9,138	8,747	4.5	9,002	9,027	–0.3
Distillate	3,409	3,708	–8.1	3,597	3,955	–9.1
Jet fuel	1,451	1,541	–5.8	1,396	1,584	–11.9
Residual	499	517	–3.5	576	626	–8.0
Other products	4,707	3,889	21.0	4,210	4,458	–5.6
TOTAL DEMAND	19,204	18,402	4.4	18,781	19,650	–4.4
Supply, 1,000 b/d						
Crude production	5,279	4,309	22.5	5,227	5,014	4.2
NGL production[2]	2,208	1,992	10.8	2,011	2,132	–5.7
Crude imports	9,342	9,185	1.7	9,269	9,811	–5.5
Product imports	2,429	2,989	–18.7	2,756	3,150	–12.5
Other supply[3]	1,683	1,570	7.2	3,058	1,548	97.5
TOTAL SUPPLY	20,941	20,045	4.5	22,321	21,655	3.1
Refining, 1,000 b/d						
Crude runs to stills	14,509	12,994	11.7	14,509	14,697	–1.3
Input to crude stills	14,867	13,375	11.2	14,867	15,038	–1.1
% utilization	84.2	75.9	—	84.2	85.4	—

Latest week 9/25	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	338,404	335,608	2,796	294,464	43,940	14.9
Motor gasoline	211,452	213,109	–1,657	179,640	31,812	17.7
Distillate	171,077	170,754	323	123,090	47,987	39.0
Jet fuel–kerosine	45,983	46,199	–216	36,050	9,933	27.6
Residual	33,969	32,635	1,334	36,228	–2,259	–6.2
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	22.8	22.4	1.8	23.2	–1.7	
Motor gasoline	23.4	23.3	0.4	20.3	15.3	
Distillate	50.5	50.1	0.8	32.3	56.3	
Propane	72.9	66.6	9.5	72.0	1.3	
Futures prices[5] **10/2**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	68.99	68.43	0.56	107.32	–38.33	–35.7
Natural gas, $/MMbtu	4.53	3.80	0.73	7.69	–3.17	–41.2

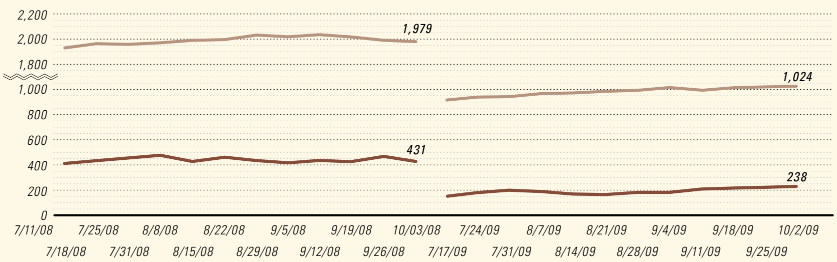
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

The group has now completed a horizontal well into this reservoir that encountered 660 m of net pay zone. OMV estimates the in-situ oil reserves to be 30-40 million bbl, or about a quarter of the volume of the in-situ reserves figure placed on the Moki formation reservoir.

However an estimate of recoverable reserves in the new zone will not be available until production data from the M2A well has been obtained and a development plan established.

The joint venture wants to produce from the M2A well only intermittently when there is available spare capacity in the Maari production facilities.

At the moment, the field's five Moki production wells are producing at close to 40,000 b/d of oil, which is 10% more than the 35,000 b/d design capacity of the Raora floating production, storage, and offloading vessel now stationed in the field.

The field, which is New Zealand's largest oil field, has produced more than 3 million bbl since it came on stream in February.

OMV now plans to return to the Manaia-1 extended reach well, which has targeted and found hydrocarbons within the Mangahewa sandstone in a structure about 10 km southwest of Maari field. This well was suspended in mid-September so the M2A well could be drilled at Maari. The plan is to reenter the well to drill a horizontal section through the reservoir to determine the viability of the find. The Ensco 7 jack up drilling rig is being used for the program.

If Manaia is commercial, the production will be tied back to the Maari facilities.

Manaia-1 is an appraisal of the Mangahewa Sand reservoir found back in 1970 by the Shell-BP-Todd group with the Maui-4 vertical well which tested oil at 575 b/d, but was not commercial at that time. The structure now lies in the greater Maari exploration licence PEP 38413.

OMV is operator of both licences with 69% interest. New Zealand's Todd Energy has 16%, Sydney's Horizon Oil has 10%, and Cue Energy Resources, Melbourne, holds 5%.

Eni gains operatorship of Ghana licenses

Eni Ghana Exploration & Production Ltd. will operate the Offshore Cape Three Points (OCTP) and Offshore Cape Three Points South (OCTPS) exploration licenses in Ghana after acquiring a major interest from Vitol Upstream Ghana Ltd.

Eni will hold a 47.22% interest in both blocks while Vitol will take a 37.78% interest. State company Ghana National Petroleum Corp., meanwhile, will hold 15%. GNPC will have a back-in option for an additional 5% in OCTP and 10% in OCTPS.

The consortium this summer drilled the Sankofa-1 well on the OCTP block in 850 m of water. "The well encountered high-quality reservoir sands containing 36 m (net) of oil and gas. Both blocks lie in the prolific Tano-Cape Three Points oil basin, which has recently yielded some of the biggest offshore discoveries yet made in Africa," said Eni. The Sankofa is a significant hydrocarbon discovery that is 35 km east of Jubilee field, which will start production next year.

This deal marks the reentry of Eni in Ghana where it was present until the 1970s.

Eni has been present in Sub-Saharan Africa since the early 1960s. Its operated production in the area is 450,000 boe/d.

Southwestern Campos basin well finds oil

An exploratory well in the southwestern Campos basin has cut an oil column of more than 100 m with about 40 m of highly porous and permeable sandy reservoirs, said OGX Petroleo e Gas Participacoes SA, Rio de Janeiro.

The 1-OGX-1-RJS well, in 140 m of water 85 km off Rio de Janeiro in the BM-C-43 block, is still drilling toward deeper objectives using the Diamond Offshore Ocean Ambassador semisubmersible. OGX, which gave no depths or other details, holds 100% interest in the block.

The block is southwest of Maromba oil field, which Petroleo Brasileiro SA declared commercial in late 2006. ✦

Drilling & Production — *Quick Takes*

Apache to tap Argentina unconventional gas

Argentina's secretary of energy has approved the first contract under an incentive program to encourage development of unconventional natural gas reservoirs.

Under the contract, Apache Corp., Houston, will drill as many as 48 wells in two Neuquen basin fields in the next 4 years and supply 50 MMcfd of gas at a price of $5/MMbtu. The contracts take effect in January 2011, but the power plant customer has indicated it may begin taking gas in mid-2010.

The expected reserves would not be developed without Argentina's Gas Plus program, said Jon Graham, president of Apache Argentina. Apache has submitted five more development projects in the same basin with different geological parameters for approval under Gas Plus.

At Anticlinal Campamento field in Neuquen Province, Apache will drill as many as 12 wells to tap dry gas in Jurassic Pre-Cuyo fractured volcanics and basement reservoirs as deep as 10,500 ft. Apache describes the reservoirs as unconventional and said it will apply multiple hydraulic fracs in the highly deviated lower part of the wells.

Meanwhile, Apache will drill as many as 36 wells in Estacion Fernandez Oro field in Rio Negro Province. These wells involve drilling to 12,500 ft true vertical depth with as much as 20° of deviation and conducting multiple fracs in tight Jurassic Lower Lajas sandstone. Expected recovery is rich gas and 50° gravity condensate.

Apache will provide measurement and production facilities for the Gas Plus volumes separate from the rest of the fields' production facilities.

Apache produced 193 MMcfd of gas in Argentina at an average $1.89/Mcf in the quarter ended June 30. That included sales to regulated residential and power generation markets and deregulated industrial markets.

Regulators recently approved price increases in the residential and power generation sectors, Apache said.

Oyong gas field off Indonesia comes on stream

Santos Group's Oyong natural gas field off Indonesia has been brought on stream as part of the field's Phase 2 development.

Gas is being transported from the field via a 60-km subsea pipeline to an onshore processing plant at Grati in East Java.

Oyong lies in the Sampang production-sharing contract area in the Straits of Madura and contains both oil and gas reserves in the Mundu formation carbonate reservoir of Pliocene age.

Discovery well Oyong-1 was drilled in 2001 and Phase 1 oil development began in September 2007.

Phase 2 has been to recover the field's estimated 103 bcf of gas reserves. Gas is contracted to PT Indonesia Power to use as an electric power generation fuel under a deal signed in 2003.

Santos Ltd., Adelaide, is operator with 40%. Cue Energy Ltd., Melbourne, has 15% and Singapore Sampan has 40%.

Apache, Santos let Reindeer field contract

Apache Energy Corp. and Santos Ltd.—partners in the Reindeer field-Devil Creek natural gas project in Western Australia—have let a $195 million (Aus.) contract to a joint venture of Malaysia's Sapura Crest Petroleum and Norway's Acergy for the installation of a suite of pipelines and offshore production facilities.

The work involves the transport and installation of 91 km of rigid pipeline including offshore pipeline and a shallow-water beach approach, subsea tie-in and stabilization works, as well as a wellhead platform at the Reindeer gas field comprised of a 1,700-tonne four-leg steel jacket and a 450 tonne topside processing module.

Engineering and preparatory work will begin immediately in Kuala Lumpur and Perth. Offshore installation is scheduled to begin late next year using the Sapura 3000 dynamic positioning heavy lift and pipelay vessel.

The Devil Creek gas plant is about 50 km south of Karratha and will supply as much as 220 TJ/day of sales gas into the Dampier-Bunbury trunkline. There will also be an associated production of up to 500 b/d of condensate stripped from the gas stream.

Work at Devil Creek began in September and the plant is scheduled to come on stream at the end of 2011.

SPE: Oil recovery takes collaboration

Recovering the world's remaining oil resources will require a collaborative effort of national oil companies, international oil companies, and service companies, according to Mohammed Al-Qahtani, executive director, petroleum engineering and development of Saudi Aramco.

Al-Qahtani made his comments Oct. 5 at the SPE Annual Conference & Exhibition in New Orleans.

Al-Qahtani said the world still had considerable amounts of oil to recover. His estimate was that about 4.7 trillion bbl remained to be produced. This includes about 2 trillion bbl from reserves additions and exploration, 1.5 trillion bbl from nonconventional resources, and 1.2 trillion from new technology, he said.

In addition, he noted that the world would need an additional 90 million b/d to offset declines in existing oil fields to reach a 125 million b/d level by 2030. Current world production is about 80 million b/d.

SPE: Chemistry scoring index proposed

A chemistry scoring index may help address the recent controversy on assessing the hazards of chemicals used in stimulating wells, according to Ron Hyden, strategic business manager for Halliburton's production enhancement product service line in Houston.

Hyden made his remarks Oct. 5 at the SPE Annual Conference & Exhibition in New Orleans.

He said Halliburton has developed an index that currently a third party is assessing. Upon finalizing the index, Halliburton plans to release it for use in the industry, Hyden said.

The index addresses the ability of chemicals to be health, physical, and environment hazards.

Concerns related to heath include chemical toxicity and whether the chemicals are carcinogens and mutagens as well as if they affect reproduction and organs. Another health concern is whether the chemicals are corrosive or irritant substances.

Physical hazards relate to chemical properties such as explosiveness, flammability, oxidization, and corrosiveness.

Environment hazards include whether the chemicals produce acute-chronic aquatic toxicity, hazardous air pollution, and water pollution, as well as if the chemicals bioaccumulate, biodegrade, and are sustainable.

The index expresses the constituent concentration and health, safety, and environmental effect as a numerical aggregated score, Hyden said. He noted that the aggregated score allows companies to select chemical formulations that have the lowest score for their application.

SPE: Pemex aspires for 60% Cantarell recovery

Pemex Exporation & Production is studying new ways for recovering more oil from the tight reservoir matrix of Cantarell field off Mexico.

Speaking Oct. 7 at the SPE Annual Conference & Exhibition in New Orleans, Carlos Morales Gil, Pemex E&P director general, said carbon dioxide injection might provide the means to produce additional oil from the field that originally contained about 35 billion bbl of oil in place, making it the third largest oil field in the world. Steam injection is another possibility for improving recovery of the field's 22° gravity oil, he said.

Gil said Pemex now targets a 60% oil recovery from the field. To date, Pemex has produced about 12.2 billion bbl and has obtained a 41% recovery for the Akal portion of the field, he noted.

The Chac 1 well, drilled from June 1974 to July 1976, discovered the field. First production started in 1979 and Pemex maintained about a 1 million bo/d production level until 1996. An infill drilling program, additional platforms, and a 1.2 bcfd nitrogen injection scheme increased production in the field to more than 2 million bo/d in 2001. Since then, production has declined and currently is about 600,000 bo/d, Gil said.

One obstacle for carbon dioxide injection is to find a large source of carbon dioxide. Gil said that the field would need a carbon dioxide supply of about 1.2 bcfd, the same as the nitrogen injection rate. ✦

Processing — Quick Takes

Sunoco idles Eagle Point refinery in New Jersey

Another US independent refiner is slashing operations in response to low refining margins.

Sunoco Inc., Philadelphia, is idling its 150,000-b/d Eagle Point refinery at Westville, NJ, citing "a recessionary economy, weak demand for refined products, and increased global refining capacity."

The refinery is interconnected with Sunoco's refineries at Philadelphia and Marcus Hook, Pa., which form a complex with crude capacity totaling 655,000 b/d.

Sunoco said Eagle Point is the least integrated of the three refineries. The closure will enable the company to increase capacity utilization at the other two facilities and to keep total output by the complex essentially unchanged.

Another independent refiner that has made deep cuts in its operations is Valero Energy Corp., which has shut major units at its Delaware City, Del., and Corpus Christi, Tex., refineries and shut down its refinery in Aruba (OGJ, Sept. 14, 2009, Newsletter).

Sunoco said it will keep the Eagle Point refinery closed until market conditions improve or until it implements other options, which might include using the facility to produce alternative fuels.

In June the company bought a 100 million gal/year ethanol plant at Volney, NY, from bankrupt Northeast Biofuels LP for $8.5 million (OGJ Online, June 18, 2009).

At Eagle Point it will furlough about 400 employees, who will have the option of returning to work if the refinery resumes operation. It will offer the workers a voluntary severance package.

Product storage and handling work will continue at the site, and the Sunoco Logistics Partners LP products rack will remain open.

Sunoco's 170,000-b/d Toledo, Ohio, refinery is unaffected by the move.

Sunoco estimated that idling the Eagle Point refinery will reduce pretax expenses by $250 million/year. It expects to incur pretax charges of $475-550 million, mostly noncash, from asset impairment and idling costs.

The company already had in place an effort to cut costs by $300 million/year by the end of 2009. In its announcement of the Eagle Point closure, it said it would cut its dividend in half to save about $70 million/year.

Murphy Oil acquires ethanol plant

A subsidiary of Murphy Oil Corp. has purchased a corn-based ethanol plant in Hankinson, ND, for $92 million.

Additionally, an estimated $15 million in working capital will be invested into the facility, Murphy Oil said. The plant's production capacity was 110 million gal/year before it was idled in October 2008.

David M. Wood, Murphy Oil president and chief executive officer, said the acquisition will supplement Murphy Oil's growing fuels business.

"It also marks our initial entry into the manufacture of biofuels," Wood said. He cited current ethanol mandates and the company's subsequent blending needs as the reason for Murphy to want "a presence in the supply chain."

Wood said he expects to see ethanol production "shortly," noting that the plant is near a feedstock supply and has accessible rail service for carrying the finished product. ✦

Transportation — Quick Takes

LNG project weathers Indonesian earthquake

Operator BP PLC said that its Tangguh LNG project, which lies in the Bintuni Bay area, is operating normally despite a 6.1-magnitude earthquake that hit West Papua, Indonesia, on Oct 4.

"The earthquake in Manokwari was not felt at the LNG project location. The operation is running normally," said BP Indonesia country head Nico Kanter.

Indonesia's Geophysics, Climatology, and Meteorology Agency said the epicenter of the quake was 123 km northwest of Manokwari, West Papua, at a depth of 56 km.

The announcement follows reports last week that piped supplies of Indonesian gas from South Sumatra to Singapore—which account for more than a third of the city-state's needs—were not disrupted by a 7.6-magnitude earthquake in West Sumatra on Sept. 30.

The report followed checks by the Singapore importer, Gas Supply Pte. Ltd. (GSPL), with ConocoPhilips, the field operator.

GSPL, a subsidiary of Temasek Holdings, imports 350 MMscfd of gas from Grissik, South Sumatra, representing 37% of total Singapore imports of 940 MMscfd currently.

Enbridge, Chevron to bring Big Foot oil ashore

Enbridge Inc. has signed a letter of intent with Chevron USA Inc., Statoil Gulf of Mexico LLC, and Marubeni Oil & Gas (USA) Inc. to construct and operate a 40-mile, 20-in. OD oil pipeline from the proposed Big Foot ultradeepwater development in the Gulf of Mexico.

Enbridge has already announced plans to construct the Walker Ridge Gathering System, providing natural gas transportation for the proposed Chevron-operated Jack, St. Malo, and Big Foot fields.

The Big Foot Oil Pipeline will reach depths of up to 5,900 ft, transporting as much as 100,000 b/d to a subsea connection on existing deepwater pipeline infrastructure.

Chevron initiated front-end engineering and design in March of a hub to develop Jack and St. Malo fields. The production facility would have capacity of 120,000-150,000 boe/d. Chevron estimates combined recoverable liquids reserves of the two fields at more than 500 million bbl (OGJ Online, Aug. 1, 2009).

Enbridge estimates the cost of the Big Foot Oil Pipeline, about 170 miles south of the Louisiana coast, at about $250 million. Combined with the Walker Ridge Gathering System project, ✦

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.

2009

OCTOBER

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

Expandable Technology Forum, Houston, +44 (0) 1483 598000, e-mail: sally.marriage@otmnet.com, website: www.expandableforum.com. 14-15.

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.

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale/. 19-23.

Oil and Gas Transportation in the CIS and Caspain Region Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 20-22.

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

PICT-Passive Inflow Control Technology Meeting, Copenhagen, +44 (0) 1483-598000, e-mail: Dawn.Dukes@otmnet.com, website: www.inflowcontrol.com. 27-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

North African Oil and Gas Summit, Tunis, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremideast.com. 27-29.

Vietnam Saigon Oil and Gas Expo, Saigon, +49 40 30101 266, +49 40 30101 936 (fax), e-mail: industrial.pr@sgs.com. website: www.sgs.com/industrial. 29-31.

NOVEMBER

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 5.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO2symposium.com. 5-6.

Sulphur International Conference and Exhibition, *Vancouver*, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.sulphurconference.com. 8-11.

Gas Turbine Users International (GTUI) Annual Conference, Calgary, Alta., +9714 804 7738, +9714 804 7764 (fax), e-mail: info@gtui.org, website: www.gtui.org. 8-13.

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

Multiphase User Roundtable-South America, Rio de Janeiro, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-sa.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Digital E&P Event, Houston, (646) 200-7444, (212) 885-2733 (fax), e-mail: cambrosio@wbresearch.com, website: www.digitaleandp.com. 9-11.

NPRA/API Operating Practices Symposium, Dallas, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 10.

Petroleum Association of *Wyoming (PAW)* Annual Oil & Gas Statewide Reclamation Conference, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: cheryl@pawyo.org, website: www.pawyo.org. 10.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 10-12.

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NPRA International Lubricants & *Waxes* Meeting, Houston, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 12-13.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

Latin America LPG Seminar, Miami, (713) 331-4000, (713) 236-8490 (fax), e-mail: ts@purvingertz.com, website: www.purvingertz.com. 16-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

Energise Your Future Forum, Paris, +33 0 1 47 96 91 68, e-mail: claude.leonard@bostik.com, website: www.energiseyourfuture.com. 18-20..

DECEMBER

Advanced Contract Risk Management Europe for Oil & Gas, Aberdeen, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.contractriskmanagement.MAC=11579.003EDIARY. 1-2.

Journally Speaking

The qualified recovery

Bob Tippee
Editor

Call it the qualified recovery.

It's the resumption of global economic growth that seems to have begun but that cannot be discussed without a host of qualifications.

Markets show signs of life. But unemployment lingers. Expansion is slow. Risks abound. So far, qualifications outnumber hopeful signs. After the crash of 2008, any improvement is welcome.

Instead of "hip-hip-hooray," however, the more reasonable response is "hip-hip, and get back to work." Or the job search.

Oil markets have been anticipating recovery since the price of crude scraped bottom at the turn of the year. Traders, when they're not arbitraging oil against the dollar, seem to be using equity prices as heralds of rebounds in economies and oil consumption.

They'll be right someday. For now, demand's still down from last year, and inventories and idle production capacity remain high. Until those relationships change, the crude price will be shaky. And they won't change until the global economy regains health.

Intensive care

If the economy isn't yet out of the hospital, it's at least sitting up in bed, according to the International Monetary Fund's new World Economic Outlook.

But it still needs intensive care.

"The global economy is expanding again, and financial conditions have improved markedly," say IMF Economic Counselor Olivier Blanchard and Financial Counselor Jose Vinals. "It will take some time, however, until the outlook for employment improves significantly."

IMF expects the global economy to expand by 3% next year, well below preslump growth rates. Last year the economy contracted by 1%. Manufacturing and inventory rebuilding lead the upturn. Other bright spots are gradually stabilizing retail sales, reviving consumer confidence, and strengthening housing markets, IMF says.

Growth is strongest in the developing world. Real growth in gross domestic product will approach 5% in 2010 for the group of countries IMF calls emerging economies. Last year, GDP for this group grew by 1.75%.

For advanced economies, IMF says, expansion will remain "sluggish," with unemployment rising, through much of next year. The year's GDP expansion for this group will be about 1.25%, compared with contraction of 3.5% in 2009.

IMF credits central banks and governments for triggering the rebound and suppressing fears about a worldwide depression.

Central banks slashed interest rates and took "unconventional measures" to inject liquidity and sustain credit. Governments launched stimulus programs and supported banks with guarantees and capital injections.

"Together, these measures reduced uncertainty and increased confidence, fostering an improvement in financial conditions, as evidenced by strong rallies across many markets and a rebound of international cash flows," IMF says.

The group points out, however, that "lower-tier borrowers" remain stressed and that "the risk of a reversal is a significant market concern."

Eventually, fiscal stimulus will subside, and inventory rebuilding will lose influence. Consumption and investment will have to sustain economic momentum, but they're slow coming back. So the recovery might stall, IMF concedes.

Also, governments might abandon accommodative monetary and fiscal policies—economic intensive care—"because the policy-induced rebound might be mistaken for the beginning of a strong recovery in private demand."

In fact, IMF warns, the "fragile global economy still seems vulnerable to a range of shocks." Risks include rising oil prices, a resurgence of H1N1 flu, geopolitical events, and resurgent protectionism.

While surprisingly rapid improvement in financial conditions raises hope that consumption and investment might recover faster than expected, the agency says, a longer term risk looms.

It's that public skepticism about bailouts of financial firms might limit support for financial restructuring and foster prolonged stagnation. What's more, the cure may yet poison the patient. "The greatest risk," IMF says, "revolves around deteriorating fiscal positions, including as a result of measures to support the financial sector."

Oil markets

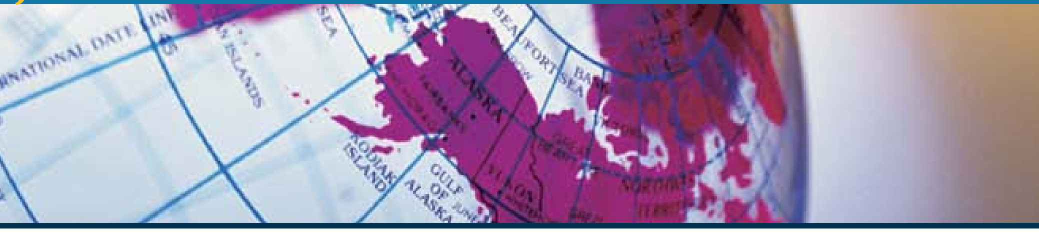
IMF isn't the only group publishing forecasts about the global economy, of course. But its outlook drives oil market forecasts by widely watched analysts such as the International Energy Agency.

Last January IEA said it bases oil demand projections on demand forecasts by IMF, the intergovernmental Organization for Economic Cooperation and Development, and Consensus Economics, a London-based survey of 700 economists.

In September, IEA added 500,000 b/d to its demand outlooks for this year to 84.4 million b/d and for next year to 85.7 million b/d.

Both levels of consumption would fall below those of 2007 (86.5 million b/d) and 2008 (86.3 million b/d).

Hooray still must wait. ✦



PennEnergy EQUIPMENT
WWW.PENNENERGYEQUIPMENT.COM

Four 58-MW Rolls-Royce Trent GTGs Available for Immediate Delivery

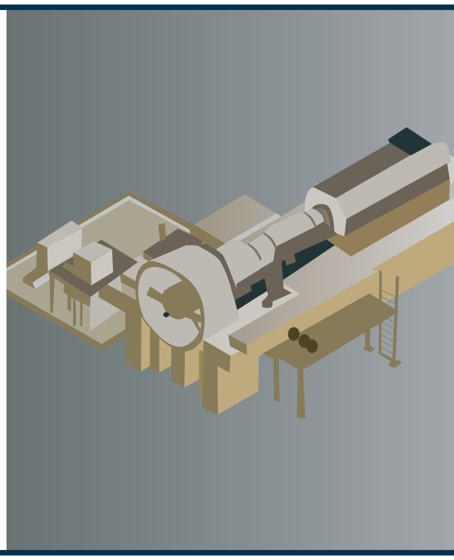
The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.



Unused GE D11 HP/IP Turbine Assembly Available for Immediate Sale

All parts professionally stored in Pensacola, Florida

Unused GE D11 HP/IP turbine assembly and other miscellaneous parts including LP casings and 304-MW generator stator now available for immediate sale.

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

Solar Centaur 40 T4701S Turbine Generator Package with approximately 60,000 accumulated hours at 50% load. Package was in service from 1999 until August 2007. Engine is BACT compliant with OEM 25 ppm Nox/50 ppm CO guarantee. Operates off SAB-type Ideal generator rated at 3500 kW, 4375 kVA and 13,800 volts at 60 Hz. Miscellaneous equipment includes inlet air filtration and simple exhaust systems, and auxiliary control console with start/stop/sync/control.

Williams®

For Info or Pricing
Contact

Randy Hall rhall@pennenergy.com P: 713-499-6330 | Bart Zaino bzaino@thomassenamcot.com P: 817-263-3273

The deepwater royalty win

A Supreme Court decision upholding the meaning of a law does not represent legislative malfunction in need of repair. Oil and gas producers, however, might yet have to argue the point.

In refusing on Oct. 5 to review an appellate court's decision backing Anadarko Petroleum Corp. in a dispute over deepwater royalty relief, the high court provided a reminder that law is the law. To some lawmakers, however, laws favoring oil and gas producers are unpalatable.

The case

The case addressed eight deepwater leases issued in 1996, 1997, and 2000 to Kerr-McGee Oil & Gas Corp., now part of Anadarko. Because of their issue dates and water depths, the leases automatically qualified for suspension of federal royalty under the Deep Water Royalty Relief Act of 1995. Automatic eligibility applied to leases awarded in the 5 years ending in 2000.

Dispute centered on inclusion by the US Minerals Management Service of price thresholds in deepwater leases issued in 1996-97 and 2000. The move suspended royalty relief when oil and gas traded below the thresholds. When the Department of the Interior in 2006 ordered Kerr-McGee to pay royalty on the eight leases for high-price periods after 2002, the company sued, arguing price thresholds lacked statutory basis. Deepwater leases issued in 1998-99 contained no price thresholds.

The law, in fact, specifically authorizes price thresholds for leases issued before 1996 and after 2000. For 1996-2000 leases, however, it limits royalty relief by production volume rather than price.

So why did Congress treat deepwater leases issued in 1996-2000 differently from those issued before and after that period? The answer lies in budget-neutrality rules in place at the time the legislation was passed. Sponsors created a 5-year window for automatically eligible deepwater leases, knowing production wouldn't start until after the window closed. They thus dodged the need to offset forgone royalty with new revenue.

Because lawmakers didn't want relief available with new leases to pull exploration and development away from existing leases, the law allowed holders of leases in effect at the time of enactment to apply for royalty relief on the basis of economic need. But it made that relief, as well as relief provided at MMS's discretion after 2000, subject to price thresholds. The section of the law dealing with leases issued in the 5-year automatic-eligibility window sets volume limits and doesn't mention price thresholds.

These distinctions make clear that the intent of the law was to stimulate deepwater investment by making royalty relief, subject only to volume limits, automatically available for 5 years. And the clear result is success. The law accelerated development of a now-thriving deepwater industry vital to energy supply, prosperity, and technology. For producers and for the US, it was a good deal. And refusal by the Supreme Court to hear Interior's last appeal means the deal Anadarko and other producers thought they had is the one the government must uphold.

Industry antagonists in Congress will take a different view. According to press reports, for example, Rep. Ed Markey (D-Mass.), complained after the Supreme Court decision that the oil and gas industry "stands ready to see a geyser of tens of billions of dollars in windfall profits at the expense of American taxpayers." Estimates of the ultimate value of deepwater royalty relief vary greatly, depending as they must on forecasts of production and prices.

Political threat

In the past, Markey has sought to exclude producers from federal leasing unless they either renegotiate deepwater leases containing royalty relief not subject to price thresholds or pay special fees. His first effort failed. But a kindred idea appears in the administration's budget proposal in the form of a new Gulf of Mexico production tax designed to offset deepwater royalty relief.

A Supreme Court victory thus will reinvigorate a political threat to oil and gas producers. Two important questions lie at the center of the issue: Does Congress mean what it says when it writes laws? And how much confidence can anyone have in deals with the US government?

Producers shouldn't hesitate to ask them. ✦

Drawdown uncertainty among issues for SPR

Jude Clemente
San Diego State University
San Diego

Perhaps no national security strategy reinforces the ability of the US to defend itself and maintain reasonably normal economic activity during a disruption in oil supply more than the Strategic Petroleum Reserve (SPR). The Department of Energy calls the emergency crude oil reserve, created in 1975 in response to the Arab oil embargo 2 years earlier, "the nation's first line of defense against an interruption in petroleum supplies."

Since 1985, SPR has been tapped twice to supplement supply and minimize economic damage during an oil shortage: in 1991 (during operations Desert Shield and Desert Storm in Kuwait) for 21 million bbl, and in 2005 for 11 million bbl (after Hurricane Katrina). DOE plans to expand SPR storage capacity to 1 billion bbl by 2018 from the current 727 million bbl.

SPR uses four underground salt caverns along the Gulf Coast holding 724 million bbl of federally owned oil. This strategic supply, which is enough import cover for nearly 60 days, has a maximum drawdown rate of 4.4 million b/d for 90 days. Fig. 1 illustrates the significance of this amount in satisfying US oil requirements—including the ability to maintain national defense.

RIK program

Since 1999, SPR oil generally has been filled with crude acquired by the government through the royalty-in-kind (RIK) program in use on federal offshore leases. A recent decision by the

COMMENT

interior secretary to phase out the RIK program will return SPR purchases to a cash basis.

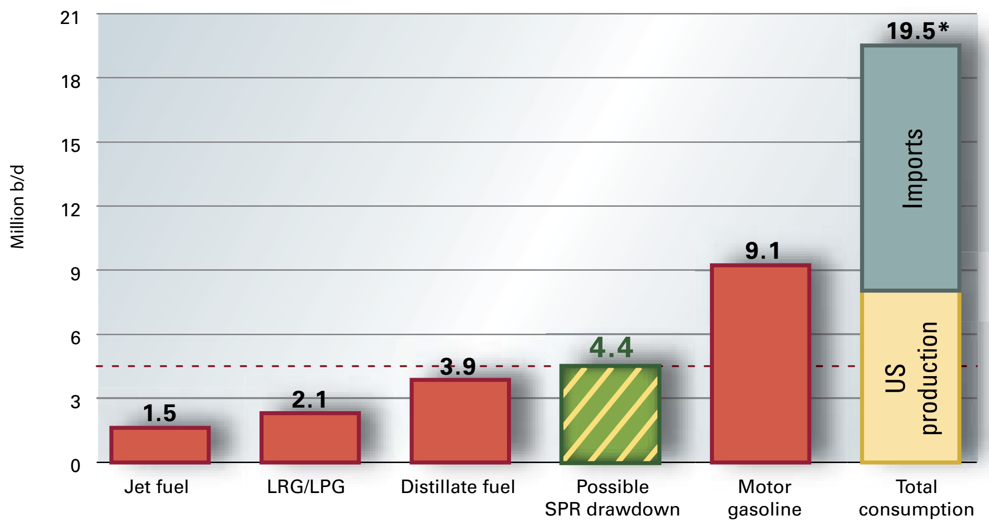
Sales of SPR occur at the discretion of the president. They begin with notices of sale outlining the details, after which prospective buyers submit bids, which are subject to DOE review. The time between a presidential decision to release SPR oil and physical entry of the oil into the market is about 2 weeks.

In May 2008, the federal government suspended SPR fill, the rate of which had been about 70,000 b/d, in an effort to reduce prices. The futures price for light, sweet crude on the New York Mercantile Exchange at the time was above $120/bbl. The SPR suspension occurred under a law that prohibited further additions to the stockpile until the price fell below $75/bbl.

In his 2007 book, The Strategic Petroleum Reserve: US Energy Security and Oil Politics, 1975-2005, Bruce Beaubouef confirms SPR draw-

SPR POTENTIAL VS. 2008 US OIL CONSUMPTION

Fig. 1



*Lowest since 1998.
Note: Operation Iraqi Freedom in 2004 indicated that the US military, largest single oil buyer in the world, needs 395,000 b/d to fight, 40% more than in peacetime.
Source: Based on data from the US Energy Information Administration.

downs mitigate the economic damage of a disruption in oil supply in four basic ways. Drawdowns, according to Beaubouef:

- Help stabilize and lower oil prices by discouraging excessive speculation, panic buying, and hoarding.
- Reduce inflation, wealth transfers, loss of industrial output, and "consequential economical damage" by mitigating price increases.
- Play a key role in mitigating and reducing, and perhaps preventing, the type of socioeconomic damage that occurred in the 1970s by alleviating oil shocks.
- Allow the US economy time to adjust, recover, and operate more closely to predisruption levels by helping to replace lost supply.

SPR issues

The SPR, however, faces several issues, some of which have been in effect since the program's inception.

One of those issues is uncertainty. Oil ShockWave, a scenario exercise developed by Securing America's Future Energy Future and the National Commission on Energy Policy, in 2005 examined the implications of and possible responses to an oil shortfall, finding that SPR offers "some protection against a major supply disruption." But it said the protection is "limited in both scope and duration."

Participants, a group of formerly high-ranking federal officials, verified that it was "extremely difficult" to reach consensus on when SPR is appropriate for use. The decision to withdraw crude from strategic storage is difficult and somewhat controversial, as the inventory is ambiguously meant to be tapped during a "severe energy supply interruption."

For example, Oil ShockWave participants were uncertain as to whether high prices by themselves constituted the type of emergency SPR is intended to help assuage. Further, the use of the reserves could confirm oil traders' fears of a major crisis, causing prices to increase rather than decrease.

There was broad agreement, however, that SPR could help the US response to an oil shortage by offering some short-term relief. An overall lack of experience in the use of SPR makes a drawdown imperfect and uncertain.

That oil is a global commodity sold on an international market also creates problems for the SPR. Supply disruptions anywhere raise prices everywhere. Therefore, there is concern that unilateral US action, by drawing upon SPR to reduce prices, would benefit consumers worldwide but would be paid for largely by American taxpayers.

Like events after Hurricane Katrina, any use of SPR would have to be coordinated with similar actions by other consuming countries. Still, the effects of globally coordinated inventory withdrawals might be offset by output cuts by producing nations. And there is no guarantee that SPR oil made available will find buyers.

The Congressional Research Service reports there are too many factors involved to predict the effect of an SPR drawdown would have on oil prices.

Oil quality is another issue. According to the Government Accountability Office (GAO), 40% of the oil in SPR is classified as "light sweet crude," and 60% is classified as "light sour crude." These oil grades are not optimum feedstocks for the many US refineries that have been upgraded to process heavy oil.

GAO concluded SPR use could decrease domestic gasoline production by as much as 11% and diesel production by 35%. Of the approximately 5.6 billion bbl of oil that US refiners ran to distillation units in 2006, GAO reports an estimated 2.24 billion bbl (40%) was heavier than that stored in SPR.

Recommendations

These issues suggest recommendations for managing the SPR.

- *Store heavier oil.* To ameliorate problems of compatibility with US refineries, a DOE study indicated that SPR should have at least 10% heavy oil. An added benefit of increasing the heavy-oil share of the storage volume would be lower per-barrel costs of purchased crude.
- *Base SPR purchases on dollar-cost averaging.* GAO suggests "filling SPR by acquiring a steady dollar value of oil over time rather than a steady volume of oil over time as has occurred in recent years."

The constant-quantity path of repeatedly purchasing the same monthly amount is a detriment in times of high prices and makes SPR filling more vulnerable to market volatility. Dollar-cost averaging, on the other hand, offers DOE a monthly allowance, meaning more oil can be bought when prices are low and less when they are high.

- *Reexamine procurement.* Oil companies participating in the RIK program, until it phases out, should be given more flexibility to defer their SPR deliveries when filling would substantially tighten the market or when a price decline is expected. The companies could then provide additional barrels when deliveries resume (DOE has permitted some delivery deferments in the past). Further, GAO notes the evaluation of bids has been more adequate for cash purchases than for RIK exchanges. Cash purchases are generally seen as more transparent and cost-effective.

Pivotal role

SPR drawdowns will continue to play a pivotal role in protecting America's national security. In fact, SPR is the most functional energy security policy tool at hand in the US. It helps maintain the country's petroleum-based economy by making an oil crisis a short-term phenomenon.

Despite a recent decline, DOE's Energy Information Administration projects global demand will jump from 86 million b/d in 2010 to 107 million b/d in 2030.

With some exceptions, major producers are decreasingly dependable and cannot be expected to assuage the effects of a large supply disruption. Physical supply from strategic storage can abate market panic in an emergency.

Drawdown issues must be resolved. ✦

Bibliography

Beaubouef, Bruce, The Strategic Petroleum Reserve: US Energy Security and Oil Politics, 1975-2005, Texas A&M University Press, 2007.

Congressional Research Service, The Strategic Petroleum Reserve: History, Perspectives, and Issues, http://fas.org/, Sept. 19, 2008.

Energy Information Administration, International Energy Outlook, US Department of Energy, May 2009.

Secure Energy, Oil Shockwave: Oil Crisis Executive Simulation, www.secureenergy.org, 2005.

US Department of Energy, Inspection Report: Review of Security at the Strategic Petroleum Reserve, June 2005.

US Government Accountability Office, Strategic Petroleum Reserve: Options to Improve the Cost-Effectiveness of Filling the Reserve, Feb. 26, 2008.

The author

Jude Clemente is an energy security analyst and technical writer in the Homeland Security Department at San Diego State University. He holds a BA in Political Science from Penn State University and an MS in Homeland Security from San Diego State. He also holds certificates in infrastructure protection and emergency preparedness from the Federal Emergency Management Agency, the American Red Cross, and the US Department of Homeland Security. Clemente's research specialization is energy security at the international level. He can be reached at judeclemente21@msn.com.

WGC09: Gas, LNG making inroads despite global recession

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

Speakers on the first day of the 24th World Gas Conference in Buenos Aires consistently noted developments in the past 3 years few had anticipated at the last event in 2006.

The most obvious certainly has been the 2008-09 global financial crisis, immediately depressing energy demand with the worst contraction of business activity since the 1930s.

The two major forces in the evolution of natural gas trade in the past 3 years have been a decisive transformation to a global gas trade and development of North America's unconventional gas supply.

Expanding gas trade, pushed by the growth of LNG production and proliferation of LNG regasification terminals, has moved the gas industry closer to its dream of breaking out of regional geographic restrictions.

Combined with the growth in LNG supply, however, has come the unexpected resurgence of gas supply in North America from unconventional sources. This surge in volume coupled with depressed demand due to the recession prompted some speakers here to forecast a time in the not-too-distant future when North America becomes self-sufficient in gas supply and joins the world's LNG exporting nations.

Gas demand growth

In his opening keynote address, Antonio Brufau, Repsol chairman and chief executive officer, addressed the competition for markets between gas and coal. He said gas demand will increase "more than what was expected, to the detriment of coal [demand for which] will recede."

Brufau was one of several speakers who cited coal's problem with carbon capture and sequestration (CCS) "plagued with unproven large-scale technologies."

Echoing his viewpoint later was the International Energy Agency's Ian Cronshaw. Contrary to his and others'

WGC09: IGU issues gas industry study to 2030

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

Results of a major study by the International Gas Union of natural gas demand out to 2030 formed the basis for an extended panel on the first day of the 24th World Gas Conference in Buenos Aires.

The study's main conclusion was that economic and environmental factors should push global gas demand to more than 4 trillion cu m/year (about 141.2 tcf) by 2030, from about 3 trillion cu m currently.

The study also concluded that a global political agreement to put a high cost on carbon dioxide emissions and to encourage renewable energy "would only be economically successful" in combination with an increased share of natural gas. "The right policies" would boost gas to 28% of the global fuel mix by 2030 from 21% today.

The study compared two 2030 scenarios: one from IGU experts that represents a continuation of current policy trends and another IGU "green-policy" scenario.

Primary energy demand under continued policies would reach 16.5 billion tonnes/year of oil equivalent in 2030. Of this, natural gas would represent 23%, or 4.3 trillion cu m. Carbon dioxide emissions from all fuels under this scenario would reach 41.6 billion tpy.

Under the green-policy scenario, however, primary energy demand would reach 15 billion toe/year in 2030. Of this, natural gas would represent projections, he said, gas demand during the current recession has increased, not lost ground, in competition with coal.

CCS, on which coal depends for it to compete in current and future environmentally conscious marketplaces, is "at minimum 10 years away," said Cronshaw.

J. Mark Robinson, formerly a commissioner with the US Federal Energy Regulatory Commission and currently president of JMR Energy Infra LLC, also said coal depends on CCS, and CCS depends on the capacity of industry to build dedicated pipelines for carbon dioxide, something he calls an "asphyxia," for which political concerns will likely preclude siting permits.

Nuclear power, said Robinson, is also problematic because final project costs cannot adequately be estimated at the first of the project.

Renewables, yet another competitor with gas, require land and transmission lines. Again, said Robinson, the public does not want large areas of empty land used as sites for wind or solar facilities nor does it want an extensive growth in electricity transmission lines.

Brufau said, independent of whatever energy policies are implemented, the "weight of primary gas consumption will be stable or grow," adding, "This viewpoint is based on one of the historically most stable long-term patterns: the ratio between gas consumption and per-capita income is stable or upward with the economic growth of countries."

Brufau also noted that countries expected to have rapid economic growth are emerging countries with low and medium per-capita income, "representing two thirds of the world's population.

"If we believe in the economic growth of these countries, then we must believe in the growth of gas demand. If we expect China and India to continue the patterns of per-capita gas consumption seen in other more advanced countries we should bet on steady gas demand."

The sector accounting for the largest gas demand growth has been and will continue to be electricity. He cited the fact that about 1.5 billion people lack access to electricity and that urbanization in emerging countries "goes hand-in-hand with electricity consumption," implying that consumption would increase.

Growing trade

Several keynote speakers and panelists on the first day of the triennial conference noted the rapid growth in global gas trading. This growth threatens to allow gas to break out of the historical regional constrictions on its trade.

Brufau called attention to the "historical pattern in the industry that is the growing weight of the international gas trade and the increasing share of LNG in it." And he said this pattern will be "projected into the future."

The reasons for it are well-known: Conventional reserves exist for more than 60 years and the geographical distribution of reserves among the main global regions implies that "future regional interdependence and international gas trade will both increase."

Brufau said, "In this context of globalization, …recent developments will favor a bias towards geopolitical considerations and towards policies geared to ensuring the security of supply."

More than one speaker or panelist called attention to the other significant event in the last 3 years: the growth of

28%, or 4.8 trillion cu m. Carbon dioxide emissions from all fuels under the "green policy" would reach only 27.7 billion toe/year, compared with 30 billion toe/year currently. The green-policy scenario envisions an agreement in Copenhagen later this year and reinforcement around 2020 of global climate-change policy that leads to further change as 2030 approaches.

The report shows, said its announcement, that combining a global agreement that "sustains a high cost of carbon" with policies that continue to "promote IGU sustainability principles" can lead to a "dramatic improvement" in carbon emissions.

"Governments would need to acknowledge that such a policy must be consistent with the maintenance of energy security and the encouragement of optimum economic choice," it said.

supplies in North America for unconventional gas developments.

Robinson noted how estimates of gas reserves in the Marcellus shale alone have increased by orders of magnitude; we "don't know how much gas is really in the shale," he said.

The "real question," according to Robinson, is whether the US will join the group of gas-exporting countries in the near future.

Brufau said unconventional gas, as shown in North America, "is a new variable" that will have to be taken into account for any long-term view.

"From now on we will have to bear in mind the relative cost of developing unconventional gas and the fact that unconventional gas production responds very rapidly to changing demand and price conditions," he said.

Will any of the large LNG producers restrict their production in response to markets, such as the US, where prices are soft and supply is ample? That question was addressed by another keynote speaker, Qatargas Chief Executive Officer and Chairman Faisal al-Suwaidi.

"I doubt that will happen," al-Suwaidi said, noting that overall, LNG demand is growing. "Prices in some markets, especially the mature ones, may be down but [natural gas demand] in the newer markets, especially China and India will balance the more mature markets, especially the US," he said.

With its large trains and vessels, Qatargas is in LNG trade for the long term, he said; LNG is "a long-term business," adding, "People in this business shouldn't watch the prices daily. Over the next several years, prices will fluctuate."

Noting that both Qatargas and RasGas remain under a LNG production capacity ceiling of 77 million tones/year, Suwaidi nonetheless believes each of the 6 megatrains (at 7.8 million tpy/train) could "easily be increased" by 2 million tpy after Qatar Petroleum lifts its moratorium on new gas production from North field and, thereby, its restriction on the two LNG companies. ✦

EPA's proposed GHG rule targets refineries, large plants

Nick Snow
Washington Editor

The US Environmental Protection Agency proposed regulations on Sept. 30 that would subject refineries and other large industrial operations to greenhouse gas (GHG) regulation under the Clean Air Act while exempting smaller businesses and farms.

Under the proposal, industrial facilities emitting at least 25,000 tons/year of greenhouse gases would have to obtain construction and operating permits covering those emissions. The permits would have to demonstrate use of best available control technologies and energy efficiency measures to minimize GHG emissions when plants are built or significantly modified, EPA said.

"This is a commonsense rule that is carefully tailored to apply to only the largest sources: those from sectors responsible for nearly 70% of US greenhouse gas emissions sources," EPA Administrator Lisa P. Jackson said in a keynote address at the California Governor's Global Climate Summit in Los Angeles.

"This rule allows us to do what the Clean Air Act does best: reduce emissions for better health, drive technology innovation for a better economy, and protect the environment for a better future, all without placing an undue burden on the businesses that make up the better part of our economy," she said.

The American Petroleum Institute and the National Petrochemical & Refiners Association each criticized the proposal in statements given Sept. 30. The US Chamber of Commerce applauded the plan's exemption of smaller businesses and farms, but warned that it could create legal problems. Larger businesses, meanwhile, would be subjected to major new costs and delays, it warned.

14,000 sources

EPA estimated that 400 new sources and modifications to existing sources would be subject to review each year for GHG emissions with the proposed thresholds. About 14,000 large sources, most of which are already subject to clean air permitting requirements, would need to obtain operating permits that include GHG emissions, it said.

Six GHGs would be addressed under what it termed a "proposed tailoring rule," namely carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

EPA said it also is requesting public comment on its previous interpretation of when certain pollutants, including CO_2 and other GHGs, would be covered under the CAA's permitting provisions. A different interpretation could mean that large facilities would need to obtain permits prior to the finalization of a rule regulating GHG emissions, it said.

The proposed rules and more information are posted online at www.epa.gov/nsr/actions.html. Comments will be accepted on the proposals for 60 days after their publication in the Federal Register, the agency said. API and NPRA responded immediately.

API said in a statement that it and several other groups do not believe that the CAA was designed to address GHG emissions. "We also question whether EPA has the legal authority to modify the threshold established by Congress in the act to regulate pollutants, such as GHG emissions," it said.

'Not isolated'

The proposal illustrated the perils of forcing GHG regulations into the CAA, NPRA Pres. Charles T. Drevna observed in a separate statement. "This proposal incorrectly assumes that one industry's greenhouse gas emissions are worse than another's," he said. "Greenhouse gas emissions are global in nature, and are not isolated to a few select industries."

The CAA "stipulates unequivocally" that the major sources' permitting threshold is 250 tons for criteria pollutants, Drevna noted. "EPA lacks the legal authority to categorically exempt sources that exceed the [CAA's] major source threshold from permitting requirements, and this creates a troubling precedent for any agency actions in the future," he said.

Referring to the proposed regulation's exemption of smaller businesses and farms, "common sense prevailed at EPA and we are thankful," said Bill Kovacs, senior vice-president of environment, technology, and regulatory affairs at the US Chamber of Commerce. "However, we fear this proposal rests on shaky legal ground," he said, adding, "As a result, EPA may have only kicked the problem down the road, or into the courthouse, and may have to regulate all small businesses should some environmental groups prevail in likely lawsuits."

In a statement, the chamber said the proposal's provision requiring plants emitting 25,000 tons or more of GHGs annually to get preconstruction permits, which could cost hundreds of thousands of dollars and take from 8 months to more than a year to obtain. This would put major roadblocks in domestic efforts to build new major facilities and projects as the country tries to work its way out of the recession and provide affordable and reliable energy for the future, the business advocacy organization warned.

Chamber cited EPA data showing that a typical CAA Prevention of Significant Deterioration permit costs a regulated entity $125,000 and takes

Watching Government

Nick Snow, Washington Editor

Blog at www.ogjonline.com

GOP freshmen speak up

Freshman members of Congress traditionally sit back and learn during their first year in office. A few Republicans on the House Natural Resources Committee spoke up instead on Sept. 16 at the first day of hearings on chairman Nick J. Rahall's (D-W.Va.) far-reaching federal minerals management reform bill.

Mike Coffman (R-Colo.) confronted US Sec. of the Interior Ken Salazar, who was there to testify, about his "blocking energy development across the board." John Fleming (La.) asked Salazar whether DOI had determined what constitutes diligent development of a federal lease.

Then there was Bill Cassidy (La.), who observed that Rahall's bill "creates contradictions in calling for more expeditious production while it increases bureaucratic delays."

Cassidy brings a unique perspective to the committee, OGJ learned a few days later. He's not the only physician among the GOP members: Paul C. Broun (Ga.) is a general practitioner who introduced a bill on Oct. 1 aimed at curbing excessive legal challenges to energy resource development. But he doesn't come from a major producing state. Cassidy does.

Positive impacts

"When you grow up in Louisiana, you grow up knowing the positive impacts oil and gas and the petrochemical industries can have," he said. "As a physician, I would ask patients where they got their healthcare benefits. Most were from businesses associated with, if not part of, these industries."

Cassidy's point? Oil and gas E&P creates good jobs. "There are few domestic industries which have continued to provide comparable benefits for blue-collar workers in the recent economic downturn," he said.

Radio talk shows in his home district regularly get calls from listeners asking why E&P hasn't expanded so more US workers could get decent healthcare coverage, he said.

When he visited a rig in Pointe Coupee Parish recently, Cassidy said he found that most employees there had high school educations, were married, and drove fairly new vehicles. "From pipe-fitters and welders to barge operators, they appreciate their benefits," he said.

'Less dependent'

Cassidy finds the idea unrealistic that the US won't depend on foreign oil supplies in the near term. "We can be less dependent by increasing our own production," he said, adding that recent strikes off Louisiana show that reports of the death of domestic discoveries are premature.

States with tight shale gas formations, like the Marcellus, could reap major economic benefits from their development, he added.

"We need to think imaginatively about where our domestic supplies are. Dilly-dallying on offshore leasing and finding ways not to proceed onshore is not the way to begin," he said.

Cassidy said, "I'm here to advocate for pipe-fitters, truck drivers, and others in the oil and gas industry," he said. "But others would benefit from more domestic development." ✦

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

866 hr to complete. The requirement to obtain these permits takes effect as soon as EPA makes the rule effective, the group added.

Covered facilities also would have to get Title V operating permits, which effectively would make them pay a $25-40 carbon tax for the first 4,000 tons of GHGs emitted, it said. Each regulated entity also could be subject to a lawsuit by any US citizen, according to the chamber. ✦

GAO assesses impacts, challenges of mandated biofuels increases

Nick Snow
Washington Editor

A federal tax credit of 45¢/gal established to help the domestic ethanol industry probably won't stimulate production beyond levels that new renewable fuels standards specify for this year unless oil prices climb significantly, the Government Accountability Office said.

The Volumetric Ethanol Excise Tax Credit also may no longer be needed to stimulate US corn-based ethanol production because the industry has matured, its processing is well understood, and its production capacity is already near the effective RFS limit of 15 billion gal/year, GAO said in a report issued on Oct. 2. A separate $1.01 tax credit is available for producing advanced cellulosic biofuels, it noted.

It noted that in December 2007 Congress passed the Energy Independence and Security Act (EISA), which requires the use of ethanol and other biofuels to rise from 9 billion gal in 2008 to 36 billion gal in 2022. "To meet the RFS, domestic biofuels production must increase significantly, with uncertain effects to agriculture and the environment," it said.

The report said to meet the RFS, the US Departments of Agriculture (USDA) and Energy (DOE) are developing advanced biofuels that use switchgrass, corn stover, and other cellulosic biofuels. The US Environmental Protection Agency administers the RFS, it added. GAO said it extensively reviewed scientific studies, interviewed experts and agency officials, and visited five DOE and USDA laboratories as it prepared the report.

Higher prices

GAO said for agriculture, many experts believe biofuel production has contributed to crop increases as well as higher prices for livestock, poultry, and, to a lesser extent, food. "They believe that this trend may continue as the RFS expands," it said.

"For the environment, many experts believe that increase biofuels production could impair water quality by increasing fertilizer runoff, and also reduce water availability, degrade air and soil quality, and adversely affect wildlife habitat," the report said.

"However, the extent of these effects is uncertain and could be mitigated by such factors as improved crop yields, feedstock selection, use of conservation, and improvements in biorefinery processing," it added.

GAO said except for greenhouse gas emissions, EPA currently is not required by law to assess environmental effects to determine which biofuels are eligible for inclusion in the RFS.

GAO said many researchers interviewed for the report suggested there is general agreement on the approach for measuring biofuels production's direct effects on lifecycle GHG emissions but disagreement about how to estimate the indirect effects on global land use change, which EPA is required to assess in determining RFS compliance.

"In particular, researchers disagree about what nonagricultural lands will be converted to sustain world food production to replace land used to grow biofuels crops," GAO said.

Challenges loom

The US will face several key challenges in expanding biofuels production to achieve the standard's 36 billion gal requirement in 2022, the report said.

"For example, farmers face risks in transitioning to cellulosic biofuels production and are uncertain whether growing switchgrass will eventually be profitable," it said, adding, "USDA's new Biomass Crop Assistance Program may help mitigate these risks by providing payments to farmers through multiyear contracts." US ethanol use also is approaching the so-called "blend wall"—the amount of ethanol that most vehicles in the country can use—given EPA's 10% limit on gasoline's ethanol content, the report said.

"Research has been initiated on the long-term effects of using 15% or 20% ethanol blends, but expanding the use of 85% ethanol blends will require substantial new investment because ethanol is too corrosive for the petroleum distribution infrastructure and most pipelines," it said.

"Alternatively, further R&D on biorefinery processing technologies might lead to price-competitive biofuels that are compatible with the existing petroleum distribution and storage infrastructure and the current fleet of US vehicles," it added.

The report recommended that in addition to the GHG emissions analysis required under EISA, Congress may want to consider requiring the EPA administrator to develop a strategy assessing the effects of increased biofuels environment on all stages of the lifecycle (cultivation, harvest, transportation, conversion, storage, and use) and to use this assessment to determine which biofuels are eligible for consideration under the RFS. "This would ensure that all relevant environmental effects are considered concurrently with lifecycle [GHG] emissions," GAO said. ✦

Supreme Court rejects DOI appeal of Anadarko case

Nick Snow
Washington Editor

The US Supreme Court rejected a US Department of the Interior appeal of a lower court's ruling in an offshore royalty case that DOI said could cost the federal government $19 billion.

Justices declined, on Oct. 5 without comment, to hear DOI's appeal of the Fifth US Circuit Court of Appeals in New Orleans Jan. 12 ruling that Anadarko Petroleum Corp. does not have to pay $350 million of royalties on eight federal Gulf of Mexico deepwater leases it holds.

Kerr-McGee Oil & Gas Corp., which originally obtained the leases and that Anadarko acquired when it bought the Oklahoma City-based producer in 2006, argued in a legal challenge that the 1995 Deepwater Royalty Relief Act waived payments until specific amounts had been produced.

The US Department of Justice, on DOI's behalf, argued that royalties were due because oil and gas prices climbed past thresholds. The federal government could lose up to $19 billion if other deepwater producers followed suit, DOJ attorneys said.

Responding to the high court's action, US Interior Secretary Ken Salazar noted that the leases were issued between 1996 and 2000, and that DOI took the position under the administrations of Bill Clinton and George W. Bush that royalties should be collected once oil and gas prices reached specific levels.

"In my view, they were correct. We will work with all involved in the days ahead to determine the best way forward," Salazar said.

The Supreme Court's rejection of the appeal "definitely affirms" the lower court's decision that Congress, when it passed the deepwater royalty relief act, provided that relief based on volume limits and not price, American Petroleum Institute Pres. Jack N. Gerard observed in an Oct. 5 statement.

"That act was passed at a time of historically low crude oil prices to increase production and sustain jobs in a struggling industry," he said. "It was enormously successful, helping to boost deepwater [GOM] production by 50% in less than a decade. This production, which Congress considered would likely remain in the ground for years without the royalty relief program, helps boost our domestic supplies and keeps jobs at home."

Gerard said that the 1995 was an example of constructive congressional legislation which encouraged development of domestic resources and achieved the desired results. "Going forward, we trust that Congress will continue to pursue constructive energy policies that benefit the American people, while resisting the urge to take steps that attempt to change the rules of the game midstream and that discourage investment," he said.

But US Rep. Edward J. Markey (D-Mass.), who serves on both the House Energy and Commerce and Natural Resources committees, said the lease agreements were faulty and producers have drilled on federal offshore acreage for free as a result.

"The Supreme Court's refusal to hear Kerr-McGee's brazen lawsuit means that the oil industry now stands to see a geyser of tens of billions of dollars in windfall profits at the expense of American taxpayers," he said on Oct. 5. "At a time when the federal budget is already in the red, this lawsuit means that oil companies can drill here, drill now, and pay never."

Markey said the House has approved a bill he sponsored that would require producers holding such leases to renegotiate the terms before they would be allowed to acquire new tracts. The Congressional Research Service has concluded that the measure would protect the federal government from losses due to royalty-free drilling, he said.

"The minerals below our public lands belong to the American people and no company should be allowed to exploit them for free," Markey said. ✦

EIA: Gas storage to hit record at heating season start

Nick Snow
Washington Editor

US natural gas inventories are expected to reach a record peak of 3.85 tcf when storage injections end on Oct. 31, the US Energy Information Administration said in its latest short-term energy outlook.

Nearly 3.59 tcf was in storage on Sept. 25, 481 bcf above the 2004-08 5-year average and 491 bcf above the level during the same week in 2008, EIA said Oct. 6 in its new forecast. The projected Oct. 31 level would be about 285 bcf above the previous 3.565 bcf record reported for the end of October 2007, it said.

Households heating with gas can expect to spend an average of $105, or 12%, less this winter as a result, EIA said. The decline represents an 11% decrease in prices and a 1% decrease in consumption, it indicated.

The Henry Hub spot gas price averaged $3.06/Mcf in September, 17¢/Mcf below August's average, the forecast said. "EIA expects prices to remain low through October, then begin to increase as space heating demand picks up this winter and economic conditions improve," it said. "Prices are expected to increase in 2010 but, even with a projected winter storage withdrawal greater than the 5-year average, end-of-March inventories still will be the highest recorded since March of 1991."

One day earlier, the American Gas Association said consumers could expect lower average bills this winter because of plentiful supplies and lower wellhead prices. "With natural gas storage at all-time highs and prices well below past years, homeowners across the nation are in for some well-deserved relief from high energy costs," AGA Pres. David N. Parker said during an Oct. 5 briefing.

Likely staying low

Severe weather and other factors still could affect gas demand and prices, Parker said. Barring extreme temperatures for extended periods, however, gas prices will likely stay low this year because utilities buy the fuel from suppliers throughout the year and store it underground, he said. "When they were purchasing gas to put into storage during the spring and summer months, wellhead prices were way down," he said.

In its forecast, EIA said it expects total US marketed gas production will increase by 1.5% in 2009 and decrease by 3.8% in 2010. Marketed gas production in the Lower 48 states rose by 2.9% year-to-year this year through July despite a more than 40% decline in the working rig count during the period, it noted. "While production has remained stronger than expected through much of the year, EIA expects the pullback in drilling to lead to a 3.6% decline in Lower 48 production from the first half to the second half of 2009," it said.

In addition to the natural rates of decline from producing wells, EIA said its current forecast assumes some additional curtailments as gas inventories begin to swell toward capacity limits this month.

"Although the working rig count has begun to increase slightly in recent weeks, EIA expects domestic natural gas production to continue to fall, with marketed production during the first half of 2010 to average 1.8 bcfd lower than the second half of 2009," it said. "However, economic recovery and increasing demand next year are expected to push prices up and provide the incentive for increasing production later next year."

It forecast increases in US LNG imports to about 471 bcf in 2009 and 660 bcf in 2010 from 352 bcf in 2008. Higher LNG imports may occur temporarily as cargoes are redirected from Europe, where storage is reaching capacity and prices have declined, EIA said.

"The start-up of several large LNG supply projects in 2010 will lead to an increase in US LNG imports, although previous supply additions abroad have been slowed by construction delays and feed-gas shortages that contribute to EIA's uncertainty about the future of current projects," it said. ✦

France, Kazakhstan seal long-term energy accords

Eric Watkins
Oil Diplomacy Editor

Doris Leblond
OGJ Correspondent

Kazakhstan President Nursultan Nazarbayev and French President Nicolas Sarkozy, eyeing broader geopolitical engagement between Europe and Central Asia, have signed a number of agreements between their two countries involving oil and gas.

"We signed 24 agreements," said Sarkozy, adding, "A new page is being written in the history of relations between France and Kazakhstan…a partnership that we have signed with a long future."

Nazarbayev said, "An agreement has been reached on the French side's participation in the project to construct the main export oil pipeline from the Caspian Sea to Baku and Europe."

He was referring to the draft agreement signed by a consortium of French companies headed by Spie Capag (Vinci group) for the siting of a pipeline between the offshore Kashagan oil field and Baku that will enable oil to be carried to Europe.

"This is an exceptionally important project, which forms the base of the arteries of the transport system for Kazakh gas and oil to Europe," Nazarbayev said.

Sarkozy agreed, saying, "This oil pipeline is going to create many jobs here and in France" and "will furthermore guarantee the security of our energy supply."

Kazakhstan 'long courted'

As one observer noted: "Kazakhstan has long been courted by Western governments for its energy wealth and also as an alternative supplier to Russia, the source for 25% of the gas sold to European Union countries."

The pipeline agreement, one of several between the two countries involving oil and gas, will bypass Russia and increase Europe's energy security by diversifying its sources of supply. At the same time, the project will boost Kazakhstan's economic security by diversifying its markets.

In addition to the pipeline agreement, Total and GDF Suez signed a heads of agreement with Kazakhstan's state-owned KazMunaiGas (KMG) to acquire half of its 50% stake in Khvalynskoye gas field, which straddles the Russian-Kazakhstan border in the Caspian Sea.

According to the Kazakh foreign ministry, ownership of the project comes down to KazMunayGas 25%, Total with GDF Suez 25%, and Lukoil 50%. Within that framework, Total will hold a 17% stake in the development consortium and GDF Suez will hold 8%.

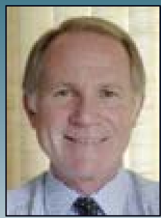
No figure was available relating to the purchase price of the 25% stake, but the two French firms will jointly invest $1 billion in the field's development.

Khvalynskoye field, which lies in 25-30 m of water, is operated by Lukoil. Its development will take place under a production-sharing agreement cur-

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



Oil diplomacy in Romania

If there is anything the oil and gas industry has learned in Romania recently, it's that Europe and Central Asia are determined to establish an energy bridge that bypasses Russia.

That was the resounding message that emerged from the Black Sea Energy & Economic Forum, organized in Bucharest over Sept. 30-Oct. 2 by the Atlantic Council.

The message was underscored by many speakers, but none more clearly than in a reminder by Fabrizio Barbaso, deputy director general, Directorate General for Transport and Energy, European Commission.

"The gas crisis in January 2009 between Ukraine and Russia was a painful reminder of the strategic importance of energy security to Europe," Barbaso said.

Real shock

"The crisis forced European citizens to suffer from the winter cold, and negatively impacted on our industrial output," Barbosa said, adding, "This came as a real shock for many Europeans."

As a result of that shock, Barbosa noted, "The 27 EU Heads of State meeting in the European Council in March 2009 underscored the urgency of clear guarantees from suppliers and transit countries that suppliers will not be interrupted."

In particular, Barbosa said, the 27 EU Heads of State "also vigorously stressed once more the importance of diversifying sources, fuels, and routes of energy supply."

Such diversification was largely diplomatic speak for the need to ensure that the EU does not fall prey to Russia when it comes to matters of energy.

"One of the EU's greatest challenges is to ensure that growing energy dependence does not become a risk to wider economic or international security," Barbosa said.

Russian incursion

Yet, even as the EU and the US develop an energy strategy that bypasses Russia, no one doubts the consequences of shutting the door completely on the Russians. Conference participants needed no reminder of Russia's incursion into Georgia last year, and its disruption of world energy supplies.

Richard Morningstar, US special envoy for Eurasian energy affairs, drew attention to the importance of Russia in the Black Sea and Caspian region, saying, "Russia will continue to be a major player in this region for the foreseeable future."

No less important, Morningstar sounded the diplomatic note: "It's in our interest for Russia to increase its oil and gas production, but that is not inconsistent with encouraging competition and diversification of pipeline routes."

In those few words, Morningstar summed up the new diplomatic dialogue that the West will attempt to develop with Russia: that no harm will come to Russia from the EU's diversification of fuels, suppliers, and routes.

In a word, the West is comfortable with Russia as "a" supplier, but not as "the" supplier. The question, however, is whether Russia can be equally comfortable with that formula.

The West's diplomats have their work cut out for them. ✦

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

rently under discussion with Russian authorities.

Under an agreement signed by Kazakhstan and the former Soviet Union in 1988, Russia has rights on some borderline fields such as Khvalynskoye field, and all the gas produced there is due for export to Russia.

Total Chief Executive Officer Christophe de Margerie tentatively indicated that the field should come on stream at the earliest in 2016 and production could hover around an estimated 7-9 billion cu m/year. However, officials told OGJ that the full potential of Khvalynskoye has yet to be fully appreciated.

In need of investment

Underlining future business prospects, Aidan Karibzhanov, the managing director of the Samruk-Kazyna national welfare fund, told a French-Kazakh business forum that energy firms in his country need investment.

"If growing demand for energy is to be met, new energy generating capacities must be created and old ones upgraded," Karibzhanov said.

"We can see vast prospects for cooperation emerging in this sphere, the more so since Samruk-Kazyna has capacities, resources and subsidiaries at its disposal, including Samruk Energy and KEGOC, the national electric power lines operator," Karibzhanov said.

The government "has made steps to liberalize the local market and to create a favorable environment for investors," he said. According to Karibzhanov, Kazakhstan has some competitive advantages in the energy sector: access to cheap fuel reserves given a large reserve of coal, oil, and gas, and the availability of a large number of renewable energy sources, including wind, hydro, and solar energy.

Karibzhanov's comments coincided with reports that France's BNP Paribas Bank will extend a €10.2 million loan to the Development Bank of Kazakhstan, largely earmarked for energy projects. According to the Kazakh bank's press service, BNP Paribas opened a €200 million credit line for this.

The funds will be used for financing imports of Finnish equipment within the framework of the investment project to build a gas turbine power plant at the Akshabulak oil field.

"A total of 12 agreements, memorandums, and contracts worth $6 billion was signed at the forum," said Timur Nurashev, head of the Kazakh Industry and Trade Ministry's investment committee. "The French side's concrete investments will comprise $1.8 billion."

The BNP Paribas agreement was signed during the Kazakh-French business forum and was timed to coincide with Sarkozy's visit to the Central Asian nation. ✦

Tengizchevroil to boost output in 2009

Eric Watkins
Oil Diplomacy Editor

The Chevron Corp.-led Tengizchevroil (TCO) consortium will increase its planned production of oil by yearend to 22.5 million tonnes from 21.5 million tonnes, according to a senior Kazakh official.

"Planning is expected to increase TCO's oil production by a million tonnes and there remains an unresolved issue of supplementary flaring of gas in the volume of 33 million cu m," said Vice-Minister of Energy and Mineral Resources Duysenbay Turganov during a conference call.

In January, oil companies operating in the country paid more than 14 billion tenge in fines for excess gas flaring in 2008, according to Murat Rakhimbetov, chair of Kazakhstan's committee on environmental regulation and control.

"KPO (Karachaganak Petroleum Operating) was fined 1.8 billion tenge in damages for the excessive associated gas flaring, TCO paid 1 million tenge in fines, KazGerMunay paid 8 billion tenge, Kazakhoil-Aktobe paid over 4 billion tenge, and CNPC-AktobeMunayGas was fined 767 million tenge," Rakhimbetov said.

KMG-SOCAR agreements

Meanwhile, Turganov's announcement coincided with reports that Kazakhstan's state-owned KazMunaiGaz and State Oil Co. of the Azerbaijani Republic (SOCAR) have reached several agreements to ensure that the rising volumes of Kazakh oil will reach world markets.

The agreements, signed during a visit to Baku by Kazakhstan President Nursultan Nazarbayev, envisage shipments of Kazakh crude by tanker across the Caspian Sea and then by rail from to Georgia's Black Sea ports of Batumi and Kulevi, as well as through the existing Baku-Supsa pipeline.

According to KazMunaiGaz, the agreements cover "joint work on the technical and economic feasibility study for the TransCaspian project, a memorandum of understanding about cooperating in the oil pipeline Baku-Black Sea; and a memorandum about the joint use of gas and oil infrastructure that belongs to SOCAR for the development of Kazakhstan's hydrocarbon reserves."

"These documents are the next step in the development of bilateral cooperation between the two national oil and gas companies in the joint use of SOCAR's onshore infrastructure and the realization of the TransCaspian project, which was set out in an agreement signed in June 2006 by the president of the republics of Kazakhstan, Nursultan Nazarbaev, and Azerbaijan, Ilham Aliev," KazMunaiGaz said.

"The memorandum of joint use of SOCAR's oil and gas infrastructure for developing Kazakhstan's hydrocarbon reserves envisages the placing of orders for commodities, labor, and services necessary to develop Kazakhstan's reserves and determines the next stages in the implementation of this cooperation," the Kazakh firm said.

The TransCaspian project will include oil loading terminals on the Kazakh shore of the Caspian Sea, tankers and vessels, offloading terminals on the Azerbaijan coast of the Caspian Sea and equipment to link into the Baku-Tbilisi-Ceyhan line, KazMunaiGaz said.

Depending on the results of the feasibility study, the parties "will as soon as possible plan to create a project company to realize the TransCaspian project," KazMunaiGaz said.

According to analyst IHS Global Insight, "The agreements between the two state-owned oil and gas firms should serve both countries' interests, giving Kazakhstan additional clarity on exports of future oil production from the Kashagan and Tengiz fields while ensuring Azerbaijan's prime transit role in the export of this growing output."

Tengizchevroil, which is developing Tengiz field in western Kazakhstan, is owned jointly by Chevron 50%, ExxonMobil Corp. 25%, KazMunaiGas 20%, and LukArco 5%. ✦

New York releases Marcellus shale drilling proposal

Paula Dittrick
Senior Staff Writer

The New York State Department of Environmental Conservation (DEC) released a draft proposal to govern potential natural gas drilling activities in the Marcellus shale, specifically horizontal drilling and hydraulic fracturing.

The Supplemental Generic Environmental Impact Statement (SGEIS) outlines safety measures, protection standards, and mitigation strategies that operators would have to follow to obtain permits.

New York Gov. David A. Paterson directed DEC to prepare the SGEIS. The state has not yet allowed any horizontal development of the Marcellus shale.

A public comment period on the draft is open until Nov. 30. DEC will accept comments in writing, either via e-mail, regular mail, direct online submissions, or delivered at public information sessions. Those sessions have yet to be scheduled.

"Well permitting and drilling is expected to be more onerous in New York," than in some other states, Raymond James & Associates Inc. analyst John Freeman of Houston said in an Oct. 1 research note.

"While the rules have not been set in stone, New York has provided a path in which operators could develop the Marcellus shale," Freeman said. "Still it is too early to tell if exploration and production and oil field service companies will be willing to jump through these additional hoops to operate in New York."

Frac fluid disclosures

Proposed predrilling requirements include disclosure of the fracturing fluid compositions and the percentages of chemicals to be used for each well. Before drilling, private water wells within 1,000 ft of the drillsite will be tested to provide baseline information and allow for ongoing monitoring. If there are no wells within 1,000 ft, the survey area will extend to 2,000 ft, the proposal said.

Companies will have to follow Susquehanna River Basin Commission and Delaware River Basin Commission protocols for water withdrawal and also complete a stringent state-required streamflow analysis regarding water withdrawal plans.

Technical compliance proposals call for operators to complete a new "Pre-Frac Checklist and Certification Form" to ensure technical compliance with the permit and to provide details about final wellbore construction and hydraulic fracturing operations.

All operators also would be required to prepare plans for mitigating greenhouse gas emissions, visual impacts, and noise impacts before starting operations.

A section on drilling and postdrilling requirements calls for operators choosing to store fracturing flowback onsite to use steel tanks to protect the environment. Before a permit is issued, the operator must disclose plans for disposal of flowback.

Centralized flowback impoundments are prohibited within boundaries of public water supplies including the New York City watershed.

In principle aquifer areas, the draft proposal calls for state inspectors to be present when operators start to cement wellbore casings. ✦

WGC09: Gas reaches 'premium commodity' status

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

Natural gas has come of age, said George Kirkland, executive vice-president, upstream and gas, Chevron Corp., in a keynote speech on the second day of the 24th World Gas Conference in Buenos Aires.

Once a "second prize to oil," gas is now a premium commodity. To retain this status, he said, and meet projections by the International Energy Agency that it make up 50% of global energy mix by 2030 requires lower development costs, long-term investment, and superior project execution.

Didier Houssin, director of the Directorate of Energy Markets and Security for the International Energy Agency, told conference attendees the global recession has afforded the world an opportunity to address climate change as growth in overall energy demand pauses.

Manage projects

Evidence is growing, said Kirkland, that development costs have started to come off their highs of only 15 months ago. That's an important step, he believes, in encouraging serious, long-term investment.

Such investment must be guided by transparency, predictability, and discipline.

"Stable, predictable, and reasonable terms are needed to ensure investment continues to flow. Taxes, fiscal regimes, sound regulatory structure, and sanctity of contracts must be in place and fit together," he said.

Speaking in light of Chevron's recent commitment to two massive LNG projects—Gorgon and Wheatstone—Kirkland stressed: "We must efficiently and cost-effectively deliver on projects that fulfill our commitments to host governments and buyers."

He said, "This means building projects in a safe, reliable, economic, and environmentally responsible manner.

"Our industry must be proficient at managing large, complex projects with multiple partners in challenging environments."

Climate change

The current economic recession has depressed demand and gas prices from their highs of mid-2008, noted Houssin.

IEA estimates demand in countries of the Organization for Economic Co-operation and Development has fallen by 6.5% in 2009 compared with 2008. And for the first time since World War II, global electricity demand has fallen, Houssin said.

IEA has two concerns, said Houssin: climate change and energy security. "This economic crisis, in depressing demand, has given us a window of opportunity to bring about change."

In the struggle with climate change, "gas comes off better than alternatives because the latter are less proven and take longer to build," he said.

Two patterns in natural gas demand are evident in the near future, he said: demand for electric power generation has been cut in half, and demand among non-OECD nations has increased.

As a result, investments in the near future will slow, which will in turn delay final investment decisions for projects needed to meet growing global energy demands.

With demand likely to recover more quickly than investments, that will put a squeeze on supply. ✦

BC's silent majority key to Queen Charlotte basin oil

Henry Lyatsky
Lyatsky Geoscience Research & Consulting Ltd.
Calgary

The silent majority of British Columbians is the most potent force to unlock the province's rich offshore basins to oil exploration.

Public demand for oil jobs and revenues, coupled with clear evidence of the operators' environmental responsibility, will create the political will to lift the moratorium that blocks exploration today. On a sustained basis, exploration proponents need to provide the public with honest, factual information about the enormous benefits of oil development.

Faced with overcautious provincial and federal governments and noisy environmental and anticapitalist lobbies whose stridency conceals a limited weight of numbers, proponents of offshore exploration have a natural ally in the working British Columbians. With the employment uncertainties of the current recession, investment and job-creation potential offshore makes obvious partners of business and workers.

Geological studies conducted so far indicate that the best oil prospects off BC exist in Mesozoic rocks in western Queen Charlotte Sound,[1-3] perhaps with additional oil and gas targets in other areas and rock formations.[4] Though potential oil and gas traps exist in various offshore BC basins, a major limiting factor is the presence of petroleum source rocks at required levels of organic maturation.

Favorably, the prospective western Queen Charlotte Sound area lies in relatively shallow water on the continental shelf, in a sea free of pack ice or icebergs (Fig. 1).

Oil seeps have been known in the Queen Charlotte Islands for decades. Two dozen exploration wells were drilled on land and offshore without success in the Queen Charlotte and Tofino basins, mostly in the 1950s and 1960s.

The Queen Charlotte Islands and Vancouver Island have so far proved nonprospective, largely due to lack of impermeable cap rock.

The government moratorium imposed in the early 1970s ended exploration offshore, except for a marine seismic reflection survey in Hecate Strait and Queen Charlotte Sound in 1988. Other impediments to exploration arise from environmental concerns and unresolved First Nations claims. A Canada-US maritime-boundary dispute persists in Dixon Entrance between the Queen Charlotte Islands and the Alaska Panhandle.

Earthquake risk will affect oil-infrastructure development. The BC coastal region is part of the circum-Pacific "Ring of Fire" characterized by greatly elevated earthquake activity.

Tremors are frequently felt along the BC coast. Yet, some geological studies indicate the BC coast region is tectonically anomalous in the circum-Pacific ring, and its earthquake risk may be lower than sometimes estimated:[3 5] while earthquakes large and small are many, a city-flattening "Big One" seems less likely than is commonly supposed.

An estimate by Hannigan et al.[4] is that the offshore BC basins contain some 9.8 billion bbl of oil and 43.4 tcf of natural gas.

Such reserve estimates in underexplored frontier basins are fashionable but also usually unreliable and dependent on many loose assumptions. With their somewhat different geologic model, Lyatsky and Haggart[1] abstained from numerical predictions. Regardless, BC boasts a rich and ill-explored oil and gas province off its Pacific coast.

The moratorium

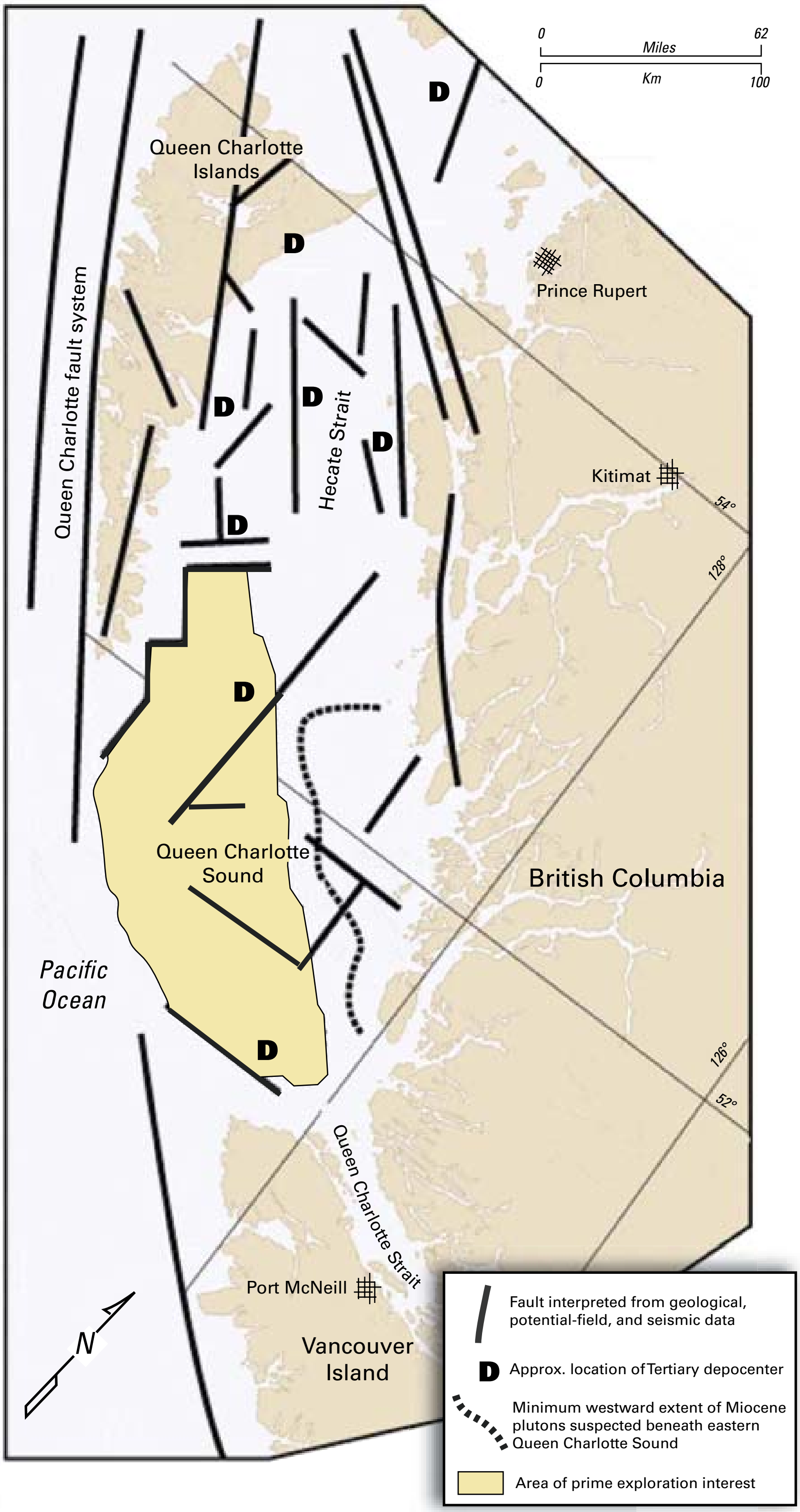
Two separate offshore moratoria stand in the way of oil exploration.

The BC legislature passed a 1971 resolution opposing tanker traffic along the BC coast, aimed to push farther out

This article is based on a lecture, nationally televised in Canada, organized by the Fraser Institute and delivered by Henry Lyatsky at the Calgary Chamber of Commerce in January 2009.

QUEEN CHARLOTTE BASIN GENERALIZED GEOLOGIC MAP

Fig. 1



to sea the Alaska-to-California tankers. In 1972, Pierre Trudeau's federal government made a "policy decision" to approve no new exploration programs and permits off BC and to suspend all obligations under existing ones.[6 7]

Subsequent complications were many. Federal-provincial disputes about offshore jurisdiction wound their way to the Supreme Court of Canada.

After 1984, provincial efforts to lift the moratorium, with public hearings and federal-provincial discussions, continued until the Exxon Valdez oil spill in Alaska in 1989. Then, in the face of real concerns and much hysteria, BC reaffirmed its moratorium. The federal government said it would lift its own moratorium only at BC's request.

After a decade or so of leftish NDP provincial governments that succeeded the business-minded Social Credit, a new BC Liberal government announced early in this decade that it would like to see offshore oil exploration by 2010. There followed a flurry of report writing and task-force discussions, but BC did ask Ottawa to remove the moratorium.

Then came federal reports and reviews, including one by no less than the Royal Society of Canada. Worded cautiously, these reports generally found no compelling reasons to prevent offshore exploration.

But the BC Liberals' offshore enthusiasm waned as they faced reelection against left-wing opposition. Climate-change concerns have also developed an antioil tinge.

Meanwhile, Ottawa acquired a minority Conservative government in 2006, which survives in office at the pleasure of leftist opposition. Split three ways between the Tories, Liberals, and NDP, many federal ridings in BC are sensitive to even small vote swings, leaving the Tories reluctant to rock the boat by raising sensitive local issues.

Federal ministers grow visibly annoyed when questioned about the BC offshore moratorium, and the current federal priority in Canada's offshore oil supply seems to be ensuring national sovereignty in the Arctic. All the federal talk of making Canada into an "energy superpower" stops short at the BC water's edge.

In their heart of hearts, both levels of government probably want the moratorium lifted, but neither wants the hot potato. Neither side wishes to get "blamed" for taking a definitive step, and each would like to shift the public blame to the other. The safest option is to do nothing.

The political scene is now becoming cloudy. The oil-skeptical Obama administration and Democrat-controlled Congress have arisen in Washington, DC, although continuing US thirst for oil is imposing its own sobering inevitability.

The BC Liberal government is in its third consecutive term, with an eventual prospect of return to office of the left-wing NDP. The federal Tories are in their second term of precarious minority, and the thinking of the federal Liberals on offshore oil exploration is a question mark.

Special interests

Despite the extremely noisy anti-drilling lobbies and the lack of sustained pro-exploration public and media efforts, polling indicates British Columbians by a small majority to be in favor of lifting the offshore moratorium.[7]

Wider dissemination of factual information about offshore oil operations can only improve the numbers. The winning strategy for exploration proponents is to go over the heads of governments and special-interest lobbies and address themselves directly to ordinary British Columbians.

Opponents of oil exploration off BC are disparate interests and groups, competing for some of the same supporters and fundraising pools, operating sometimes at cross-purposes, but often united by ideology on the principle of no enemies on the left. While often extremely shrill in their public statements and pressure tactics, they appear to be a concentrated minority at odds with many ordinary British Columbians.

Very notable are groups and individuals variously concerned about environmental degradation, ideologically opposed to resource extraction, hostile to capitalism, suspicious of oil companies or of any large-scale corporate activities, or even nihilists who regard the modern industrial civilization as an unnatural parasite load on the planet. Such groups and persons tend to congregate around the Lower Mainland and southern Vancouver Island, but are found also in the BC interior and up the coast.

Loathing of offshore drilling among such groups can be talismanic. Private statements are often unprintable.

Public and media statements tend to be exaggerated, even fantastic, claims about environmental damage supposedly caused by marine oil development and geophysical surveys, ignoring the ever-diminishing environmental footprint of exploration and drilling and the many decades of environmentally sound offshore exploration and production elsewhere.

Absence of clear federal or provincial environmental regulations for offshore work in BC will also deter investment even if the moratorium is lifted.[6 8] For example, how the federal Species at Risk Act would be applied is unclear; its broad application could be very disruptive to oil activities.

Suspicions abound of anti-industry bias among government bureaucrats who interpret and apply any existing rules. Privately, oil operators often distrust the motives and practices of provincial and federal bureaucrats; some fear excessive use of the precautionary principle in environmental approvals.

A historical anomaly in BC, compared with other western provinces, is the absence of a general system of Indian treaties. This leads to enormous and sometimes overlapping First Nations claims, even in major urban areas.

Negotiations are under way, but to resolve these claims and introduce a treaty system or its equivalent will probably take decades. On the bright side, like many other British Columbians and aboriginal communities elsewhere in Canada, First Nations may conceivably grow to favor oil development if provided with sufficient revenue shares and employment opportunities.

For now, coastal First Nations in BC mostly oppose offshore oil exploration, citing environmental concerns, unresolved land claims, and lack of clarity about aboriginal rights if exploration went ahead.

The Haida Nation of the Queen Charlotte Islands in its constitution claims for itself "the entire Dixon Entrance, half of the Hecate Straits, halfway to Vancouver Island and Westward into the abyssal ocean depths."[6] The rigidity of this ambitious claim in the face of serious negotiations remains to be tested.

The way forward

Latent public sympathy among ordinary British Columbians is the offshore oilmen's strongest weapon.

It persists despite shrill opposition and in the absence of sustained pro-exploration publicity. This sympathy will become broader and deeper if antioil propaganda is countered by honest, balanced, and factual information aimed at the general public.

Investors and operators are well placed to provide the public with honest information about environmentally responsible offshore oil development, as well as about the job opportunities and revenues that would benefit local workers, families, and communities.

Oil industry associations and corporations have a strong track record of winning public support in other Canadian jurisdictions. Lobbying the governments has its place, but in a democracy the general public calls the shots. ✦

References

1. Lyatsky, H.V., and Haggart, J.W., "New petroleum prospects on the west coast of Canada," OGJ, Vol. 90, No. 34, 1994, pp. 53-56.

2. Lyatsky, H.V., "British Columbia's geology holds promise of significant reserves," Offshore, Vol. 63, No. 3, 2003, pp. 34-35.

3. Lyatsky, H.V., "Frontier next door: geology and hydrocarbon assessment of sedimentary basins offshore western Canada," Canadian Society of Exploration Geophysicists Recorder, Vol. 31, No. 4, 2006, pp. 66-75.

4. Hannigan, P.K., Dietrich, J.R., Lee, P.J., and Osadetz, K.G., "Petroleum Resource Potential of Sedimentary Basins on the Pacific Margin of Canada," Geological Survey of Canada, Bull. 564, 2001, 72 pp.

5. Lyatsky, H.V., "Continental-Crust Structures on the Continental Margin of Western North America," Springer-Verlag, Lecture Notes in Earth Sciences 62, 1996, 352 pp.

6. Fogarassy, T., "Legal shoals," Oilweek, December 2003, pp. 19-21.

7. Cook, D., "Stalled offshore," Oilweek, October 2005, pp. 42-46.

8. Cook, D., "Greening B.C.'s deep blue," Oilweek, October 2005, pp. 49-50.

Ecuador

International Sovereign Energy Corp., Calgary, plans to sell its interest in Charapa marginal oil field in Ecuador's Oriente 15 km northwest of the producing Lago Agrio field to state Petroecuador.

Consideration is $3 million and replacement of International Sovereign's $2.34 million performance guarantee to Petroecuador. International Sovereign operates Charapa, which had produced 1.7 million bbl of oil from Cretaceous Hollin and Napo Caliza B at about 10,000 ft before watering out.

The Charapa concession contains three untested and prospective structures. They are Conejo, a seismically defined-drill ready structure 16 km west of the former producing field; Charapa Southwest, a seismically defined structure 5 km southwest of the former producing field; and Halcon, a seismically defined structure in the southwest part of the concession.

Seychelles

Two companies launched a second seismic survey on acreage in the Seychelles in the Indian Ocean off East Africa.

East African Exploration Ltd., a unit of Black Marlin Energy Ltd., Dubai, and Avana Petroleum began shooting 1,100 line-km of 2D seismic to better image potential reservoirs in numerous tilted fault blocks and better delineate leads mapped earlier.

A 3,650 line-km 2D survey in 2007 identified an extensive and deep sedimentary section between and around the granitic islands. The granitic features are linked to those that underpin giant Bombay High field and flank the Cambay basin on India's west coast.

The survey area includes large structures in shallow and deep water and is near wells drilled by Amoco in 1980-81. The wells had oil shows that correlate well with the tar balls occasionally found on Seychelles beaches, suggesting an active hydrocarbon system.

Louisiana

Future Corp. Australia Ltd., Melbourne, took a farmout from Pryme Oil & Gas Ltd., Brisbane, covering 6,400 contiguous acres in Louisiana's updip Tuscaloosa Trend.

Future Corp. will begin to earn a 50% interest in the acreage, known as the Atocha project in East Baton Rouge and East Feliciana parishes, by reentering the Shell Oil Brian-1 well drilled in 1980 updip from Port Hudson field to test 125 ft of bypassed gas pay at 17,700 ft. After that, the two companies will develop other prospects for exploration.

Pryme has a 100% working interest in Atocha and has spent more than $1.4 million building the land position, carrying out technical reviews, and planning a test program.

High-volume ESPs restore oil production in Suriname

E. Anthony
G. Grauwde
Staatsolie Maatschappij Suriname NV
Paramaribo, Suriname

Michael Domangue
Weatherford Artificial Lift Systems
Paramaribo, Suriname

Production

Installation of electric submersible pumps in a field in Suriname proved effective in increasing fluid extraction rates that led to higher oil production and producible reserves, even though wells may have experienced early water breakthroughs.

Staatsolie Maatschappij Suriname NV operates the field in which wells produce heavy 16° gravity oil. The wells are in shallow, high permeability, low-dipping, and very unconsolidated reservoirs that experienced early water breakthrough, short-circuiting significant reserve potential.

The vertical, openhole gravel pack completions produced water-free at 150-300 bo/d for a few months and then plummeted to 25-50 bo/d when water broke through.

Progressing cavity pumps (PCPs) were the primary artificial lift method in the 5.5-in. casing completions.

The company first attempted to install high-volume PCPs to reduce the flowing bottomhole pressure (FBHP) to restore some lost oil production after water breakthrough. Fluid withdrawal rates increased to ±700 b/d from ±350 b/d with no significant change in fluid level, water cut, or oil production.

At second attempt with an electrical submersible pump (ESP) did reduce the FBHP and increased oil production. Fluid withdrawal rates increased to ±2,200 b/d and reduced FBHP by about 100 psi.

The ESPs realized sustained oil production increases of between 100% and 400%. Water cuts increased by no more than 3%. Dynamic fluid levels in surrounding wells showed a temporary reduction, but increased and stabilized at original levels after 2-3 months, indicating a very active edge-water drive mechanism.

The company plans to add infill wells with 7-in. production casing to accommodate larger volume ESPs. It also has not observed any sand production to date, indicating no deterioration of the gravel pack at these elevated extraction rates.

At prevailing oil prices, the project recovered the investment within 4 months.

Suriname operations

The first oil discovery in Suriname was in 1964. Establishment of state oil company of Suriname (Staatsolie Maatschappij Suriname NV) in 1980 led to the drilling of the first test well in 1981, which proved the producibility of the field.[1]

Full-scale development started in November 1982 in Tambaredjo field when five wells produced 250 bo/d.

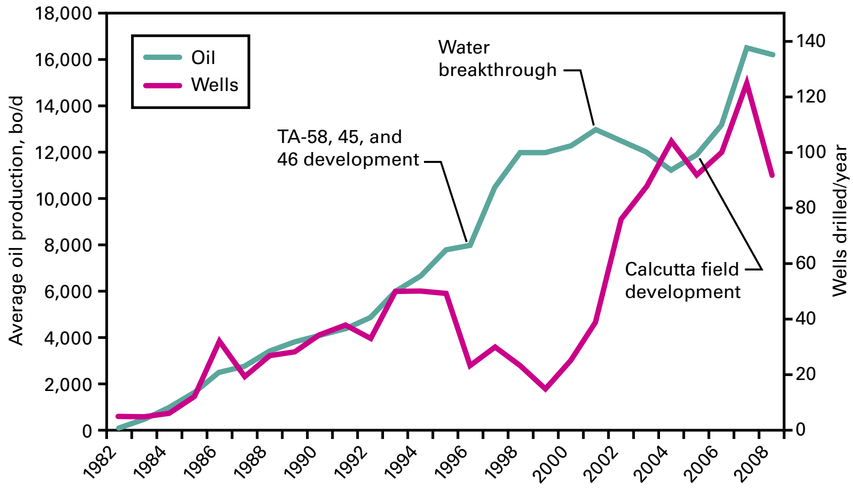
As field development moved further north, the terrain gradually changed from partial swamp to full-scale swamp. Location preparation, interconnecting roads, and facility foundations all required land fill, driving up infrastructural costs.

In 2003, the company drilled appraisal wells in an adjacent field, Calcutta.

In 2006, full-scale development of

STAATSOLIE OIL FIELD PRODUCTION

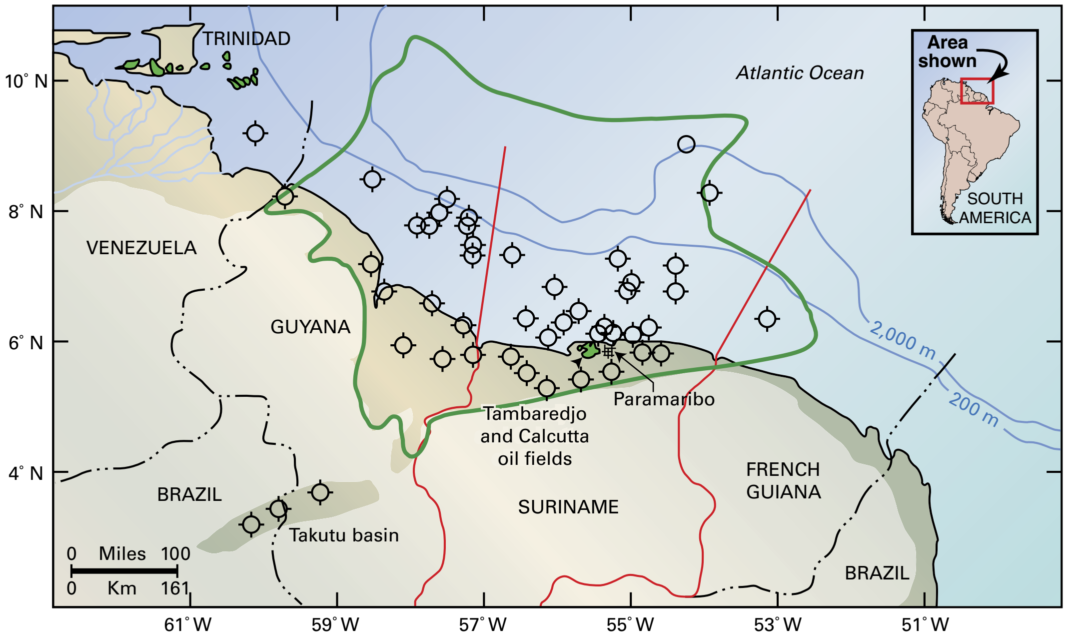
Fig. 1



Based on a presentation to SPE EUROPEC/EAGE Annual Conference and Exhibition, Amsterdam, June 8-11, 2009.

SURINAME-GUYANA BASIN COASTAL PLAIN

Fig. 2



this field started as a wet operation, with wells drilled and completed from pontoon-based drilling equipment. Waterways connect well locations rather than roadways. All pipelines, electric poles, metering, and collection facilities, however, are on landfill dikes.

As of December 2008, both fields produced an average 16,000 bo/d from 1,188 wells (Fig. 1).

The company has appraised a third field and scheduled it for full-scale development in 2010. In addition, it is investigating development strategies for several other fields to reduce infrastructural and operational costs.

Regional geology

The coastal plain of Suriname, together with that of both French Guiana and Guyana, form the onshore part of the Guyana sedimentary basin (Fig. 2).

The reservoirs are of Paleocene age and of a coastal and noncoastal depositional environment (fluvial to shoreface) leading to erratic sand development.

Oil accumulations occur mostly in stratigraphic traps. Combination traps both structural and stratigraphical, however, also are present. These sands are of fluvial-estuarine to coastal marine origin at average 900-1,200 ft depths.

The sands were deposited in a Late Cretaceous unconformity during an overall transgressive period, as multilateral and vertically stacked sand bodies.

The river channels changed their course regularly and rapidly, resulting in a random distribution of the sand bodies over large surfaces. It is therefore difficult to make accurate sand thickness predictions because the stacking pattern of the river bars occurred randomly.

The dominant seal that traps the oil is transgressive shale that overlaps in the south on the Cretaceous surface.

Tambaredjo was the first oil producing field in the relatively unexplored Suriname-Guyana basin.

Reservoir characteristics

Oil production comes from thinly bedded, very unconsolidated clastic reservoirs, with 5-50 ft thickness, 600-1,300 ft depth, and a 95° F. formation temperature. Reservoir pressures are at the hydrostatic gradient.

These reservoirs have an average 38% porosity and 25% water saturation. The oil has average in situ 500-cp viscosity and average 16° gravity. GORs average 70 scf/bbl, seldom exceeding 100 scf/bbl.[2]

The T-sand package consists of vertically stacked sand bodies occasionally interbedded with clay and lignites. The sand body pinches out to the south onto the Cretaceous unconformity and forms a stratigraphic trap, while to the north it dips about 2° (Fig. 3).

The oil-bearing sand thickness varies from 3 to 45 ft with a very irregular lateral sand distribution. This sand distribution pattern results in good producers (>100 bo/d) being offset at no more than 200 m away with poor producers (<20 bo/d).

The sands consist of mostly quartz (95%) and feldspar (<5%). They are very unconsolidated, fine to coarse grained, and poorly to well sorted.

The T-sand reservoirs can be divided into a lower reservoir unit, the T1 sand, middle T2 sand, and an upper T3 sand.

The T1 sand has an average 38% porosity and 7-darcy permeability. The T2 sand and T3 sands have less permeability because of increased clay content.

In the northern part of Tambaredjo, the T1 sand, which is the main producing sand, has an oil-water contact at 1,327 ft.

A combination of solution gas drive, compaction, and water drive supports the oil production in Tambaredjo. Water drive dominates in the northern production areas such as TA45 and TA46.

A Trusted Resource for Accounting Pros

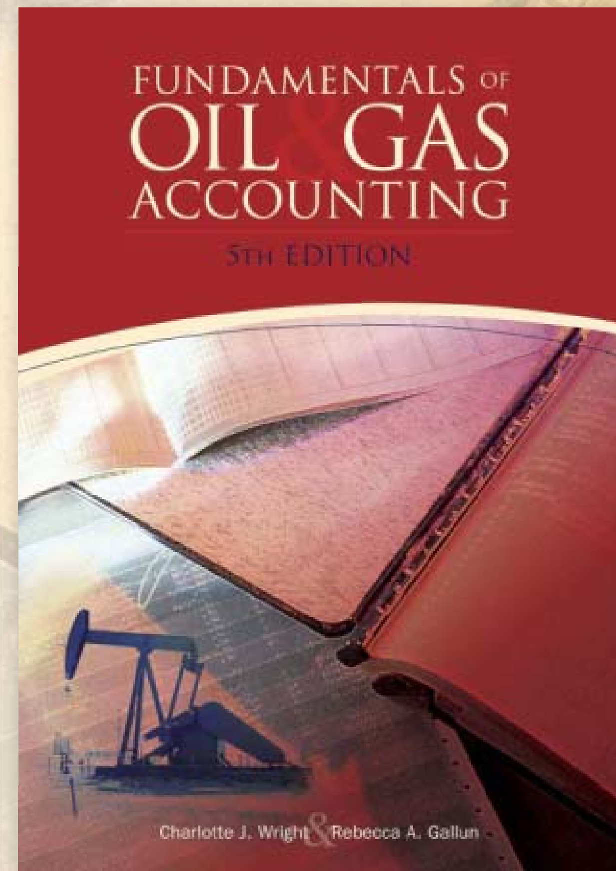
Two of the most respected experts in the field of oil and gas accounting, Charlotte Wright and Rebecca Gallun, have combined their expertise again to update this excellent training manual and professional reference.

Like its best-selling predecessor, the new *5th Edition* of *Fundamentals of Oil & Gas Accounting* is packed with examples, diagrams, and appendices, and its scope is unmatched.

Inside you'll find new and updated material covering

- Current issues facing oil and gas producers operating in the U.S and internationally
- Asset retirement obligations and asset impairment
- Project analysis and investment decision-making
- Asset exchanges and fair value reporting requirements
- Oil and gas pricing and marketing arrangements
- Examples and homework problems

NEW EDITION!



784 Pages/Hardcover/August 2008

ISBN 978-1-59370-137-6

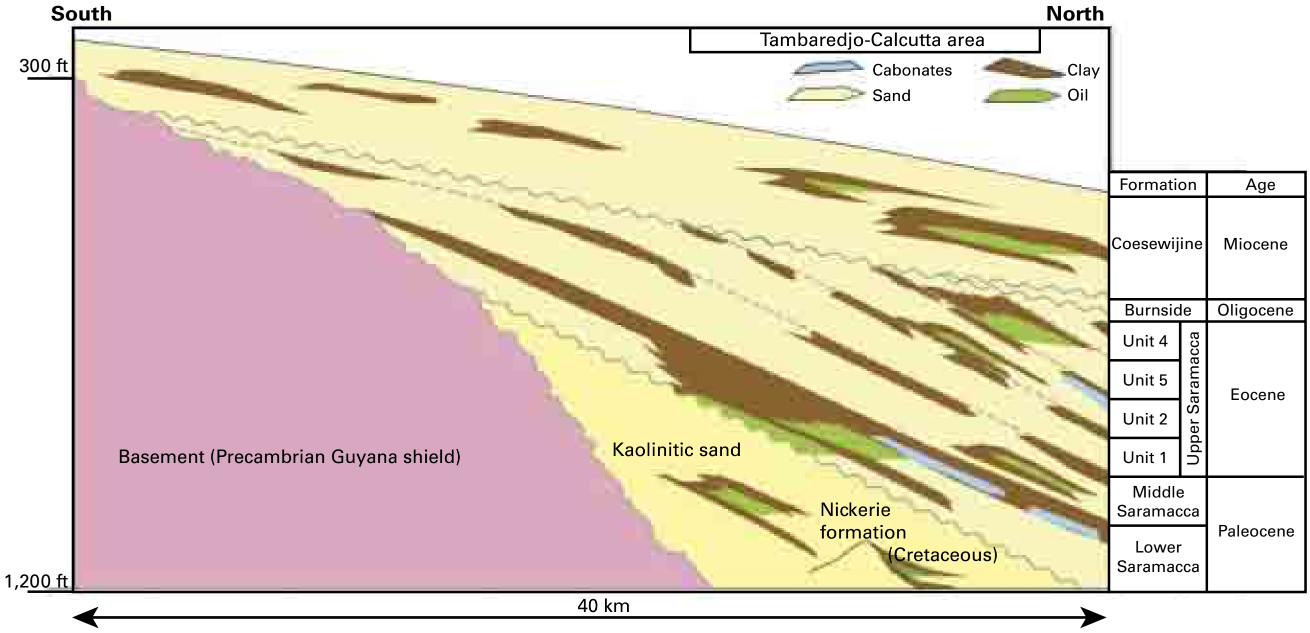
$89.00 US

Buy Your Copy Today!

www.PennWellBooks.com PennWell® 1.800.752.9764

SEDIMENTATION CROSS-SECTION

Fig. 3



Reservoir pressure ranges from 400 to 600 psi, increasing as the reservoir dips towards the north.

Field development strategy

Development of Tambaredjo started in 1982 with a 200-m well spacing. The field required artificial lift from inception because the reservoirs had normal pressure,

Initially the company installed beam pumps but later replaced them with more appropriate PCPs.

More than 95% of the wells in the field are completed as vertical openhole gravel packs with 5.5-in. casing and 2.375-in. tubing (Fig. 4).

As field development moved further north, closer to the regional oil-water contact, the company encountered thicker reservoirs within the T-sand package. Initial production rates from the wells drilled in these thicker reservoirs averaged 200 bo/d as compared with the 30-40 bo/d initial rates from the early development wells to the south.

Hence, as seen at the commencement of development of the TA45, 46, and 58 areas in 1996, the field required fewer new wells to obtain appreciable production growth.

Fig. 5 shows the gamma-ray-resistivity log of a typical well in the area with a balanced bottom cement plug. Drilling and completion practices, however, had remained about the same during this period, and increased productivity primarily was because of the thicker reservoirs.

Fig. 1 shows the production history of Tambaredjo. From 2002, production decreased noticeably because several high oil-producing wells to the north watered out.

These wells continued to produce with 85-95% water cut at oil rates that averaged 25 bo/d compared with the initial 150-350 bo/d.

These early water breakthroughs caused much oil to be bypassed, and the company implemented several techniques for increasing the recovery factor.

Strategies used included:

- Producing wells at low drawdown pressures. This resulted in production rates that remained below the critical coning rate but were below the economical limit to achieve the desired rate-of-return on investment.
- Casing off the target interval and partially perforating the upper section of the oil column. This also led to production rates below the critical coning rates and below the economic level. When rates increased, water breakthrough occurred shortly afterwards due to the high vertical permeability to horizontal permeability ratio in these highly unconsolidated reservoirs.
- Gel squeezes into the wells with high water cuts. Water production decreased but also oil rates decreased proportionally.
- Installing large volume PCPs, limited by the 5.5-in. OD casing, to maximize production rates. Production rates from the largest volume pumps at the time only marginally reduced the FBHP under the high-water cut conditions.[3]

Despite the aforementioned strategies or combinations of them, early water breakthrough left much bypassed oil.

The sources of water being produced in these high-water cut wells was difficult to identify due to the short openhole completed intervals (10-30 ft) at the bottom of the well, and pump installations in place.

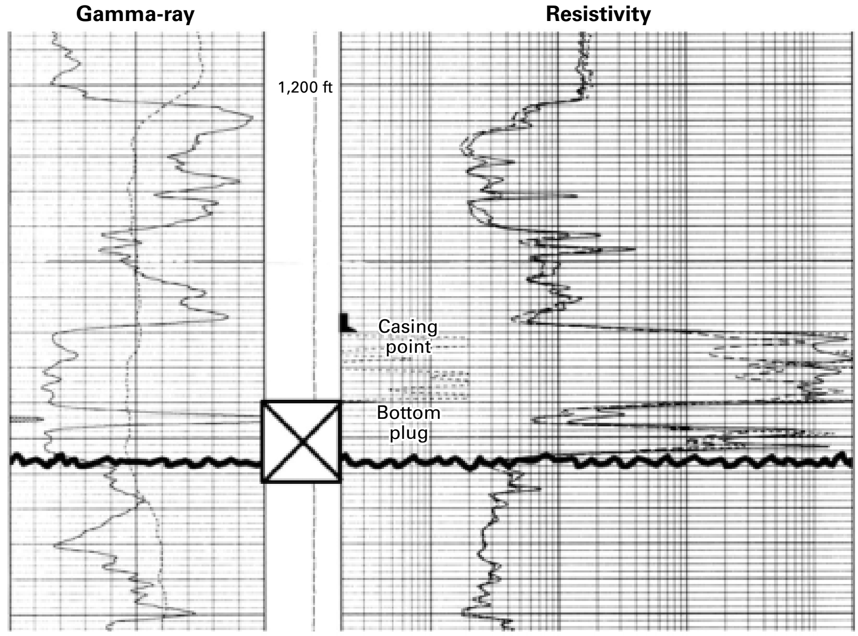
The company considered edge-water underrunning the oil leg as the primary mechanism responsible for the water breakthrough. To a lesser, but still significant extent, is the contribution of water from the underlying, relatively low-permeability Cretaceous beds across the unconformity (Fig. 4).

It decided to increase the drawdown in these wells with appropriate high-volume pumps to allow the bypassed oil to move towards the wellbore.

Due to the limited ID of the field's standard 5.5-in. casing, the company considered PCPs inadequate to achieve the required high water-cut fluid extraction rates.

Typical log

Fig. 4



Well selection

One criterion for selecting wells that could have larger pumps was their ability to produce more than 500 b/d of fluid.

The PCP with largest production volume, at that time, able to fit comfortably in 5.5-in. casing could produce 2 b/d/rpm. At the maximum recommended speed (400 rpm) and at 80% efficiency, the pump could attain maximum rates of ±650 b/d. This rate would reduce the FBHP only marginally.

Another criterion was to have an FBHP greater than 450 psi. At the minimum ESP rate of 1,500 b/d, each well would be required to deliver an additional 1,000 b/d. This only would be possible if there was sufficient reservoir pressure capacity for this extra production without pumping off the well.

A third criterion was to have a water cut between 90 and 96%. Wells with FBHP >450 psi and producing at rates exceeding 500 b/d were inevitably high water-cut wells (>80% water cut).

The lower limit of 90% was picked to avoid selecting well candidates for this project from the existing wells with greater oil production. The upper limit of 96% was selected, so that at the maximum designed extraction rate of 2,200 b/d, the well would produce sufficient oil production to justify the investment should the water cut increase to 98%.

A fourth criterion was for the water-oil ratio to range from 9 to 24 (90-96% water cut) and have remained stable for the last 2 years.

At water cuts >90%, small changes in water cut are visible more readily when displayed as a water-oil ratio rather than percent water cut. For example, a 95% water cut corresponds with a water-oil ratio of 19 and 96% water cut corresponds with a water oil-ratio of 24. The criterion, therefore, was that the trend of the water-oil ratio during the past 2-3 years should not be increasing significantly with time.

A fifth criterion was that the well's productivity index (PI) was greater than 5. A 200-psi pump intake pressure was recommended for securing longevity in ESP operation at maximum rates. The selected wells, therefore, should have a reasonably high PI to reach the 1,500 b/d minimum before the target pump intake pressure reaches 200 psi.

For a minimum additional flow rate of 1,000 b/d, the PI required to reduce the FBHP from 450 psi to 200 psi is 4. A PI of at least 5 includes a safety margin.

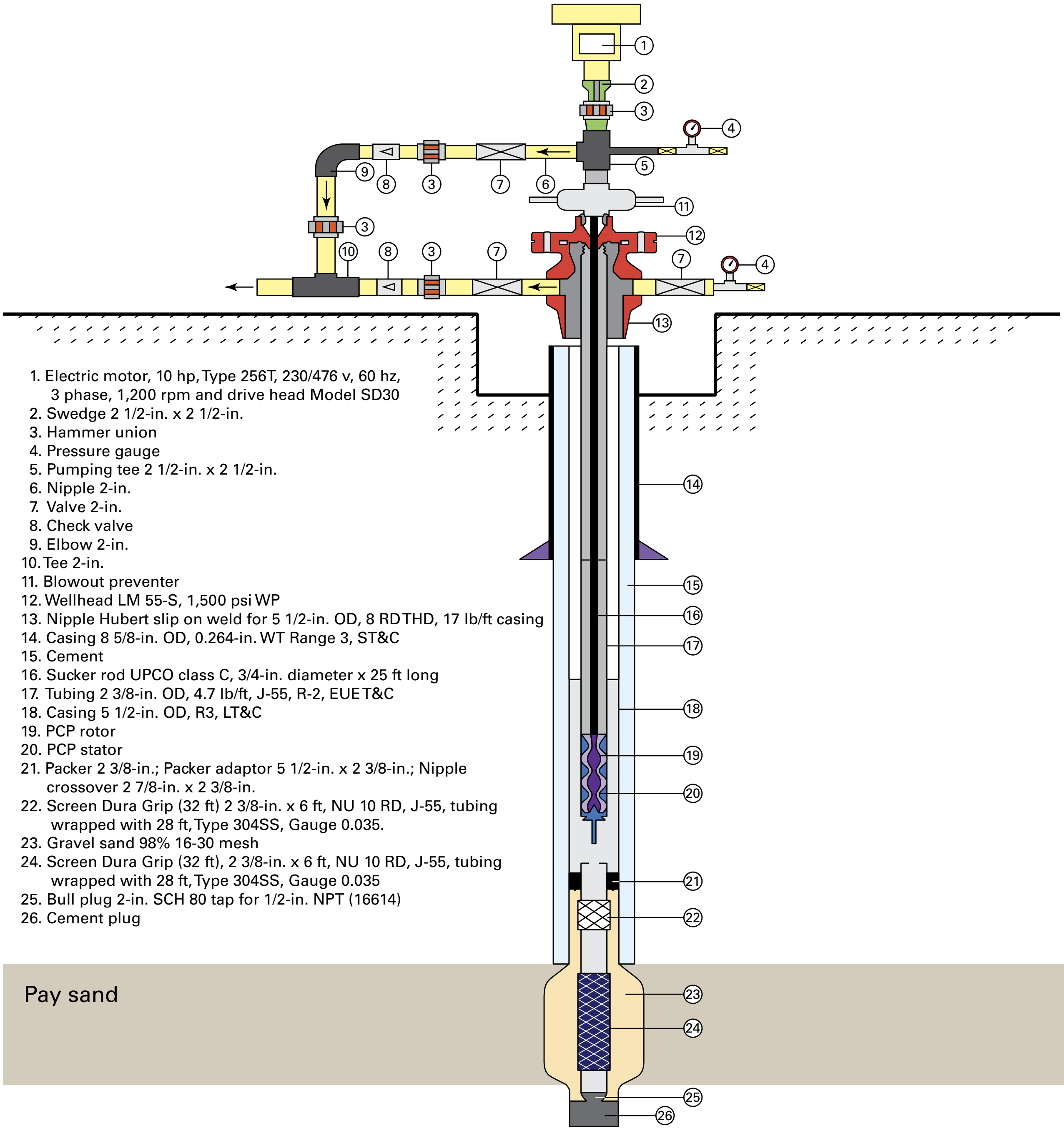
The last criterion was for the wells to have a recovery greater than 20%. Even though wells with low ultimate recoveries indicate significant remaining oil in place, they also have a low recovery rate. These conditions could result from formation damage, early water break through, or high in situ oil viscosity. Wells with a high recovery percentage, on the contrary, show a high potential for favorable oil flow rates to the wellbore.

Due to the pressure support from the edge-water drive in the region under consideration, recoveries greater than 20% within 4-5 years of production were common. This confirms greater potential for higher recovery with additional drawdown than wells with lower recoveries in the same period. These lower recoveries with similar original oil in place indicate wells with formation damage or those too close to the oil-water contact.

From all the wells fitted with the large volume PCP pumps (about 20 wells), 5 wells met all the criteria listed previously. Since budget allocation lim-

PCP openhole completion

Fig. 5



ited this pilot to 3 wells, the company selected wells 9D05, 9D15, and 10A12.

ESP design considerations

The minimum intake pressure recommended for optimum performance of an ESP was 200 psi. Estimated tubinghead pressure at elevated flow conditions was 200 psi (normal THP = 100 psi).

Pump setting depth was about 1,100 ft. Tubing and casing sizes were 2.875-in. and 5.5-in., respectively. The well did not need a downhole gas-separation device because average GORs were about 50 scf/bbl.

The ESP required a variable-speed controller for minimizing the start-up surge on the already heavily loaded electrical distribution system in the field. Minimum and maximum flow rates anticipated were 1,500 b/d and 2,500 b/d, respectively.

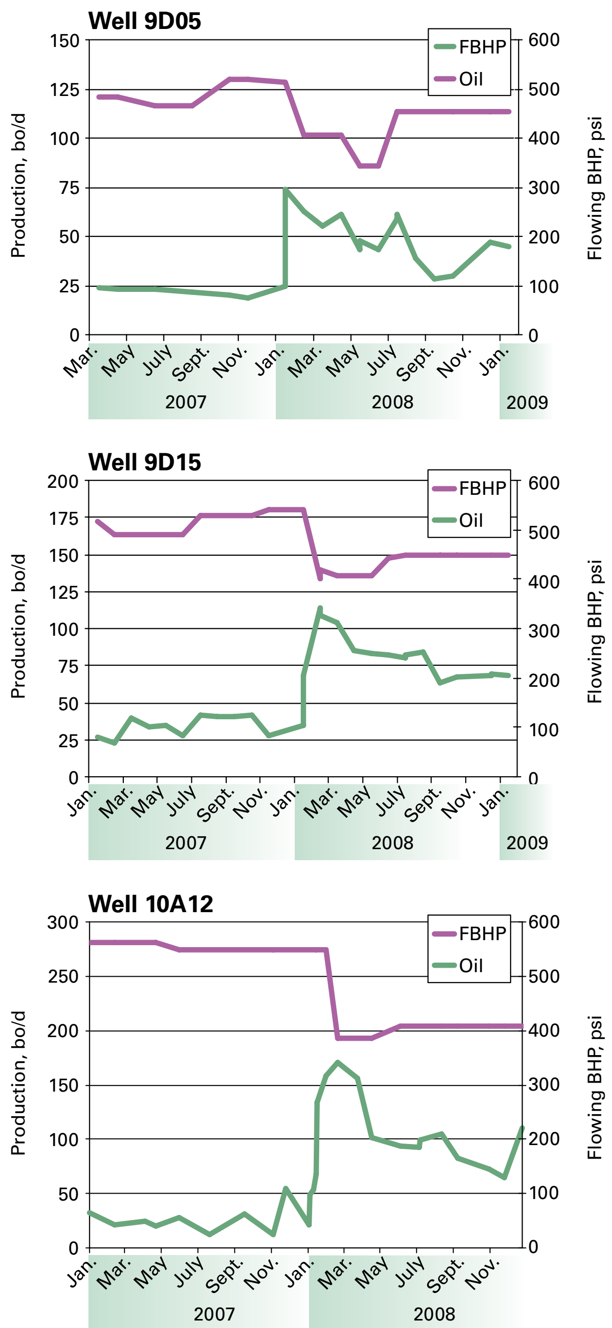
Because no well in the field had

ever been produced at rates greater than 700 b/d, it was unknown if the open-hole gravel pack completion would withstand the elevated drag forces under the higher flow rates. Hence the design called for an ESP with a minimum flow rate equivalent to two times the existing maximum PCP flow rate.

At the minimum flow rate of 1,500 b/d, fluid velocity bypassing the ESP motor was more than sufficient for optimum cooling.

ESP PRODUCTION RESPONSE

Fig. 6



Performance results

Notwithstanding that this was the first experience of running ESPs for the company personnel, they completed each installation within a day-light shift and fitted out all three wells within 3 days. All wells were started at 40 hz (equivalent to 1,500 b/d) without disruption of the electrical distribution system.

Well 9D05 realized an initial 65 bo/d average rate, or a 160% increase from the preinstallation average of 25 bo/d. After 1 year, production rates are 45 bo/d, 80% above the preinstallation rate. It should be noted, however, that the FBHP also increased even though the gross fluid rate did not change (Fig. 6a). Personnel did not detect sand production in any samples taken.

Well 9D15 realized an initial average rate of 109 bo/d, or a 185% increase from the preinstallation 38 bo/d average. After 1 year, production rates are 68 bo/d or 80% greater than the preinstallation rate. Again it should be noted, however, that the FBHP also increased even though the gross fluid rate did not change (Fig. 6b). Personnel did not detect sand production in any samples taken.

Well 10A12 realized an initial average rate of 155 bo/d, or a 450% increase from the 28 bo/d preinstallation average. After 1 year, average production rate is 90 bo/d, or 320% of the preinstallation rate (Fig. 6c). As in the other two wells, personnel did not detect sand production in any samples taken.

Reserves additions

From a combined baseline production of 87 bo/d, the average combined incremental oil gain within the first 3 months combined was 240 bo/d. After 12 months production, the incremental oil gain declined to 116 bo/d.

With decline-curve analysis and extrapolating to normal abandonment, the incremental reserves gained for each well are 14,470 bbl in 9D15, 41,330 bbl in 9D05, and 67,000 bbl in 10A12.

Combined incremental reserves added are 122,800 bbl, about equivalent to 15% of original recoverable reserves determined from decline curve analysis.

Economics

All three wells had identical 35 hp, 48-stage ESPs, each fitted with variable-speed controllers on surface. The cost for all three ESP systems was about $350,000, including equipment and services.

Accounting for water treatment costs, incremental operating expenses from additional power requirements, and oil decline rates of 50%, 40%, 30%, and 20% in subsequent years, the project net present value was $1.68 million with an internal rate-of-return of 310%. The calculation used a conservative $35/bbl oil price.

For a low-tier operation, these are excellent economic returns.

Observations

Despite the average 350% increase in gross fluid production, water cut only marginally increased, not more than 3%. This resulted in the attractive oil production increases realized. To mid 2009, the wells have produced a combined incremental 40,500 bbl of oil.

Except for well 10A12, initial decreases in FBHP after ESP start-up was short-lived, apparently due to the strong pressure support at the water source.

The openhole gravel-pack completions withstood the higher drag forces at the higher production rates much better than expected.

The PI's observed at the increased drawdown indicate significant potential for further oil gains.

The company will have to consider water separation, treatment, and disposal costs if it converts many more wells to ESP production at higher rates.

Since start-up, the ESP installations have not experienced a mechanical or electrical problem.

Well 9D10, the well directly between 9D05 and 9D15, showed negligible response to the increased drawdown in the adjacent wells except for a marginal reduction in FBHP.

Project economics show a payback period of 4 months with a favorable rate-of-return of 310% and net present value of $1.68 million.

Acknowledgments

The authors thank the Staatsolie board of executive directors and their management team for their support and permission to publish this article. Contributions from the Calcutta asset team, field evaluation and development team, and the ESP project team also are appreciated. ✦

References

1. Kartoredjo, H., et al., "Heavy Oil Field Development and Reservoir Management Challenges in Producing Onshore Shallow Reservoirs in Suriname," Paper No. SPE 104068, First International Oil Conference and Exhibition, Cancun, Mexico, Aug. 31-Sept. 2, 2006.

2. Brouwer, G.K., "Reservoir Simulation Tambaredjo Field (TA-45 & TA-58 area)," TNO Report No. B-380, Internal Report, November 2004.

3. McClung, W.J., and Johnson, J.A., "Electric Submersible Pump Application and Operation in Small Openhole Completions," Paper No. SPE 9213, SPE ATCE, Dallas, Sept 21-24, 1980.

The authors

Elred Anthony is the consultant special projects coordinator at Suriname Staatsolie Maatschappij Suriname NV. He previously worked for Petrotrin in Trinidad & Tobago and has more than 25 years' experience in production engineering and completions. Anthony has a BS in petroleum and natural gas engineering from Penn State University.

Guinio Grauwde is leading the well servicing department at Suriname Staatsolie Maatschappij Suriname NV. He is involved in the high water cut strategy of the company and contributes to the completion design for the polymer injection pilot project. Grauwde has an MSc in petroleum engineering from the Technical University of Delft in the Netherlands.

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

More product-sulfur reduction on horizon

Kurt Barrow
Purvin & Gertz
Houston

US refiners have successfully managed a large number of product quality changes related to sulfur reduction while at the same time processing higher sulfur crude oils. Elemental sulfur itself has gyrated through a wild price cycle over the past 2 years.

More changes to US refined-product sulfur qualities are coming on the heels of gasoline and transportation diesel fuel improvements already implemented.

The largest impact will be in the marine sector, in which portions of traditional high-sulfur residual bunker will be replaced with distillate. More reductions are likely for Northeast US heating oil markets.

Sulfur pricing

Sulfur is considered a by-product of refining and not generally a valuable product. It is costly to remove from crude oil and certainly not sought after. As have many commodity prices, sulfur's has gone through a dramatic rise since 2003 and even sharper decline. Fig. 1 represents an estimate of the US Gulf Coast price based on a benchmark pricing source and adjusted for handling costs to remove the sulfur from the refinery.

Image from CB&I's Virtual Refinery

Sulfur supply is relatively inelastic with most on-purpose production shutdown long ago and by-product sulfur accounting for the majority of supply. Historically, surplus sulfur was stockpiled in remote locations, such as Alberta, as the cost of transportation was more than the end-market value. Through midyear 2008, demand for sulfur rose steadily, driven by increased sulfuric acid and fertilizer demand in both the developed and developing markets.

Ethanol and biodiesel production accounted for part of the increase, but higher protein diets in developing markets form the primary driver. Increased demand reduced sulfur inventories, and remote stockpiles were depleted rapidly.

In response, sulfur prices rose quickly through 2007 and into 2008. The financial crisis in late 2008, however, pushed down sulfur prices sharply. The product now has little value and some refiners are paying to have sulfur removed from their plants.

Once the economy recovers, higher costs in the sulfur industry are likely to keep prices higher than historical levels, although lower than recent peaks. New supplies of sulfur from sour gas fields in Abu Dhabi and other Middle East locations could add major new supplies that would restrain any long-term price increases even as demand for sulfur remains strong.

Crude quality

From a refiner's perspective, the location of sulfur in the crude oil is important.

In most cases, sulfur is concentrated in the heavier distillations. Sulfur removal by hydroprocessing becomes increasingly difficult as boiling point increases, requiring higher pressure, temperature, and residence time. Fig. 2 illustrates the sulfur distributions for several benchmark crude oil grades.

As shown, the highest concentration of sulfur lies in the vacuum residue portion of the crude. While the US refining system is probably the most complex in the world, there are still substantial volumes of vacuum residue that are blended to fuel oil and bunker fuels.

Even as refining margins remain weak, product-quality requirements are shifting and nimble refiners will move to capture these opportunities. Before addressing the product quality, it's useful to consider refinery "supply" of sulfur by examining recent crude-quality changes.

Much has been made of the precipitous drop in Maya crude production, which is an important element of the US crude balance. As a result of the drop in US product demand and crude runs, refining crude residue yields have declined as the crude slate has lightened and as less crude is processed through the crude unit. An almost unthinkable result has occurred—spare coking units.

Along with drops in key Latin American supplies, Middle East production cuts alone have removed an estimated 280,000 b/d of vacuum residue from the global market this year through production cuts by the Organization of Petroleum Exporting Countries. This drop in heavy and sour crude supplies has had a similar impact on the refinery sulfur intake.

Fig. 3 shows calculated tons of sulfur in US refinery crude runs. The total sulfur level peaked around 37 million tons/day in June 2005, but hurricane-related and other refinery outages have reduced the value for the next 3 years. Refinery crude run reductions coupled with a lower sulfur crude slate have reduced the value to near 32 million tons since January.

Gasoline

Environmental legislation has moved rapidly over the past several years to reduce sulfur in many but not all refined products. Automotive gasoline sulfur was reduced to 30 ppm in a phased program starting in January 2004.

There are no current plans by the US Environmental Protection Agency to reduce gasoline sulfur further, although European and other markets are at 10-ppm sulfur levels. Refinery naphtha and natural gasoline have no legislative limits, but high-sulfur products can have a commercial price discount if above typical levels.

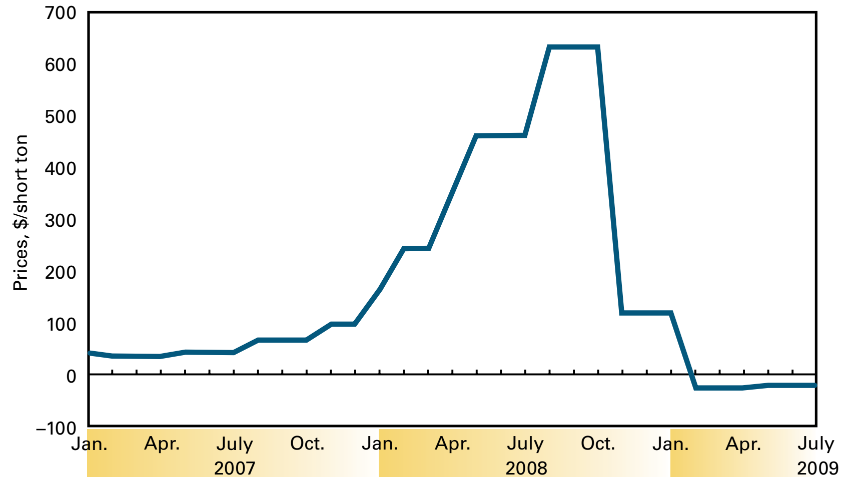
Jet fuel

There has been discussion in the environmental and scientific community regarding the reduction of jet-fuel sulfur. Environmental agencies have studied the issue but at this point, no firm regulatory action appears evident. Based on our understanding of the issues and the science, the benefits of sulfur reduction in jet fuel are modest compared with transportation or stationary fuel sulfur reductions.

That said, there are some benefits to

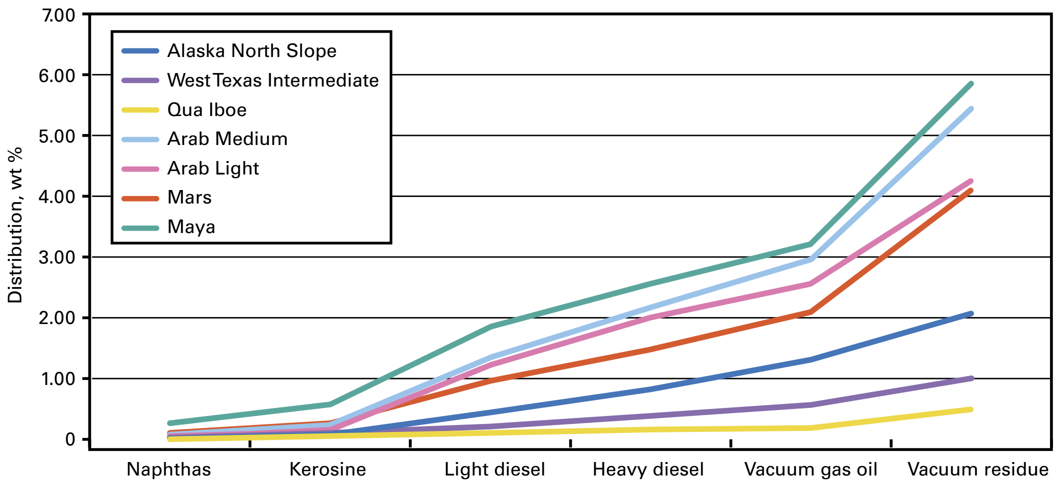
US GULF COAST SULFUR

Fig. 1



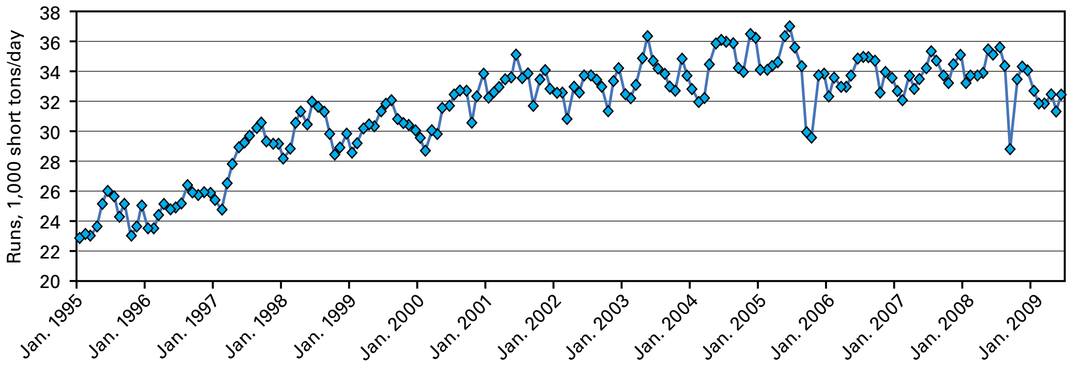
GLOBAL CRUDE SULFUR

Fig. 2



SULFUR IN CRUDE

Fig. 3



sulfur reduction of jet fuel, and it appears logical that jet-fuel sulfur would be reduced to lower levels at some point in the not too distant future.

Jet fuel is one of the most globally harmonized fuels with common specifications around the world for the vast majority of consumption. The two primary specifications, US ASTM D1655 and UK DEF STAN 91-91, are the bases for most country specifications with a few exceptions.

Making changes to these specifications involves participation of aircraft engine manufacturers, country-level regulatory bodies, technical advisory groups and others, not to mention the refining industry. The global nature of the airline industry and jet fuel hinders quick specification changes. The ability of the air transport industry and regulators to achieve a modest reduction (to say 500 ppm) is more probable than a major shift to ultralow sulfur levels.

Diesel fuel

Only about 60% of the distillate pool is required currently to meet the ultralow sulfur specifications, as it is applicable to on-highway product. Even so, many refiners are able to produce 100% ultralow sulfur product. Ultralow sulfur diesel (ULSD) has penetrated other sectors that consume high-quality diesel fuel, such as the farming and off-highway sectors, as a result of logistic constraints as well as strong marketing.

Changes in the sulfur level of the distillate pool have come from both shifting demand patterns and regulatory mandates. Faster growth in diesel demand relative to thermal consumption of distillate (residential, commercial, utility, etc.) resulted in a growing demand share of the lower sulfur on-highway product since its introduction 15 years ago.

Regulations that became effective in June 2006 require 80% of on-highway supply to meet the 15-ppm sulfur specification, moving to 100% in 2010. Off-road diesel sulfur limits were tightened to 500 ppm in 2007 and will be further tightened to 15 ppm in 2010.

No changes have been made to heating-oil qualities in several decades, but there now appears to be state-level legislative action that will reduce the sulfur content, within a few years,

Indian refinery starts up new sulfur-recovery unit

Commercial operation was under way last month at a unique sulfur-processing facility at Reliance Petroleum's Jamnagar export refinery.

The new sulfur-processing unit mirrors the original unit, built in 1999, except that it recovers more sulfur, conforming to newer environmental regulations. Photo from Black & Veatch.

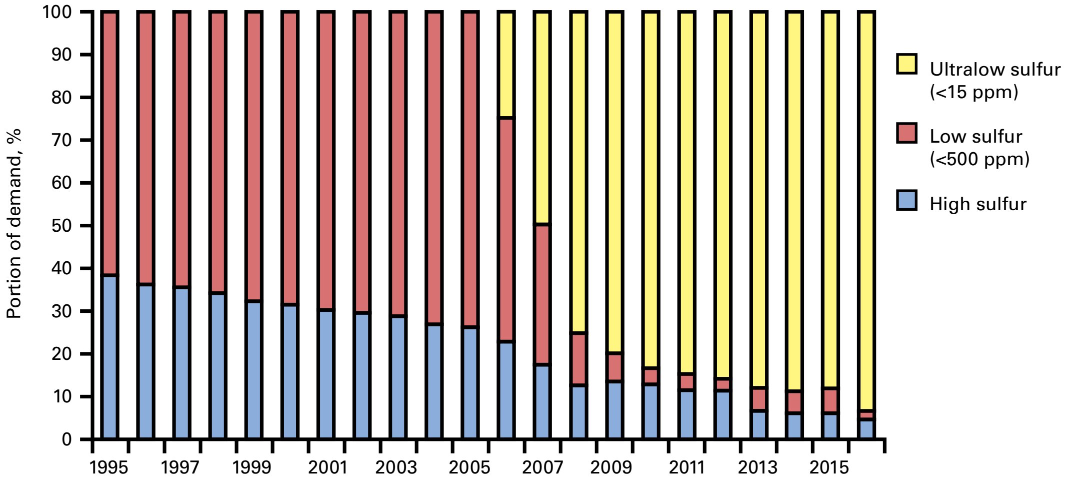
The unit, according to designer Black & Veatch, Overland Park, Kan., is the first to pair "two existing and proven technologies in a way that guarantees removal of 99.9% of sulfur from a refinery's acid gases."

The new complex (photo) uses a first-of-its-kind configuration consisting of three sub-dewpoint cold bed adsorption sulfur trains connected to a conventional, amine-based tail-gas treating unit.

Total processing capacity for the new tail-gas treating unit is 2,025 tonnes/day, doubling sulfur processing capacity at the Jamnagar refining complex to 4,050 tpd. Total processing capacity at the Jamnagar export refinery is 1.2 million b/d of a wide variety of crudes ranging from sweet to heavy, with sulfur content up to 4.5 wt %.

DIESEL SULFUR

Fig. 4



probably initially to moderate levels then to ultralow sulfur levels.

A group of Northeast states has been active in considering the issue and have conducted studies. The general proposal includes a reduction in heating-oil sulfur to 500 ppm followed later to 15 ppm. The legislative action appears imminent enough that the New York Mercantile Exchange has stated it will not list heating-oil futures contracts past August 2012, pending New York and New Jersey's sulfur-reduction proposals.

As Fig. 4 shows, these factors, along with expected spillover of lower-sulfur fuels into high-sulfur consumption sectors, will result in the high-sulfur demand share falling with the 15-ppm product growing rapidly through 2015. Fig. 4 assumes domestic marine and railroad move to 15 ppm in 2012 and heating oil in key Northeast states is reduced to 500 ppm in 2013 and 15 ppm in 2016.

Bunker fuels

The most significant change in refinery fuels' sulfur content comes from the bunker markets. The International Maritime Organization has put forth changes that will affect refinery production of hard-to-refine residual bunker fuels. These changes are discussed presently and the subject of a new study.[1] That study addresses the global and regional bunker markets in the context of the broader residual fuel and refining market.

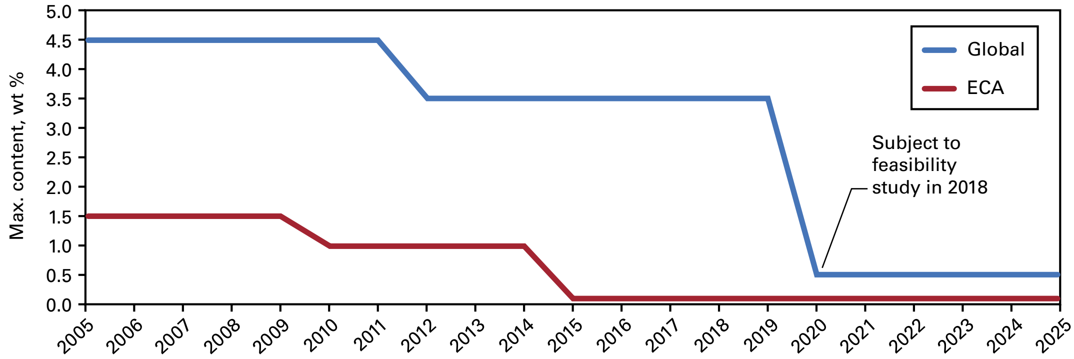
Since 1970, the IMO has controlled and sought to reduce the environmental impact from international shipping. The pollution program comes under the International Convention on the Reduction of Pollution from Ships (MARPOL).

This treaty's impact on shipping over the past decades has focused on reducing ship pollution of oily waste, bilge-water disposal, tank cleaning emissions, and the like. Annex IV of the MARPOL 73/78 treaty includes the "Regulations for the Prevention of Air Pollution from Ships" and was finally ratified and put into force in 2004.

From May 2005 it became a requirement to comply with all the regulations of the new Annex VI including the use of fuel with sulfur content no higher than 4.5% and the requirement to provide a "Bunker delivery note" (BDN) with details of the sulfur content and density

Sulfur in marine bunker fuel

Fig. 5



of the fuel delivered.

Subsequently, major amendments to Annex IV were ratified in October 2008 that will dramatically impact the refining and shipping industries. The amendments call for the reduction of sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matters (PM) from ships. The sulfur reduction will have the greatest impact on refining but the shipping industry will need to address the other emissions limits as well.

Separately, there are discussions on ways to reduce ship's CO_2 emissions, but no formal action has been proposed as of this writing. The amendments call for reductions in two geographic areas:

1. Emissions control areas (ECA or originally SECA for SOx Emissions Control Area).
2. The rest of the globe.

Emissions reductions in ECAs are more immediate and severe with the global requirement coming later. ECAs can specify regulations of SOx, NOx, PM, or a combination. Environmental justification is necessary for the IMO to agree to an ECA adoption. There are two SOx ECAs (SECAs) today, one in the Baltic Sea and the other covering the North Sea-English Channel.

Annex VI calls for substantial reduction in sulfur levels in the ECA and in the broader global market, as illustrated in Fig. 5.

Currently, the ECA requirement specifies that bunker fuel with a maximum sulfur of 1.5% be consumed in the ECA. The sulfur level is reduced to 1.0% in 2010 and 0.1% in 2015. Outside the ECAs, the bunker-sulfur limit is reduced to a maximum of 3.5% in 2012 and to 0.5% in 2020, subject to a study on the supply availability in 2018 that could result in the deadline being moved to 2025.

The US Senate ratified the IMO Annex VI treaty following the new amendments added last year. The EPA along with Canada has submitted a proposal for an ECA (SOx, PM, and NOx) that would essentially extended 200 miles off both coast lines and Hawaii. If approved by the IMO's Marine Environmental Protection Committee, expected to be voted on at a March 2010 meeting, the ECA could come into force around 2012.

Mexico has stated it will also seek an ECA soon. California has advanced separate regulations and issued a Marine Notice that only distillate fuels can be used within 24 nautical miles of its shore from July 2009.

Both the IMO Annex VI and the EPA proposed regulations allow for "Equivalents" technologies to be used in lieu of low-sulfur fuels. This opens the possibility that a seawater or closed water/caustic "scrubbing" approach or other technology could be employed.

While this technology is proven commercially in a number of onshore facilities, the application aboard operating vessels is mostly in a pilot-testing stage at present. The pilot results generally appear favorable and Wartsila, a marine engine manufacturer, has recently received a compliance certificate on its scrubbing technology for use in SOx ECAs.[2]

US bunker market

The bunker market is just part of the greater residual fuel oil and feedstock markets. The total US residual fuel market as defined in Fig. 6 is about 1.35 million b/d, of which more than half consists of refinery feedstocks including vacuum gas oil and straight-run residues.

The bunker market (international plus domestic supplies) varies from year-to-year, averaging about 400,000 b/d over the past 5 years. High-sulfur residual bunker fuel (Fig. 6) for 2008 was 415,000 b/d, not including another 125,000 b/d of marine distillates.

While demand for ECA fuels varies by coastal Petroleum Administration for Defense District (PADD), Purvin & Gertz's analysis of the US vessel port calls, routing of trade goods, and bunker supplied concludes that a sizable portion of the bunker supplied is consumed in the proposed ECA area.

The most immediate question facing US refiners on this topic is how this ECA requirement affects demand and the type of fuel required. Our work supports the idea that nearly all of this demand shifts to distillate fuels by 2015, based on two key factors.

First, the timing of the regulation and the status of the ship-scrubbing technology will probably not allow for a significant number of scrubbers to be installed on the vast number of vessels that call on US ports.

Second, the scrubbing economics are not supported on a vessel that only spends a limited portion of a global voyage in an ECA, based on Purvin & Gertz's forecast. Even a vessel sailing from the Northwest Europe ECA and into the North American ECA would only utilize a scrubber about 20% of the voyage. Most vessels will spend much less time in the ECA area, even multiport container vessels.

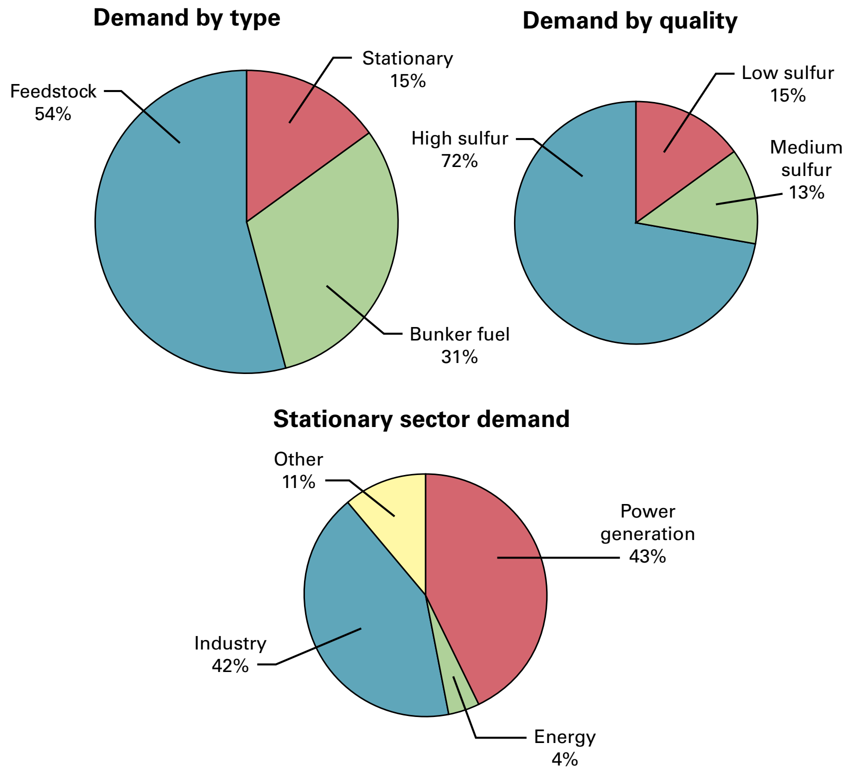
Therefore, we predict that marine distillate-type fuels will replace a sizable portion of the high-sulfur residual bunkers supplied in the US in 2015. By the time the global bunker requirements come into force, scrubbing technology and its possible implementation could change the dynamics.

Scrubbing economics on large and medium-sized oceangoing vessels appear attractive in our analysis and could mitigate the fuel-quality changes required once the global requirements take effect. There are some important technological and environmental-related hurdles to overcome. Our study considers two very different outcomes in separate Scrubber Compliance and Fuels Compliance Scenarios.

One thing is clear from our analysis: Shifting ships to low-sulfur fuels affects both the residual fuel and diesel/gas-oil markets because some portion of the shipping industry will shift fuel type, even with aggressive scrubber adoption.

US RESIDUAL FUEL MARKET

Fig. 6



Refining impact

The net result of these quality changes calls for more and higher quality distillate fuels. Additional sectors of the US diesel market will move towards ultralow sulfur levels. Jet-fuel sulfur may eventually be lowered. Most importantly, the marine-fuels markets are going to require more distillate volume as replacements for traditional residual bunker fuels.

None of these changes is immediate and most are 5 years or so from coming into effect. This gives refining and shipping companies time to plan for the changes.

Bunker fuel has traditionally been a low-value product and even considered a by-product. Most refiners may find it difficult to envision investing for bunker-fuels manufacturing, but this is a reality facing the industry.

The changes create both opportunity and risk for refiners. Acting quickly and boldly to produce higher quality marine fuels could be rewarding but might also create stranded investments if bunker markets shift in unanticipated ways.

The shipping industry is facing its own strategic and investment decisions. The complex inter-industry issue calls for more coordination and discussion between refining and shipping industries.

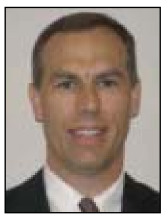
These changes will not aid refiners today that are struggling with chronic overcapacity and dismal refining margins. However, they should help improve longer-term profitability for those assets that are well placed to supply these fuels on a cost effective basis. ✦

References

1. "Residual Fuel Market Outlook: Impact of Bunker Quality Changes on Marine Fuels and Refining," Purvin & Gertz, October 2009.

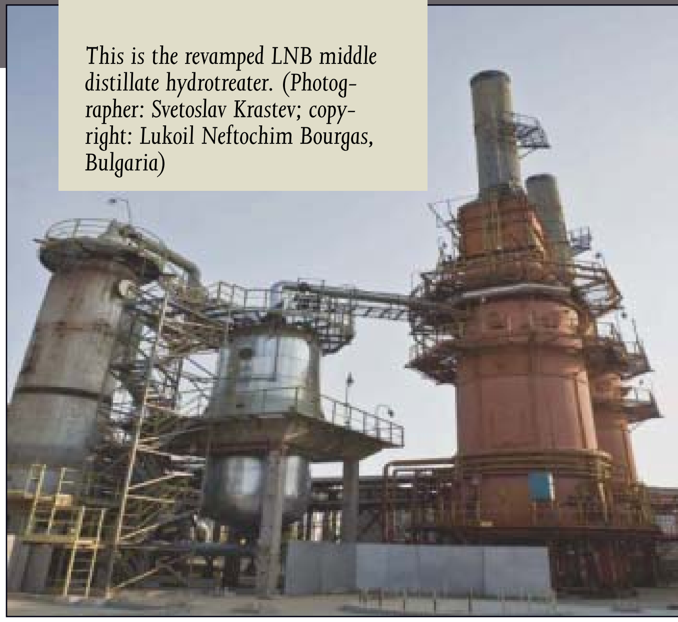
2. "Wartsila scrubbers first to be certified to combat marine sulphur oxide emissions," company press release, Sept. 10, 2009.

The author



Kurt A. Barrow (kubarrow @PurvinGertz.xom) is a vice-president for Purvin & Gertz Inc., Houston. Before joining Purvin & Gertz's Houston office in 1997, he was employed at the ExxonMobil Baytown, Tex., refinery. In 2001, he transferred to the Purvin & Gertz Singapore office. In 2007, Barrow moved back to the Houston headquarters office of Purvin & Gertz. He holds a bachelor's degree in mechanical engineering from Kansas State University and an MBA from the University of Houston. He is a member of the American Society of Mechanical Engineers.

Image from CB&I's Virtual Refinery



This is the revamped LNB middle distillate hydrotreater. (Photographer: Svetoslav Krastev; copyright: Lukoil Neftochim Bourgas, Bulgaria)

Poor hydrotreater reliability can reduce ULSD production

Dicho Stratiev
Lukoil Neftochim Bulgaria
Bourgas, Bulgaria

This article reports on the investigation of low production of ultralow sulfur diesel (ULSD) at a middle distillate hydrotreating unit in the Lukoil Neftochim Bulgaria (LNB) refinery, in Bourgas, Bulgaria. Specifically, it focuses on problems arising from unreliable operation of the unit's heat exchangers.

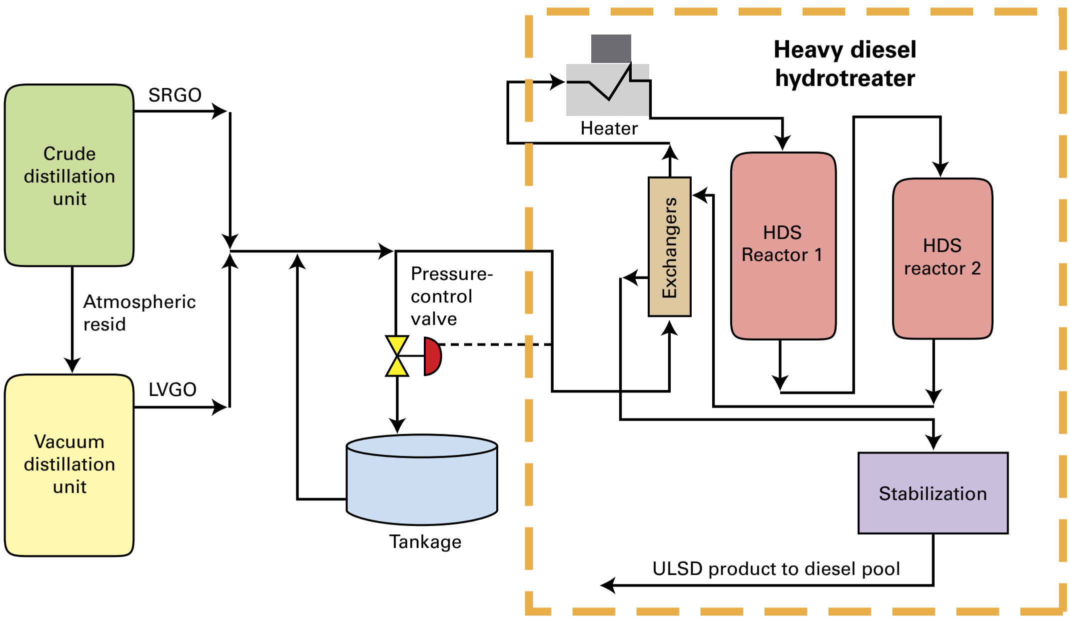
The investigation reached two main conclusions:

1. A failure in the reliable operation of the heat exchanging equipment of a middle distillate hydrotreater can lead to a failure in the production of ultralow sulfur diesel and near-zero sulfur diesel.

2. The most reliable information proving the presence of a leak in a middle distillate hydrotreater heat exchangers is gas chromatography—atomic emission detector (GC-AED) analyses of the feed and product sulfur compound distribution. The presence of benzothiophenes in the product from the hydrodesulfurization (HDS) unit to as high as 99% would indicate a leak in the heat exchanging equipment.

FEED CHARGE TO LNB HYDROTREATING UNIT

Fig. 1



Background

After extensive pilot plant tests in 2005 lasting 6 months, the Topsoe TK-576 Brim was selected in July 2005 as the best catalyst for this hydrotreater. During a cycle time lasting 11 months, the unit performed unsatisfactorily, prompting several tests to determine the reason for the poor performance.

The sulfur level in the hydrogenate varied in the range 40-80 ppm and operators observed no dependence of the weighted average bed temperature (WABT) on the product sulfur. Two possible reasons were a catalyst bypass or heat exchanger block leakage.

Tests with different liquid hourly space velocities (LHSV) showed good response of product sulfur vs. LHSV that indicated no problems with catalyst bypassing. Therefore, leakage in the heat exchanger block appeared to be why the hydrotreater performed poorly.

Analyses of the product sulfur by GC-AED revealed the presence of benzothiophenes, a highly reactive sulfur species that should not have been present in the product at this high desulfurization rate (higher than 99%). After shutdown of the unit, investigators discovered a crack in the compensator of one of the six heat exchangers utilizing the heat of reaction products for preheating the hydrotreater unit's feed.

After that heat exchanger was repaired and the middle distillate hydrotreating unit placed on stream, the unit was able to produce lower than 40-ppm sulfur at maximum capacity.

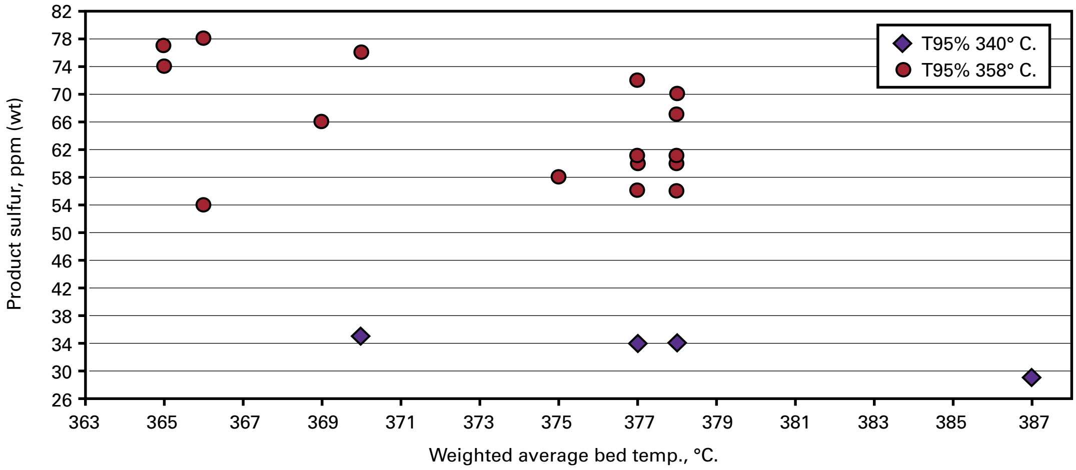
Catalyst selection

Successful production of ultralow and near-zero sulfur diesel requires a proper catalyst selection, a modern reactor distribution tray that guarantees even distribution of feed and hydrogen across the catalyst bed, and reliable hydrotreater equipment operation.

Failure of one of these areas can lead to failure in the production of ULSD and NZSD. The LNB refinery had

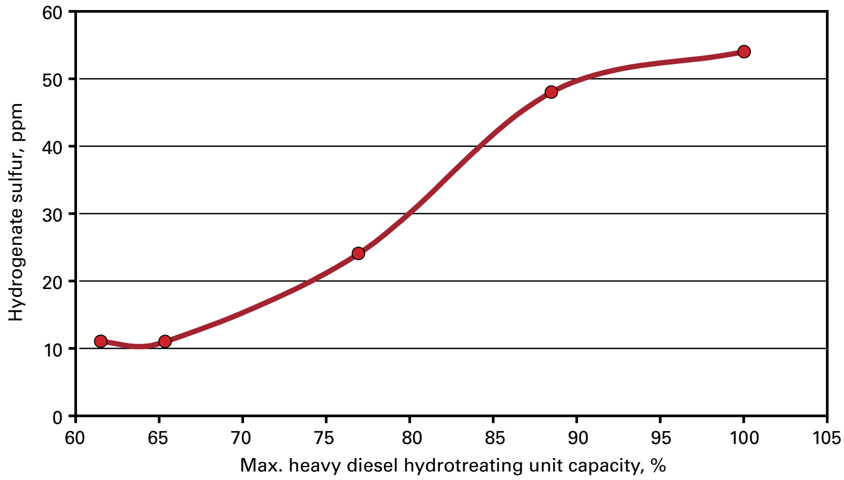
Unit test runs at LHSV 1.49 h^{-1}

Fig. 2



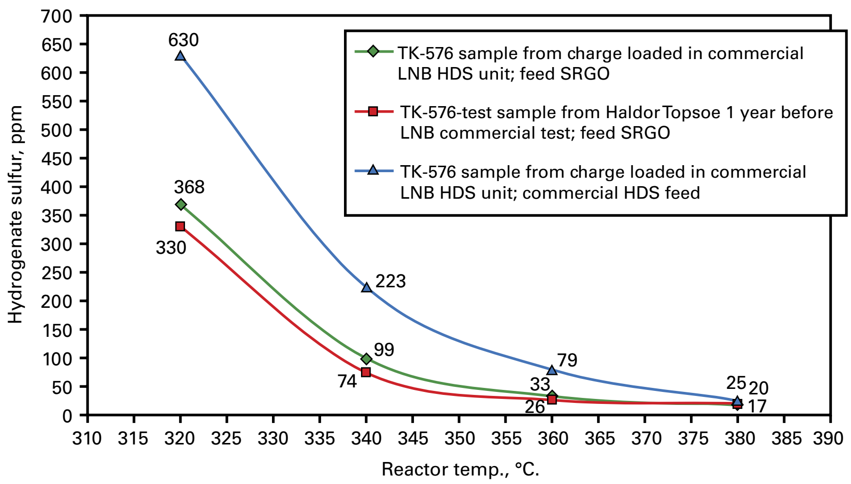
Processing SRGO, LVGO blend

Fig. 3



Pilot results at LHSV 1.5 hr^{-1}

Fig. 4



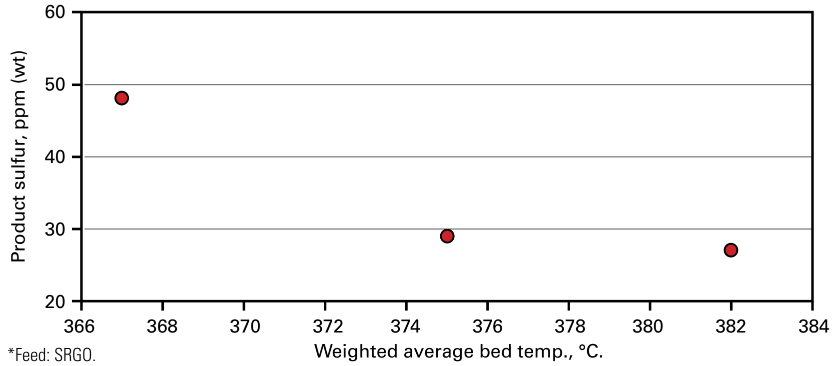
HYDROTREATING STUDY

Table 1

Process parameter	
LHSV, hr^{-1}	1.0-1.7
Total reactor pressure, MPa	3.4
H_2/oil, cu m/cu m	250
H_2 content in treating gas, vol %	83
Reactor inlet temperature, °C.	340-380
ΔT of reaction, °C.	12-17
Feed sulfur, %	0.8-1.1

TEST AT LHSV 1.49 HR^{-1}*

Fig. 5



*Feed: SRGO.

prepared for production of ULSD by implementing extensive pilot tests to select the most appropriate catalyst to hydrotreat the available middle distillate fractions to ultra low and near zero sulfur level.[1 2] The result of this program was selection of the Haldor Topsoe TK-576 Brim catalyst.

After catalyst selection, the modern Topsoe vapor-lift-tube distribution tray was installed in one LNB's middle distillate hydrotreater. This unit hydrotreated the most refractory heavy diesel fraction, which was a blend of heavy straight-run gas oil (SRGO) and light-vacuum gas oil (LVGO) from Urals crude.

Two of the requirements for the successful production of ULSD were fulfilled; the remaining requirement was reliable operation of the equipment in the heavy diesel hydrotreater.

The aim of this article is to discuss the influence of the reliable operation of the heat exchanging equipment on the production of ULSD.

CHARACTERISTICS OF DIESEL FRACTIONS

Table 2

	Feeds			
Index	SRGO	LVGO	Commercial hydrotreater feed	35% LVGO 65% SRGO (calculated properties)
Sulfur, %	0.8727	1.3108	1.0171	1.026
Sulfur, type				
Benzothiophenes, %	33	22	28	
Dibenzothiophenes, %	66	78	72	71.4
Total nitrogen, ppm	135	274	183	184
Basic nitrogen, ppm	56	101	70	
Specific gravity	0.8576	0.8868	0.8615	0.8619
Arenes, %				
1 Ring	17.57	20.34	19.18	
2 Ring	8.67	12.37	9.43	
3+ Ring	1.44	3.34	1.86	
Cetane Index,				
ASTM D 4337	54.3	47.8	54.2	
Simulated distillation, °C.				
0.5 wt % (IBP)	176	198	128.5	
5 wt %	233	253	224.5	
10 wt %	249.5	271	250.5	
15 wt %	259.5	285	265	
20 wt %	268	294.5	274.5	
30 wt %	283	308	292	
40 wt %	296	319.5	304.5	
50 wt %	306.5	330.5	317	
60 wt %	319	341.5	328	
70 wt %	332	352.5	341	
80 wt %	347.5	366	355.5	
85 wt %	357	374	364	
90 wt %	368	385.5	374.5	
95 wt %	384.5	404	390.5	
99.5% (FBP)	431.5	459	431.5	
Calc. ASTM D86, °C.				
0.5 vol %				
5.0 vol %	254.8	276.4	255.6	
10% vol	265.6	288.2	268.4	
20 vol %	278.4	302.6	284.8	
30 vol %	286.8	311.4	295.2	
50 vol %	301.6	325	311.6	
70 vol %	319.4	338.4	327.6	
80 vol %	328.8	345.6	336.8	
90 vol %	346.6	363.4	352.6	
99.5 vol %	376.2	397	379.4	

Pilot testing

Following the loading of the TK-576 Brim catalyst charge into both hydrotreating reactors of the LNB heavy diesel hydrotreater and some adjustment of the operation, a performance test was carried out. Table 1 summarizes the operating conditions of the hydrotreater under study.

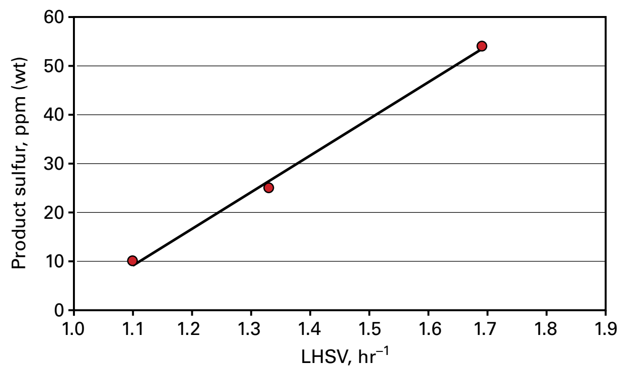
Fig. 1 presents a simplified diagram of feed charging to the heavy diesel hydrotreater, the reactors, and available sampling points for process control. Fig. 2 presents the results of this test.

The data in Fig. 2 show that the sulfur in the product fluctuated in a wide range (40-80 ppm) with no dependence of hydrogenate sulfur on reactor temperature found. Sulfur hydrogenate was falling to less than 50 ppm, when 95% distillation point was reduced to 340° C. from 355° C. or when feed charging was reduced by 10% (Fig. 3).

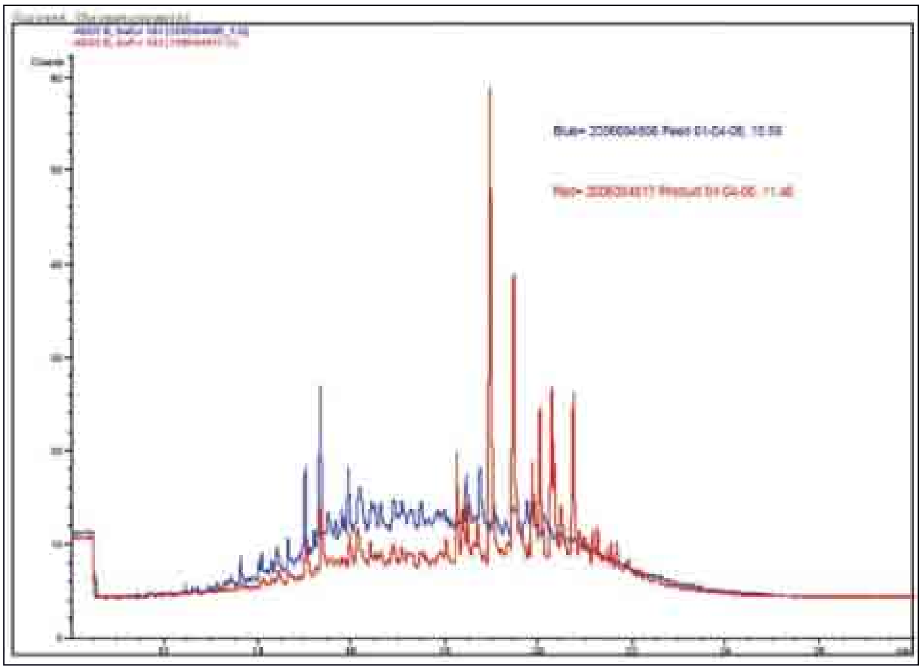
The need to explain this unsatisfactory operation of this heavy diesel hydrotreater prompted tests in the LNB

PROCESSING SRGO AT CONSTANT WABT OF 366° C.

Fig. 6



This is a chromatogram of sulfur specification of the LNB heavy diesel hydrotreating unit feed and product obtained during testing with SRGO feed (Fig. 7).



Research Laboratory pilot unit. The pilot plant's operating test conditions were identical with those of the commercial unit.

Two catalyst samples were examined: the TK-576 Brim test sample, provided by Haldor Topsoe a year before the catalyst commercial application, and the TK-576 Brim catalyst sample from the charge loaded in the commercial unit reactors.

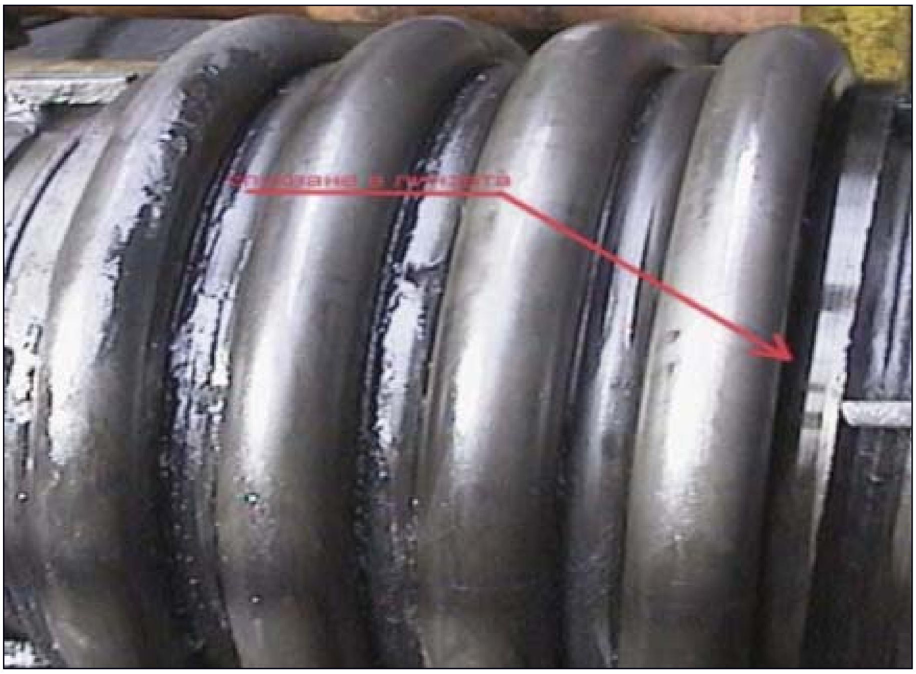
Two feeds of straight-run gas oil SRGO 240-360° C. from the crude distillation unit and the hydrotreater feed (blend of SRGO 240-360° C. and LVGO) were tested. Table 2 presents the properties of SRGO 240-36° C., LVGO, and the commercial hydrotreater feed. Considering the content of total sulfur, nitrogen, and dibenzotiophenes in SRGO from crude unit and LVGO allows calculation that LVGO in the commercial hydrotreater feed was 35%.

The refinery operating data, however, indicated that this hydrotreater feed LVGO content should have been no higher than 10%. This discrepancy could be explained by the scheme of charging feed to the heavy diesel hydrotreater, i.e. blend of SRGO and LVGO plus a certain amount from tank farm (Fig. 1).

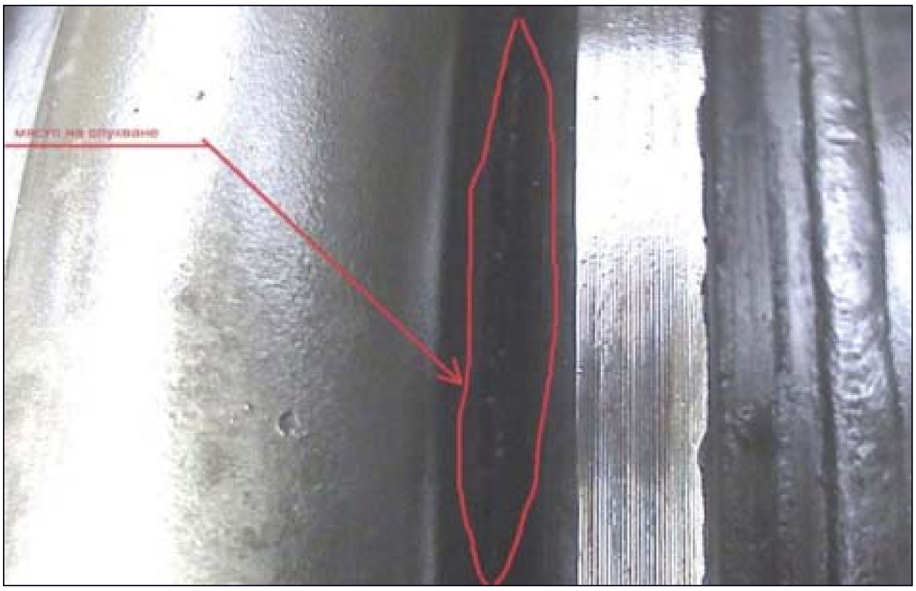
Fig. 4 (pilot plant test results) indicates that the catalyst TK-576 Brim quality from test sample and from reactor charge was identical. The observed deviations between sulfur content in hydrogenate from both catalyst samples in HDS of SRGO were within the repeatability of the method used for sulfur determination in this study, ASTM D-3120 (repeatability of 28%).

Fig. 4 also shows that feed quality has considerable effect on hydrogenate sulfur. For example, the 50-ppm sulfur level in hydrogenate was achieved at WABT of 355° C. when the SRGO was treated, while WABT of 367° C. was required to reach the same product sulfur level when the commercial feed

The red arrow indicates in which heat exchanger body a leak was detected (Fig. 8).



The red arrow indicates the crack in the heat exchanger's compensator (Fig. 9).



The red circle indicates the heat exchanger compensator crack (Fig. 10).

was treated. These results suggested that the most probable reason for the unsatisfactory operation of the heavy diesel hydrotreater was the frequent fluctuation of feed quality, which was due to different ratio between SRGO and LVGO.

Cause found

In order to check this hypothesis, researchers discontinued the LVGO processing in the heavy middle distillate hydrotreating unit and conducted another test with SRGO as the only feed for the unit. Fig. 5 presents the results from the second test with feed SRGO at constant throughput and different reactor temperatures.

These data again did not indicate clear dependency of hydrogenate sulfur on reactor temperature. The reason for these results could be the bypass of catalyst bed in reactors or leakage and mixing of feed with product in heat exchangers. Fig. 6 illustrates dependency of hydrogenate sulfur from LHSV at constant WABT of 365° C. These data show that hydrogenate sulfur fell with a reduction of LHSV.

This refuted the hypothesis of the catalyst bed bypass. In case of bypass, the reduction of LHSV would not cause sulfur reduction in the product. Analysis of feed and product, made during the test showed presence of benzotiophenes in hydrogenate (Fig. 7). These benzotiophenes are 20 times as reactive as substituted dibenzotiophenes and should not be present in hydrogenate at sulfur levels of 40-80 ppm.

These facts indicated the most probable reason for unsatisfactory operation of the heavy diesel hydrotreater was a leakage in heat exchanger block after reactors where feed is heated by hydrotreated product. Shutdown of the unit and opening of heat exchanger block revealed that there was a leak in one of the six heat exchanger bodies (Fig. 8). A crack in the compensator of the heat exchanger body was detected (Figs. 9-10).

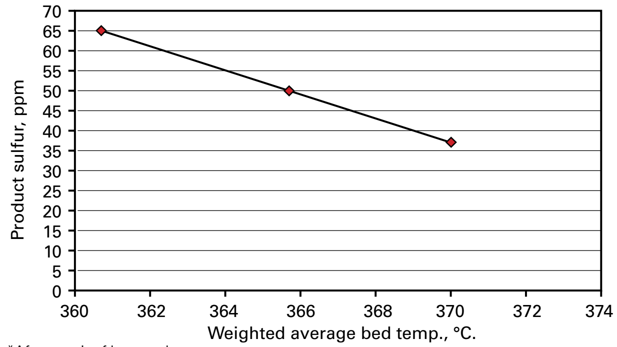
This finding gave reasonable explanation of observed strange results. Obviously the extent of leakage has been changing during the unit's operation because the place of the detected crack should allow opening and closing depending on pressure and temperature changes in the heat exchanger.

After repair of that heat exchanger, the reactors of the heavy diesel hydrotreater were charged with fresh TK-576 Brim catalyst and the unit returned to operation. A test was performed with the typical feed for this unit, a blend of SRGO and LVGO. Results of this test (Fig. 11) showed that hydrogenate sulfur continuously dropped with increased WABT. Hydrogenate sulfur achieved 50 ppm at WABT 365° C., which was impossible during the first cycle of catalyst TK-576 BRIM.

It was obvious that in this heavy

PROCESSING BLEND SRGO/LVGO AT LNSV 1.7 HR^{-1}*

Fig. 11



*After repair of heat exchanger.

diesel hydrotreating unit, it was impossible to get 10 ppm sulfur in hydrogenate at maximum capacity with this feed and these operating conditions. The unit was therefore revamped at the end of 2008 and the catalyst volume increased by a factor of 1.9. The heat exchangers were replaced by new ones in order to avoid any possibility of a leakage.

The result of this revamp was production of less than 10 ppm sulfur diesel (NZSD) and a reduction of furnace fuel by 50%. ✦

References

1. Stratiev, D., Galkin, V., and Stanulov, K., "Study: Most-active catalyst improves ULSD economics," OGJ, Aug. 14, 2006, p. 53.

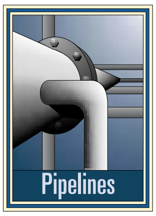
2. Dobrev, D., Stratiev, D., Argirov, G., Tzingov, T., and Ivanov, A., "Investigation on middle distillates ultra low hydrodesulphurization at Lukoil Neftochim Bourgas," Oxidation Communication, Vol. 30, No. 3, 2007, pp. 668-677.

The author

Dicho Stratiev (Stratiev.Dicho@neftochin.bg) is the research manager for Lukoil Neftochim Bourgas, Bourgas, Bulgaria. He joined Lukoil Neftochim Bourgas in 1990 as a process engineer in the catalysis laboratory in Lukoil's Research Institute for Oil Refining and Petrochemistry. During his 18 years with Lukoil Neftochim, he has been a process engineer on the visbreaker, vacuum distillation, and FCC units. Stratiev holds an MS in organic chemistry engineering and a PhD in petroleum refining from Bourgas University.

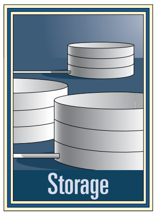
Study places CO_2 capture cost between $34 and $61/ton

Hitesh Mohan
Khosrow Biglarbigi
Marshall Carolus
INTEK Inc.
Arlington, Va.



Technologies in development for capturing CO_2 have an estimated cost between $34 and $61/ton of CO_2 captured, with specific costs both site and technology specific. Partnerships with enhanced oil and gas production projects, however, or the sale of pure CO_2 for industrial and commercial uses can yield values of up to $86/ton of CO_2 captured, transported, and sold.

This article will discuss examples of the various CO_2 capture technologies. It also discusses different industrial sources and options for industrial use of CO_2 as well as the various geological media suitable for sequestration. It will also provide estimates of CO_2 pipeline transportation costs at different source-to-sink distances.



The article will conclude with a discussion of the total cost at which captured CO_2 can be sold to operators of enhanced oil recovery projects or other industries capable of using it, determining CO_2 can be captured and transported up to 100 miles for prices between $1.00 and $3.00/Mcf.

Based on presentation to the Oil Sands and Heavy Oil Technologies Conference, July 14-16, 2009, Calgary.

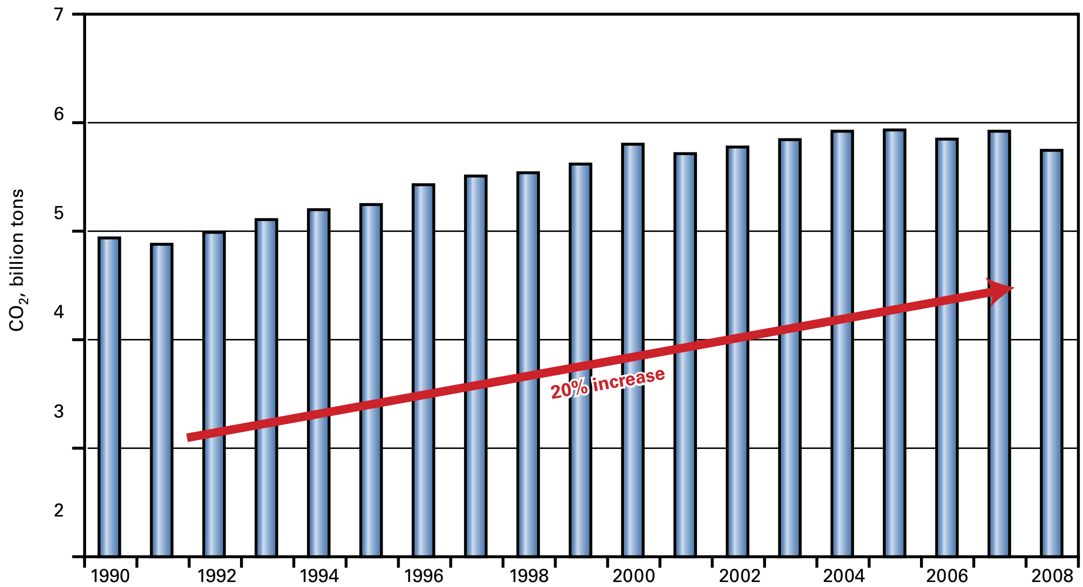
Background

To date CO_2 is the largest single contributor to the greenhouse-gas buildup in the atmosphere. The US Energy Information Administration reported the US emitted more than 5.75 billion tons of CO_2 in 2008,[1] an increase of more than 20% over 1990 emissions (Fig. 1). These factors have prompted a growing concern over greenhouse gas emissions from sources such as power generation, the number one source of CO_2 emissions worldwide.[2]

In order to help meet strict future environmental requirements, existing CCS technologies will be borrowed, enhanced, and reapplied. Sequestration can occur by either directly sequester-

US ANNUAL CARBON DIOXIDE EMISSIONS

Fig. 1



Source: US Energy Information Administration

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

ing the CO_2 or treating it as a commodity for a variety of industrial uses. Industrial sources of CO_2—the second largest annual source of greenhouse gas at 27%—are subject to capture and use. These CO_2 streams have food grade, industrial grade, and sequestration applications.

Capture technologies

As strict environmental, legal, and regulatory requirements are developed, CO_2 will need to be captured for sequestration or use in other industrial purposes. Amine absorption is one viable capture technology currently under development.

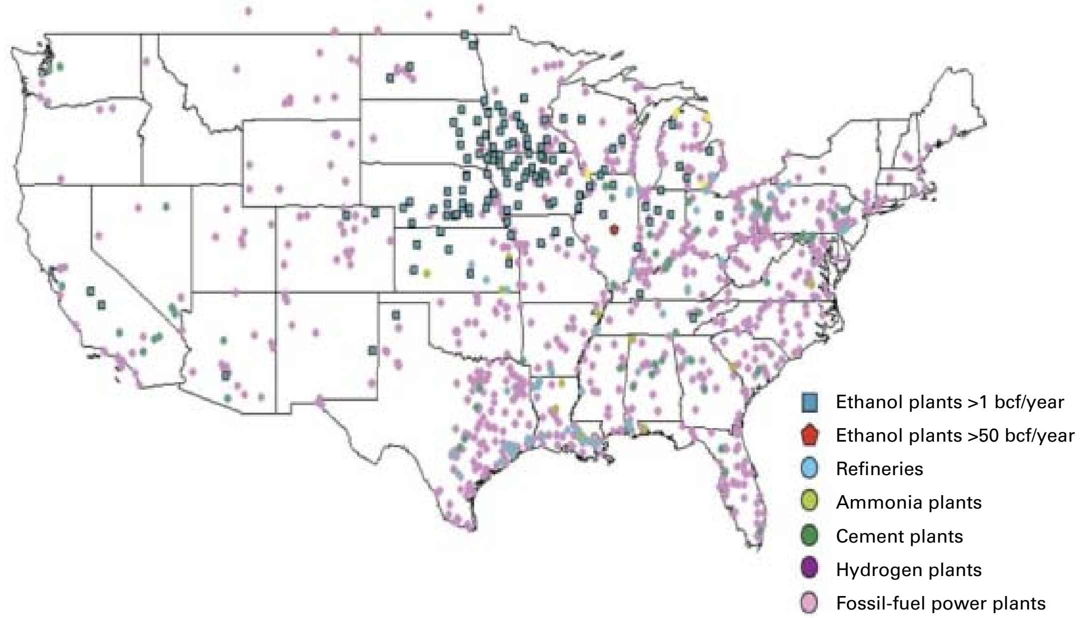
Aqueous monoethanolamine is a derivative of ammonia often used to treat flue gases. This process directs flue gases escaping from an industrial process through a cool aqueous amine solution, where the CO_2 reacts with the amine and forms a rich amine. Heating the rich amine releases the CO_2 for cooling and recycling. Drying the CO_2 removes the water vapor before compression for transport. Other capture processes under development include:

- Hot and cold methanol.
- Pressure swing absorption.
- Potassium carbonate.
- Membranes.
- Combinations of amine and membranes.

CO_2 capture costs depend on the process and the concentration of the CO_2 in the flue gas. The Intergovernmental Panel on Climate Change estimated in 2005 capture costs for CO_2 at between \$34 and \$61/tonne.[4] This cost includes both capital and operating costs and covers the capture, drying, and compression of CO_2.

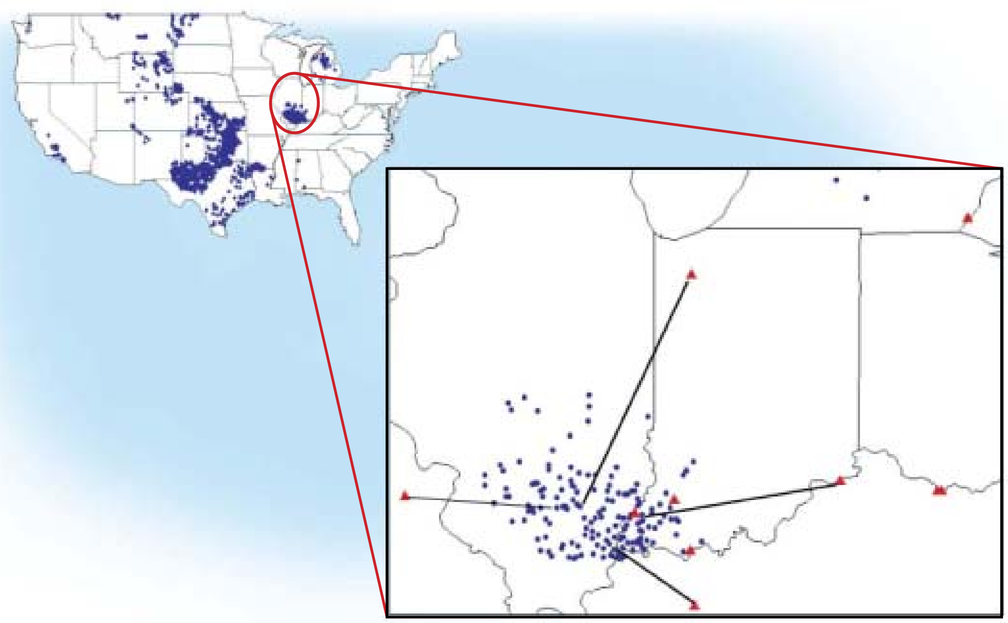
Industrial CO_2 sources

Fig. 2



Calculating average pipeline distances

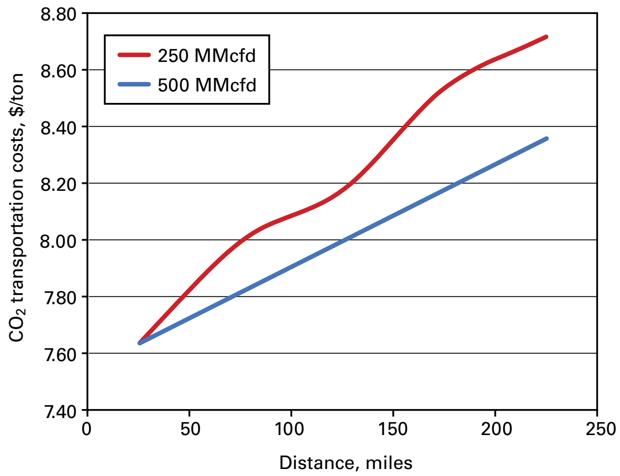
Fig. 3



Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page

Average pipeline tariffs

Fig. 4



Capture cost

Capture-cost data came from publicly available data including the Global Energy Technology Strategy Program Report.[4 9-11] Capture costs are technology-specific and vary drastically depending on plant type (Table 2). This article uses a cost estimate of between \$34 and \$61/ton of CO_2. These costs will likely decrease over time as the technologies become developed and expand market penetration.

Available industrial CO_2

Table 1

Industrial source	CO_2 available, bcf/year
Fossil-fuel plants	21,763
Refineries	2,082
Cement plants	403
Hydrogen plants	343
Ammonia plants	126
Ethanol plants	108
All	**24, 825**

Source-specific CO_2 capture costs

Table 2

Technology	$/ton
Fossil-fuel power plants	42-69
Refineries	39-61
Cement plants	39-61
Hydrogen plants	7-13
Ammonia plants	7-13
Ethanol plants	7-13
New integrated-gasification combined cycle plants	28-44

Industrial sources

The National Carbon Sequestration Database and Geographic Information System (NATCARB) served as the primary source of emission data for source-to-sink analysis. NATCARB is a unified database, funded by the National Energy Technology Laboratory and maintained by the Kansas Geological Survey. It contains several regional databases on carbon sources and sinks. INTEK analyzed these databases to provide unique subsets for analysis.[5]

The NATCARB database includes source data for industrial CO_2 emissions totaling 56.5 tcf/year. Data include utilities, ethanol, gas processing, concrete, steel, refineries, ammonia, and other industrial sources. Potential sources include fossil fuel plants, refineries, cement plants, hydrogen plants, ammonia plants, and ethanol plants. Fig. 2 maps the industrial sources considered in the study.[6]

Fossil fuel plants and refineries represent more than 90% of the capturable CO_2 emitted. Emissions from ethanol plants will grow steadily in the near future. Data from the Renewable Fuels Assocation supplemented the location and emission data of ethanol plants.[7] Capture from these industrial sources can provide up to 25 tcf/year of industrial CO_2 (Table 1).[8]

Transportation costs

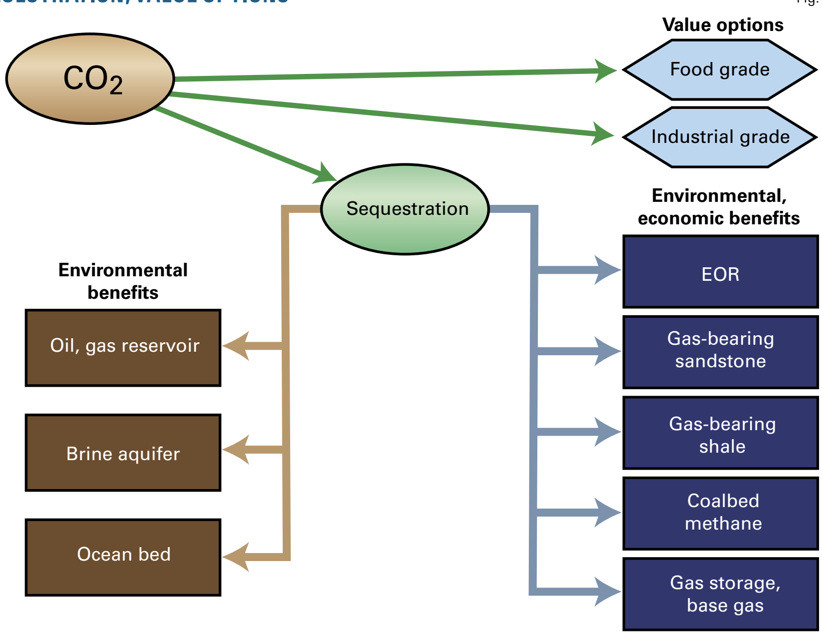
Truck, barge, ship, and pipelines can all transport CO_2. Transport via truck, barge, and ships moves CO_2 as a liquid, requiring liquefaction infrastructure and additional activities such as loading and unloading. Associated costs equal \$11/ton for liquefaction and \$1-11/ton for shipping.

CO_2 transported via pipeline must be dried and compressed (2,000-3,000 psig), at a combined cost of \$10/ton. Transportation costs consist of pipeline tariffs calculated using the following procedure:

- Overlaying maps of industrial sources and candidate fields.

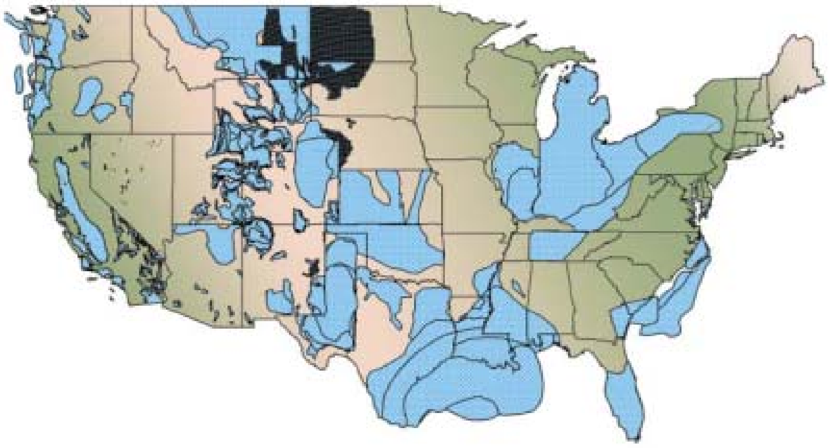
Sequestration, value options

Fig. 5



DEEP SALINE AQUIFERS

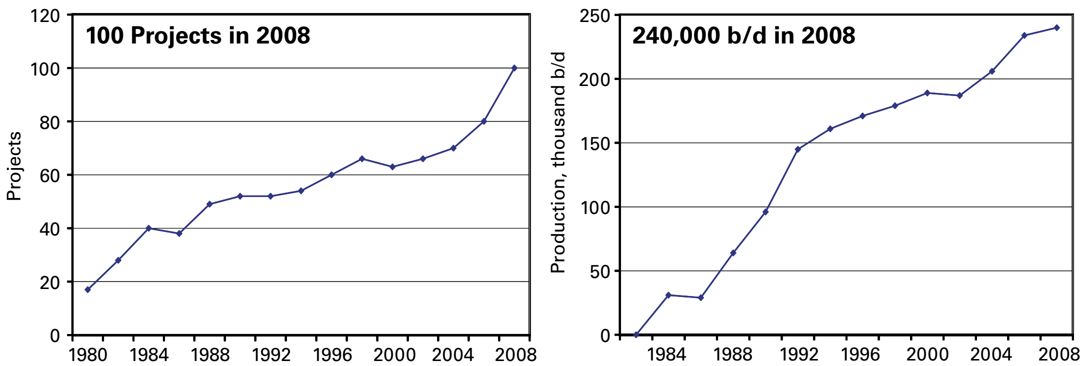
Fig. 6



Source: NatCarb

US CO_2 EOR PROJECTS

Fig. 7



- Calculating average distances between the sources and fields.
- Applying a minimum model-developed pipeline tariff rate for each source.

Fig. 3 shows the distances between four refineries and a large number of candidate fields in the Illinois basin. The tariff used would be for the average distance of 158 miles.

Pipeline cost depends on the distance the CO_2 is transported, the capacity of the pipeline, and the compression equipment required. Fig. 4 provides example costs for two pipeline scenarios, with transportation costs ranging from <\$8/ton to >\$9/ton depending on volume and distance of CO_2 transported.

Storage options

After the CO_2 has been captured compressed, and transported, it must be sequestered. A company can either directly sequester the CO_2 or treat it as a commodity for industrial use (Fig. 5). The CO_2's value depends on its level of contamination and the purpose for which it is intended. This section describes key sequestration and value options.

- *Depleted oil and gas reservoirs.* Carbon dioxide can be injected into depleted or abandoned reservoirs. The National Energy Technology Laboratory conducted a CO_2 sequestration pilot test in 2008 at the depleted West Pearl Queen field in New Mexico, injecting 2,100 tons of CO_2.[12]
- *Deep saline aquifers.* Another sequestration option uses saline aquifers, composed of porous rock containing brine. An extensive impenetrable rock layer caps these aquifers—widespread throughout the US and Canada—allowing trapping of the injected CO_2.[12]

Several aquifers with large storage potential lie in Utah, Wyoming, and Colorado, including the Farnham dome along the southwestern edge of the Uinta basin, the target site of a planned field test of the effectiveness of carbon sequestration in deep saline aquifers

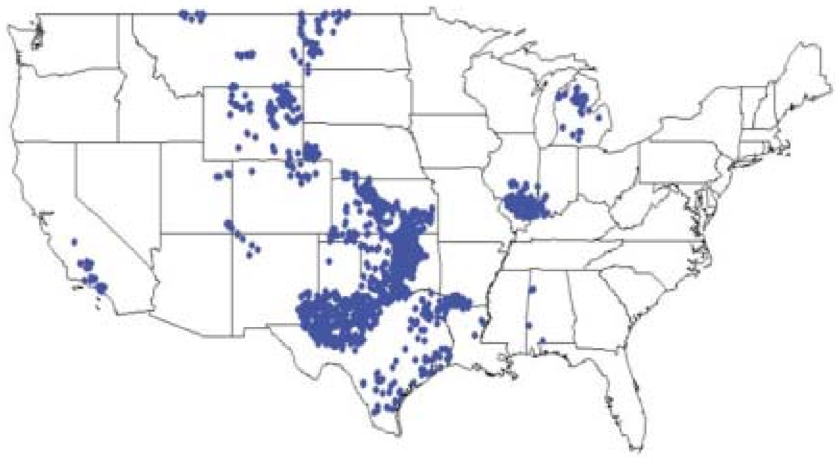
NETL reports injection wells will be drilled in 2009 and CO_2 injection will continue through 2012. Up to 1 million tons/year of CO_2 will enter the dome during the test phase, followed by several years of monitoring.

An NETL assessment of deep saline formations found a combined storage capacity of between 219 and 1,119 million tons of CO_2 in Colorado, Utah, and Wyoming.[12] Fig. 6 shows the locations of these saline aquifers.

- *Ocean beds.* Sequestration of CO_2 in the ocean bed is an experimental technology and is not currently in use. Under this option, if sequestration is occurring at up to 1,000 m water depth, it will be transported by pipeline; otherwise, a ship will be required.
- *Food and industrial-grade CO_2.* If a company purifies the CO_2 sufficiently, it can be sold as either industrial or food-grade. Preparing CO_2 for an industrial or food purpose is more costly than sequestration, however, as it must meet purity standards. Industrial CO_2 must be at least 99.5% pure, while the food grade CO_2 is required to be 99.9% pure.
- *Enhanced oil recovery.* CO_2 EOR technology has been profitable in commercial applications for nearly 30 years. As of 2008 there were 100 CO_2 EOR projects in the US, with a combined crude oil production of 240,000 b/d. Twenty of these projects started be-

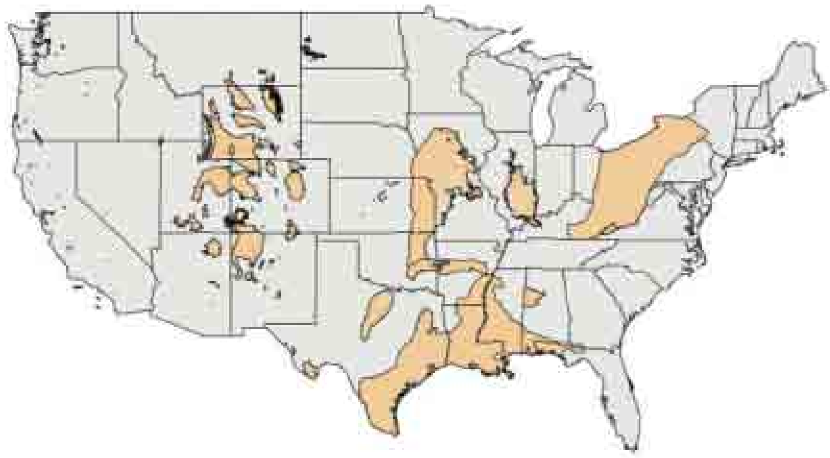
CANDIDATE US CO_2 EOR FIELDS

Fig. 8



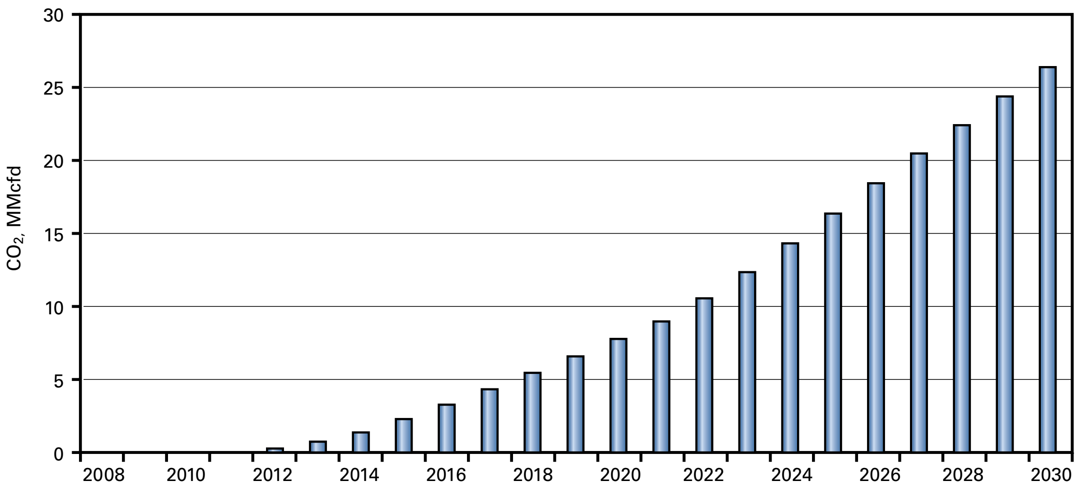
UNMINABLE COAL SEAMS

Fig. 9



EOR CO_2 SEQUESTRATION

Fig. 10



tween 2006 and 2008. Fig. 7 illustrates the relationship between the increase in the number of active projects and the increase in production (OGJ, Apr. 21, 2008, p. 42).

There are nearly 2,100 reservoirs in the onshore Lower 48 states that are candidates for CO_2 miscible flooding (Fig. 8) and would present a market for produced CO_2. Indentifying these potential reservoirs used the following criteria:

1. API gravity >22°.
2. Reservoir pressure greater than the minimum miscibility pressure.
3. Depth >2,500 ft.
4. Oil viscosity <10 cp.
5. Current oil saturation >20% of pore volume.
6. Sandstone or carbonate rock.

- *Gas bearing sandstone.* CO_2 injected into gas bearing sandstone can maintain pressure and produce the methane contained in the reservoir. Gas reservoirs in sandstones have ideal porosity for CO_2 injection. Injection is continued until the CO_2 breaks through. This process may require installation of additional injection wells and compressors to increase reservoir pressure.
- *Gas bearing shale.* CO_2 maintains reservoir pressure and produces methane through natural fractures in the reservoir. This process continues until CO_2 breaks through to the production well.
- *Coalbed methane.* CO_2 can also recover gas from unminable coal seams. Injecting CO_2 along with nitrogen into the coal seam allows production of methane and nitrogen, which is then separated. The nitrogen is reinjected into the seam while the methane is treated and sold. A pilot currently testing this process in the San Juan basin in

New Mexico[12] injects 35,000 tons/year of CO_2.

Fig. 9,[13] shows numerous unmineable coal seams in Utah, Wyoming, and Colorado near the oil shale deposits of the Green River basin. The National Energy Technology Laboratory estimates the storage capacity of coal seams in these three states at 21,283-22,142 million tons of CO_2.[12]

- *Gas storage.* CO_2 produced during oil shale development can also assist natural gas storage. Gas storage reservoirs provide support for seasonally driven natural gas demand: Gas is injected when demand is low and withdrawn when it's high. Since gas storage reservoirs use the pressure of the stored gas, a fraction of the natural gas cannot be withdrawn. Injected carbon dioxide can replace this base gas.

EOR application

As previously mentioned, about 2,100 reservoirs are candidates for CO_2 EOR. Many of these projects are economically viable with current or higher oil prices but are limited by the availability of CO_2. Widespread capture of industrial CO_2 for EOR could increase the available volume from 3 bcfd from natural sources to nearly 70 bcfd from natural and industrial sources.

A steady source of CO_2 in the US at prices of \$1.00-3.00/Mcf could help produce more than 200 CO_2 EOR projects with incremental production of nearly 1 million b/d. These projects would also provide the opportunity to sequester nearly 5 bcfd CO_2. Over 25 years, this could result in the production of more than 5.5 billion bbl of oil and the sequestration of nearly 30 tcf of CO_2 (Fig. 10).

EOR INCREMENTAL PRODUCTION Fig. 11

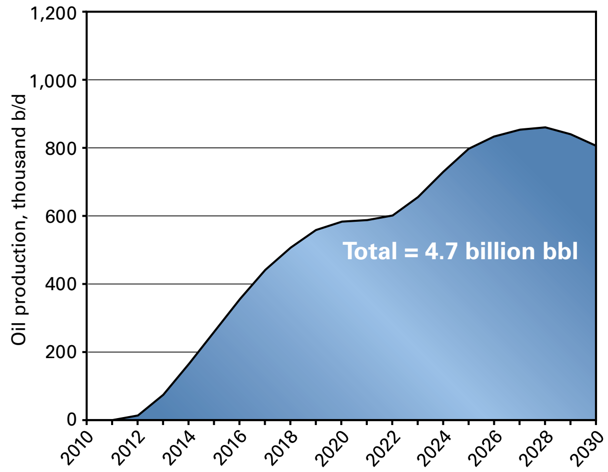


Fig. 11 shows incremental oil production from additional CO_2 projects through 2030. More than an additional 800,000 b/d incremental production could be realized, while sequestering nearly 5 bcfd CO_2. CO_2 sequestered is the difference between CO_2 injected and CO_2 produced. This assumes CO_2 from cheaper sources such as hydrogen and ammonia plants becomes available in 2015. Additional CO_2 from refineries and power plants becoming available after 2021 causes the two-hump shape of the CO_2 curve.

Costs, benefits

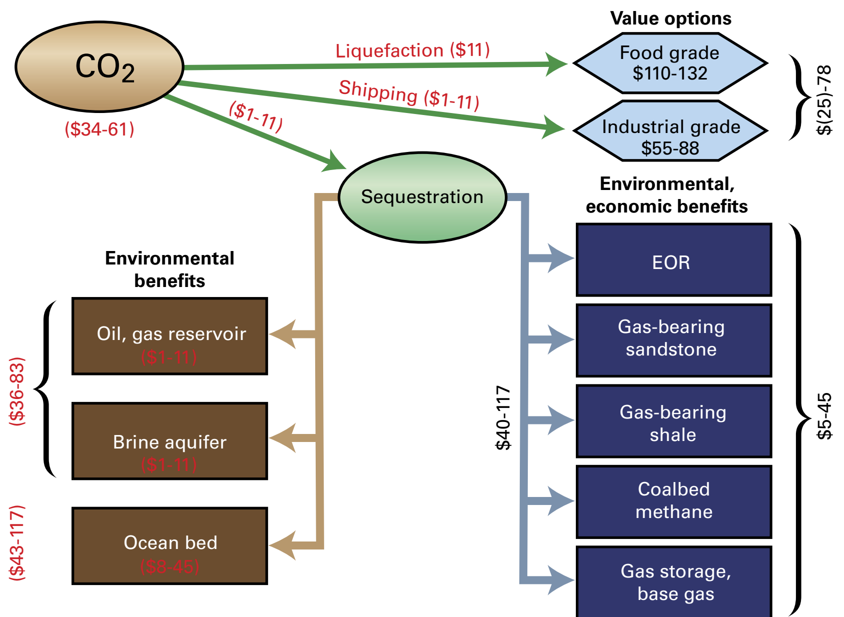
The total cost of carbon capture and storage includes the cost of capture, the cost of transportation, and the cost of either sequestering the CO_2 or the value that can be realized through its sale. Sequestration costs range from \$1/ton to \$45/ton, depending on the geologic media.

The cost of sequestering CO_2 in depleted oil and gas reservoirs and brine aquifers ranges from \$1 to \$11/ton depending on reservoir or aquifer depth. The additional technical difficulties of ocean bed sequestration raise its cost to \$8-45/ton. These costs include transportation of the CO_2.

The value of CO_2 sold for commercial or industrial use depends on the purpose of the CO_2. Values for industrial and food grade CO_2 can range between \$55 and \$132/ton. Values of CO_2 for enhanced oil or gas recovery can range between \$40 and \$117/ton. Fig. 12 shows sequestration costs and values.

Fig. 12 also provides the final costs and values of CO_2 inclusive of capture

COSTS, BENEFITS OF CO_2 CAPTURE AND SEQUESTRATION Fig. 12



Note: (Red) = cost, black = benefit.

and transportation. The capture costs are applied to all sequestration and value options. Food grade and industrial grade CO_2 also require liquefaction and transportation. Cost data for CO_2 used for enhanced oil and gas recovery or gas storage do not include transportation. The operator of the reservoir typically pays these costs.

The final cost of sequestration, including capture is $43-117/ton of CO_2, depending on the sequestration technology applied. Food-grade, industrial grade, and other value options are profitable, valued between $5 and $45/ton of CO_2 captured and sold. Costs do not reflect monitoring, liability, or other costs required by future regulations.

Acknowledgments

The authors thank the staff of INTEK Inc. for their efforts in preparing the manuscript and analysis, including Christopher Dean, Emily Knaus, and Jeffrey Stone. ✦

References

1. http://eia.doe.gov.
2. The National Petroleum Council, Reference Report #36: "Capturing the Gains from Carbon Capture," July 18, 2007.
3. UOP, "Amine Guard FS Process," 2000.
4. Metz, Bert, Davidson, Ogunlade, deConinck, Heleen, Loos, Manuela, and Meyer, editors, "Special Report on Carbon Dioxide Capture and Storage," Intergovernmental Panel on Climate Change (IPCC), 2005.
5. http://www.natcarb.org and INTEK, Inc., 2009.
6. http://www.natcarb.org and INTEK Inc., 2007.
7. http://www.ethanolrfa.org.
8. INTEK Inc., 2007.
9. Dooley, J.J., Dahowski, R.T., Davidson, C.L., Wise, M.A., Gupta, N., Kim, S.H., and Malone, E.L., "Carbon Dioxide Capture and Geologic Storage," Global Energy Technology Strategy Program, April 2006.
10. "The Cost of Carbon Dioxide Capture and Storage in Geological Formations," NETL/DOE, March 2005.
11. Dooley, J.J., Dahowski, R.T., Davidson, C.L., Wise, M.A., Gupta, N., Kim, S.H., and Malone, E.L., "Carbon Dioxide Capture and Geologic Storage," Global Energy Technology Strategy Program, April 2006.
12. Carbon Sequestration Atlas of the United States and Canada, Second Edition, National Energy Technology Laboratory, 2008.
13. http://www.natcarb.org.

The authors

Hitesh Mohan (hmohan@inteki.com) is vice-president and manager of petroleum engineering at INTEK Inc. in Arlington, Va. He has 20 years' experience in the petroleum and mining industries and in the evaluation of oil and gas resource potentials, recovery, petroleum exploration, energy economics, and public policy analysis. Mohan recently analyzed CO_2 capture and sequestration options and potential domestic production from widespread application of CO_2 EOR using CO_2 captured from industrial sources. He holds an MS in petroleum engineering from the University of Kansas and serves as section chairman of the National Capital Section of the Society of Petroleum Engineers.

Khosrow Biglarbigi (kbiglari@inteki.com) is president and director of petroleum engineering at INTEK Inc. in Arlington, Va. He has more than 25 years' experience in evaluating conventional and unconventional oil and gas resources, economic analysis, technology assessment, and evaluation of alternative policy options to encourage development of these resources. Biglarbigi holds an MS in petroleum engineering from the University of Tulsa.

Marshall Carolus (mcarolus@inteki.com) is an associate with INTEK Inc. He has 5 years' experience in data mining, statistical analysis, and development and application of oil and gas models to evaluate resource potential, recovery, and energy economics. He has earned a BS in mathematics from Villanova University and serves as the Young Professional coordinator of the National Capital Section of the Society of Petroleum Engineers.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	9-25 2009	9-18 2009	9-25 2009	9-18 2009	9-25 2009	9-18 2009	*9-26 2008
	1,000 b/d						
Total motor gasoline	833	1,028	18	0	851	1,028	1,261
Mo. gas. blending comp.	620	824	14	0	634	824	966
Distillate	87	157	63	28	150	185	195
Residual	276	173	101	0	377	173	375
Jet fuel-kerosine	51	49	64	74	115	123	145
Propane-propylene	136	71	6	8	142	79	243
Other	266	133	159	47	425	180	492
Total products	**2,269**	**2,435**	**425**	**157**	**2,694**	**2,592**	**3,677**
Total crude	**8,119**	**8,861**	**1,414**	**933**	**9,533**	**9,794**	**8,989**
Total imports	**10,388**	**11,296**	**1,839**	**1,090**	**12,227**	**12,386**	**12,666**

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

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center.

OGJ CRACK SPREAD

	*10-2-09	*10-3-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	72.66	108.03	–35.37	–32.7
Brent crude	65.84	94.63	–28.79	–30.4
Crack spread	6.82	13.40	–6.58	–49.1
FUTURES MARKET PRICES				
One month				
Product value	72.40	105.60	–33.20	–31.4
Light sweet crude	68.99	96.68	–27.69	–28.6
Crack spread	3.41	8.93	–5.51	–61.7
Six month				
Product value	78.22	110.18	–31.96	–29.0
Light sweet crude	71.32	96.92	–25.60	–26.4
Crack spread	6.90	13.26	–6.35	–47.9

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

PURVIN & GERTZ LNG NETBACKS—OCT. 2, 2009

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	5.74	4.11	4.95	4.01	4.29	4.88
Everett	3.88	1.88	3.53	1.97	2.40	4.16
Isle of Grain	3.15	1.18	2.57	1.08	1.69	2.59
Lake Charles	2.16	0.37	1.94	0.52	0.73	2.74
Sodegaura	4.86	7.11	5.12	6.81	6.05	4.23
Zeebrugge	5.26	3.59	4.92	3.49	4.17	4.94

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	15,248	55,556	37,221	12,715	75,042	13,980	4,355
PADD 2	77,658	50,022	24,431	7,984	33,094	969	31,024
PADD 3	177,510	71,326	39,288	15,766	47,913	14,809	34,803
PADD 4	14,963	6,375	2,029	547	3,261	229	[1]2,255
PADD 5	53,025	28,173	22,250	8,971	11,767	3,982	—
Sept. 25, 2009	**338,404**	**211,452**	**125,219**	**45,983**	**171,077**	**33,969**	**72,437**
Sept. 18, 2009	**335,608**	**213,109**	**127,198**	**46,199**	**170,754**	**32,635**	**72,026**
Sept. 26, 2008[2]	**294,464**	**179,640**	**92,852**	**36,050**	**123,090**	**36,228**	**58,083**

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

REFINERY REPORT—SEPT. 25, 2009

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	1,306	1,305	2,365	61	414	88	53
PADD 2	3,196	3,168	2,166	209	873	39	244
PADD 3	7,218	7,024	2,698	661	1,935	378	669
PADD 4	550	554	303	30	176	12	[1]64
PADD 5	2,651	2,540	1,566	385	539	116	—
Sept. 25, 2009	**14,921**	**14,591**	**9,098**	**1,346**	**3,937**	**633**	**1,030**
Sept. 18, 2009	**15,099**	**14,733**	**8,886**	**1,435**	**4,173**	**542**	**1,035**
Sept. 26, 2008[2]	**12,726**	**12,452**	**8,690**	**1,274**	**3,678**	**401**	**792**
	17,644 Operable capacity		**84.6 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 9-30-09	Pump price* 9-30-09	Pump price 10-1-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	194.0	240.5	367.3
Baltimore	199.5	241.4	371.3
Boston	201.5	243.4	367.4
Buffalo	194.5	255.4	362.3
Miami	207.8	259.4	364.3
Newark	200.6	233.2	357.3
New York	189.3	250.2	367.3
Norfolk	195.1	233.5	361.4
Philadelphia	199.7	250.4	369.4
Pittsburgh	199.2	249.9	366.3
Wash., DC	212.0	250.4	364.4
PAD I avg	199.4	246.2	365.3
Chicago	201.0	265.4	395.5
Cleveland	211.8	258.2	366.9
Des Moines	200.0	240.4	361.2
Detroit	206.0	265.4	367.3
Indianapolis	191.2	250.6	362.1
Kansas City	189.4	225.4	358.5
Louisville	208.9	249.8	373.1
Memphis	188.6	228.4	356.7
Milwaukee	201.1	252.4	367.2
Minn.-St. Paul	205.4	249.4	364.7
Oklahoma City	181.0	216.4	348.8
Omaha	177.9	223.2	342.3
St. Louis	184.4	220.4	355.4
Tulsa	178.0	213.4	350.0
Wichita	182.0	225.4	352.3
PAD II avg	193.8	238.9	361.5
Albuquerque	193.1	229.5	358.0
Birmingham	196.2	235.5	356.1
Dallas-Fort Worth	196.7	235.1	344.1
Houston	194.4	232.8	364.7
Little Rock	189.1	229.3	354.6
New Orleans	197.1	235.5	364.5
San Antonio	198.1	236.5	357.2
PAD III avg	194.9	233.4	357.0
Cheyenne	220.1	252.5	344.4
Denver	220.8	261.2	377.4
Salt Lake City	212.1	255.0	356.4
PAD IV avg	217.7	256.2	359.4
Los Angeles	235.9	303.0	367.0
Phoenix	226.5	263.9	352.9
Portland	241.6	285.0	357.9
San Diego	237.9	305.0	374.7
San Francisco	244.9	312.0	381.0
Seattle	243.3	299.2	363.0
PAD V avg	238.3	294.7	366.1
Week's avg.	**203.5**	**249.1**	**362.3**
Sept. avg.	**211.0**	**256.6**	**367.2**
Aug. avg.	**209.9**	**255.5**	**375.3**
2009 to date	**178.1**	**223.7**	—
2008 to date	**310.6**	**354.6**	—

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

REFINED PRODUCT PRICES

	9-25-09 ¢/gal		9-25-09 ¢/gal
Spot market product prices			
Motor gasoline		Heating oil No. 2	
(Conventional-regular)		New York Harbor	179.12
New York Harbor	184.90	Gulf Coast	178.62
Gulf Coast	180.15	Gas oil	
Los Angeles	183.65	ARA	182.41
Amsterdam-Rotterdam-Antwerp (ARA)	184.84	Singapore	182.26
Singapore	188.07	Residual fuel oil	
Motor gasoline		New York Harbor	155.29
(Reformulated-regular)		Gulf Coast	159.24
New York Harbor	182.03	Los Angeles	169.61
Gulf Coast	182.28	ARA	159.35
Los Angeles	195.15	Singapore	163.26

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

BAKER HUGHES RIG COUNT

	10-2-09	10-3-08
Alabama	6	4
Alaska	6	9
Arkansas	40	56
California	21	45
Land	20	45
Offshore	1	0
Colorado	39	106
Florida	0	3
Illinois	1	1
Indiana	2	2
Kansas	24	12
Kentucky	11	12
Louisiana	153	188
N. Land	100	85
S. Inland waters	9	20
S. Land	15	26
Offshore	29	57
Maryland	0	0
Michigan	0	2
Mississippi	8	15
Montana	4	9
Nebraska	1	0
New Mexico	46	94
New York	3	8
North Dakota	47	75
Ohio	8	10
Oklahoma	74	199
Pennsylvania	56	27
South Dakota	0	2
Texas	390	932
Offshore	2	9
Inland waters	0	0
Dist. 1	22	26
Dist. 2	13	32
Dist. 3	35	65
Dist. 4	34	88
Dist. 5	66	185
Dist. 6	44	135
Dist. 7B	10	29
Dist. 7C	30	62
Dist. 8	67	129
Dist. 8A	15	29
Dist. 9	22	41
Dist. 10	30	102
Utah	16	46
West Virginia	20	30
Wyoming	38	78
Others—HI-1; NV-2; OR-1; TN-1; VA-5	10	14
Total US	**1,024**	**1,979**
Total Canada	**238**	**431**
Grand total	**1,262**	**2,410**
US Oil rigs	303	422
US Gas rigs	712	1,544
Total US offshore	32	72
Total US cum. avg. YTD	**1,081**	**1,874**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	10-2-09 Rig count	10-2-09 Percent footage*	10-3-08 Rig count	10-3-08 Percent footage*
0-2,500	56	1.7	89	5.6
2,501-5,000	69	65.2	133	49.6
5,001-7,500	103	23.3	276	18.1
7,501-10,000	203	4.9	461	3.0
10,001-12,500	213	13.1	459	1.3
12,501-15,000	145	0.6	362	—
15,001-17,500	136	—	155	—
17,501-20,000	58	—	88	—
20,001-over	32	—	31	—
Total	**1,015**	**10.7**	**2,054**	**6.8**
INLAND	17		25	
LAND	962		1,977	
OFFSHORE	36		52	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]10-2-09	[2]10-3-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	675	688
California	660	655
Colorado	66	66
Florida	6	5
Illinois	29	27
Kansas	110	115
Louisiana	1,411	411
Michigan	18	18
Mississippi	62	60
Montana	89	86
New Mexico	163	159
North Dakota	196	193
Oklahoma	180	180
Texas	1,397	1,112
Utah	63	62
Wyoming	145	146
All others	66	73
Total	**5,357**	**4,077**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	10-2-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	70.00
California-Kern River 13°	61.10
Lost Hills 30°	69.45
Wyoming Sweet	61.70
East Texas Sweet	66.00
West Texas Sour 34°	61.50
West Texas Intermediate	66.50
Oklahoma Sweet	66.50
Texas Upper Gulf Coast	59.50
Michigan Sour	58.50
Kansas Common	65.50
North Dakota Sweet	56.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	9-25-09
United Kingdom-Brent 38°	67.28
Russia-Urals 32°	67.17
Saudi Light 34°	66.69
Dubai Fateh 32°	68.63
Algeria Saharan 44°	68.45
Nigeria-Bonny Light 37°	69.69
Indonesia-Minas 34°	69.50
Venezuela-Tia Juana Light 31°	67.36
Mexico-Isthmus 33°	67.25
OPEC basket	68.16
Total OPEC[2]	67.71
Total non-OPEC[2]	67.34
Total world[2]	67.55
US imports[3]	66.80

[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]

	9-25-09	9-26-09	9-25-08	Change, %
	bcf			
Producing region	1,145	1,126	829	**38.1**
Consuming region east	1,955	1,917	1,848	**5.8**
Consuming region west	489	482	421	**16.2**
Total US	**3,589**	**3,525**	**3,098**	**15.8**
	July 09	**June 08**	**Change, %**	
Total US[2]	**3,086**	**2,516**	**22.7**	

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

Statistics

Worldwide crude oil and gas production

	July 2009	June 2009	7 month average production 2009	7 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	July 2009	June 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	590	602	614	598	17	2.8	120.0	123.4	829.9
Bolivia	40	40	40	40	—	-0.8	40.0	40.0	285.0
Brazil	1,919	1,918	1,925	1,795	130	7.2	28.0	27.0	203.0
Canada	2,581	2,500	2,553	2,559	-6	-0.2	414.4	383.3	3,043.5
Colombia	657	660	647	569	77	13.6	22.0	22.0	152.0
Ecuador	470	480	479	500	-21	-4.3	2.0	2.0	14.0
Mexico	2,561	2,519	2,619	2,846	-227	-8.0	218.7	213.6	1,489.9
Peru	109	97	103	71	32	45.0	11.3	10.8	67.3
Trinidad	103	110	109	112	-3	-2.8	112.5	113.5	794.2
United States	5,175	5,183	5,225	5,118	108	2.1	1,854.0	1,814.0	12,821.0
Venezuela[1]	2,160	2,120	2,129	2,364	-236	-10.0	72.0	68.0	478.0
Other Latin America	83	83	83	83	—	-0.2	5.5	5.4	38.2
Western Hemisphere	**16,448**	**16,311**	**16,525**	**16,655**	**-130**	**-0.8**	**2,900.4**	**2,823.1**	**20,216.0**
Austria	16	17	18	17	1	6.1	4.9	4.8	33.2
Denmark	256	256	268	291	-22	-7.6	23.1	16.9	154.8
France	18	19	18	20	-2	-8.8	2.6	2.5	19.0
Germany	55	55	57	62	-5	-7.5	40.8	39.1	303.6
Italy	69	73	81	102	-21	-20.5	20.0	20.0	157.5
Netherlands	20	23	26	36	-10	-26.9	130.0	130.0	1,560.0
Norway	2,147	1,850	2,093	2,178	-84	-3.9	286.0	258.5	2,183.9
Turkey	48	46	44	40	4	9.2	0.0	0.0	0.0
United Kingdom	1,343	1,378	1,419	1,452	-33	-2.3	161.1	182.3	1,389.6
Other Western Europe	4	3	3	4	-1	-21.7	0.2	0.1	8.5
Western Europe	**3,976**	**3,720**	**4,029**	**4,202**	**-172**	**-4.1**	**668.6**	**654.2**	**5,810.1**
Azerbaijan	1,050	1,150	1,031	971	61	6.3	40.0	40.0	245.0
Croatia	14	14	14	15	-1	-6.8	5.4	4.9	36.6
Hungary	14	14	14	15	-1	-5.6	7.0	5.6	49.8
Kazakhstan	1,400	1,300	1,261	1,186	76	6.4	100.0	100.0	700.0
Romania	90	90	90	94	-4	-4.5	19.0	18.0	129.0
Russia	9,880	9,860	9,809	9,736	73	0.7	1,300.0	1,200.0	10,400.0
Other FSU	450	400	450	400	50	12.5	300.0	250.0	2,250.0
Other Eastern Europe	40	44	44	49	-5	-10.2	17.8	17.8	134.1
Eastern Europe and FSU	**12,937**	**12,872**	**12,713**	**12,465**	**248**	**2.0**	**1,789.2**	**1,636.2**	**13,944.5**
Algeria[1]	1,220	1,250	1,244	1,381	-137	-9.9	245.0	245.0	1,730.0
Angola[1]	1,790	1,750	1,739	1,923	-185	-9.6	6.0	5.0	34.0
Cameroon	72	70	74	87	-12	-14.2	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	630	640	646	667	-21	-3.2	120.0	120.0	855.0
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.4
Gabon	230	220	221	231	-10	-4.3	0.3	0.3	2.1
Libya[1]	1,540	1,540	1,556	1,740	-184	-10.6	38.0	36.0	259.0
Nigeria[1]	1,680	1,720	1,774	1,946	-171	-8.8	85.0	83.0	601.0
Sudan	500	500	500	483	17	3.6	—	—	—
Tunisia	81	80	84	83	2	1.9	7.3	7.5	56.3
Other Africa	221	221	221	221	—	—	9.1	8.3	61.3
Africa	**8,549**	**8,576**	**8,645**	**9,347**	**-703**	**-7.5**	**510.8**	**505.2**	**3,599.1**
Bahrain	170	170	169	170	—	-0.2	27.0	26.0	176.8
Iran[1]	3,820	3,800	3,747	3,941	-194	-4.9	290.0	285.0	2,005.0
Iraq[1]	2,480	2,430	2,363	2,444	-81	-3.3	22.0	20.0	137.0
Kuwait[1,2]	2,240	2,240	2,284	2,608	-324	-12.4	36.0	35.0	256.0
Oman	780	790	789	723	66	9.1	55.0	55.0	396.0
Qatar[1]	770	780	766	854	-89	-10.4	220.0	220.0	1,552.0
Saudi Arabia[1,2]	8,100	8,210	8,030	9,099	-1,069	-11.8	220.0	215.0	1,498.0
Syria	360	370	376	386	-10	-2.6	18.0	17.0	122.0
United Arab Emirates[1]	2,270	2,250	2,269	2,640	-371	-14.1	135.0	128.0	910.0
Yemen	260	265	275	311	-36	-11.7	0.0	0.0	0.0
Other Middle East	—	—	—	—	—	38.3	12.1	9.7	61.1
Middle East	**21,250**	**21,305**	**21,067**	**23,176**	**-2,109**	**-9.1**	**1,035.1**	**1,010.7**	**7,113.9**
Australia	474	457	465	439	26	6.0	141.4	138.5	862.8
Brunei	160	140	150	161	-11	-6.7	37.0	32.0	241.4
China	3,812	3,834	3,724	3,801	-77	-2.0	249.5	241.1	1,712.8
India	670	661	656	674	-18	-2.6	116.8	111.5	669.6
Indonesia[1]	880	870	860	860	—	—	210.0	200.0	1,400.0
Japan	14	14	16	17	-1	-7.1	9.3	8.7	72.0
Malaysia	720	730	733	760	-27	-3.6	140.0	135.0	960.0
New Zealand	49	44	46	60	-14	-23.0	14.0	12.0	85.9
Pakistan	62	62	64	67	-3	-5.0	121.6	121.3	857.5
Papua New Guinea	35	35	38	42	-4	-10.2	1.0	0.9	6.7
Thailand	236	242	243	225	18	8.0	34.0	32.0	232.3
Vietnam	330	300	304	290	14	4.9	15.0	14.5	102.5
Other Asia-Pacific	35	35	35	40	-5	-12.0	94.5	88.5	650.5
Asia-Pacific	**7,477**	**7,423**	**7,333**	**7,434**	**-101**	**-1.4**	**1,184.1**	**1,136.0**	**7,854.0**
TOTAL WORLD	**70,638**	**70,208**	**70,313**	**73,279**	**-2,967**	**-4.0**	**8,088.2**	**7,765.3**	**58,537.6**
OPEC	28,540	28,570	28,379	32,301	-3,922	-12.1	1,371.0	1,342.0	11,574.0
North Sea	3,765	3,502	3,801	3,939	-138	-3.5	509.0	496.6	4,195.2

[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.

Your marketplace for the oil and gas industry

DEADLINE for CLASSIFIED ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to CLASSIFIED SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-832-9201,
email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $390 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED CLASSIFIED: $4.00 per word per issue. 10% discount for three or more CONSECUTIVE issues. $80.00 minimum charge per insertion. Charge for blind box service is $56.00 No agency commission, no 2% cash discount. Centered/Bold heading, $9.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $83.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN CLASSIFIED SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR CLASSIFIED AD.*

EMPLOYMENT

EXECUTIVE VICE PRESIDENT

TIPRO

Texas Independent Producers and Royalty Owners Association (TIPRO) located in Austin seeks Executive Vice President to lead all aspects of Association. In addition to managing all personnel and finances, the EVP reports directly to the Board of Directors and implements plans to accomplish Association's mission, goals, membership recruitment, and fundraising. Successful candidate will have a Bachelor's degree and management experience with working knowledge in the oil and natural gas business. Must possess excellent oral and written communication skills. Interested parties should send a resume and cover letter to hrtipro@gmail.com on or before October 16th. Finalists will be contacted for writing samples and interviews with search committee.

Please visit ***www.Tipro.org*** to view a complete job description and posting information.

Scientific Professionals - ExxonMobil, a global leader in the petroleum and petrochemicals industry is seeking Senior Geophysicists - Geophysical Applications for their Houston, TX facility. Job duties include interpreting, processing and acquiring seismic data, as well as performing well log and rock properties analysis, seismic modeling, inversion, DHI analysis, qualitative and quantitative seismic attribute analysis, domain conversions and seismic-to-well-tie analysis. Requires a MS degree in Geophysics or a related field and one year of experience. Experience must include GeoFrame, Petrel, Hampson-Russell, Jason, GeoDepth, RokDoc, Promax and Matlab software. Experience must also include both clastic and carbonate environments. Please submit your cover letter and resume to our web site: www.exxonmobil.com\ex. Please apply to Senior Geophysicists - Geophysical Applications - 8711BR and reference requisition number 8711BR in both letter and resume. ExxonMobil is an Equal Opportunity Employer.

Smith International, Inc. in Houston, Texas seeks Engineering Manager to manage the development team supporting Smith Engineering Systems Department of the development, implementation and maintenance of advanced PDM/PLM (specifically, MatrixOne/Engineering Central) systems primarily in support of design and manufacturing engineering disciplines. Must have Bachelors or Masters degree in Comp. Science, Mechanical or Manufacturing Engineering plus experience. Mail resume to J. Brown, HR, Smith International, Inc. 4607 World Houston Pkwy, Ste. 100, Houston, TX 77032. Must indicate job code EMHOU on resume.

EQUIPMENT FOR SALE

REFRIGERATION PLANTS

5 and 12 MMSCFD, 1100, T. H. RUSSELL
4 and 7 MMSCFD, 1000, NATCO
8 MMSCFD, DARENCO, 1-3 MMSCFD PROCESS EQPT.
OTHERS AVAILABLE
J. T. PLANTS
0.5 – 30 MMSCFD
DEHYDRATORS 8" – 36"
5 GPM AMINE
5,000 – 30,000 GALLON LPG TANKS
318-425-2533, 318-458-1874
regardres@aol.com

NATCO
Producing Solutions

Water, Oil and Gas Treatment/Conditioning Equipment

For Sale, Lease, Contract Service

Separators, Hydrocyclones, Float Cells, Filtration, Electrostatic Oil Treaters, Amine Units, Glycol Units, JT-Plants, Refrigeration Units, LACT Units

For Information Call 713.849.7520

www.NATCOGroup.com

Classified Advertising

EQUIPMENT FOR SALE

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS:	**10 - 600 MMCFD**
AMINE PLANTS:	**60 - 5000 GPM**
SULFUR PLANTS:	**10 - 1200 TPD**
FRACTIONATION:	**1000 – 15,000 BPD**

HELIUM RECOVERY: 75 & 80 MMCFD

NITROGEN REJECTION: 25 – 80 MMCFD

ALSO OTHER REFINING UNITS

We offer engineered surplus equipment solutions.

Bexar Energy Holdings, Inc.
Phone 210 342-7106
Fax 210 223-0018
www.bexarenergy.com
Email: info@bexarenergy.com

FOR SALE / RENT

5.2 MW MOBILE GEN SETS
CALL: 800-704-2002

SOLAR TAURUS 60

- GAS - LOW NOx (OIL)
- 60 Hz - 13.8KV or 50 Hz - 11KV
- LOW HOUR - SOLAR SERVICED

DIESELS • TURBINES • BOILERS

24/7 EMERGENCY SERVICE
IMMEDIATE DELIVERY

www.wabashpower.com | info@wabashpower.com
Phone: 847-541-5600 Fax: 847-541-1279

wabash POWER EQUIPMENT CO.

444 Carpenter Avenue, Wheeling, IL 60090

For Sale or Contract
Amine Plant 245 gpm
As is or Reconditioned
Turn Key Construction available
Bottom Line Services Inc.
361-449-6992
www.bottomlineservicesinc.com
gblevins@blsinc.us

CONSULTANT

Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment-120 specialists upstream, downstream gas and biofuels.
Email: contato@expetro.com.br
Web: www.expetro.com.br-Rio de Janeiro, Brazil

BUSINESS OPPORTUNITY

LOOKING FOR INVESTOR
308 million barrels proven.
503-253-7400, Fax 503-253-8888
Email: diamonda@teleport.com

Want to purchase minerals and other oil/gas interests. Send details to: P.O. Box 13557, Denver, CO 80201.

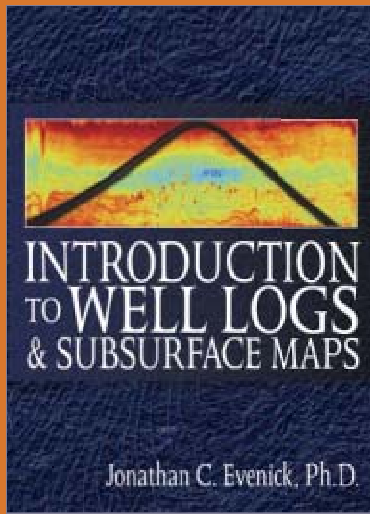
GEOLOGIST has extensive Gulf Coast 2-D seismic data-base with numerous mapped prospects and anomalies. Seeks funding for additional seismic, leasing and drilling. 713-504-7291.

Hiring?
Selling Equipment?
Need Equipment?
New Business Opportunity?

Contact: Glenda Harp
+1-918-832-9301 or
1-800-331-4463, ext. 6301
Fax: +1-918-832-9201

SUBSURFACE MAPS
DE-MYSTIFIED

NOW AVAILABLE!



Introduction to Well Logs & Subsurface Maps
By Jonathan C. Evenick, PhD.
ISBN: 978-1-59370-138-3
Price: $59.00 US

Know what you are investigating and exactly what type of map is most appropriate!

WHAT YOU'LL FIND
- *Introduction to basic well logs and subsurface maps.*
- *Applied projects that allow users to critique computer-generated maps and data.*
- *Hands-on exercises showing how each map type is generated and what applications they have.*

Order online at www.PennWellBooks.com

PennWell

Advertising Sales / Advertisers Index

Houston

Director of Sales, Tripp Wiggins; Tel: (713) 963-6244, Email: trippw@pennwell.com. U.S. Sales Manager, Marlene Breedlove; Tel: (713) 963-6293, E-mail: marleneb@pennwell.com. Regional Sales Manager, Mike Moss; Tel: (713) 963-6221, E-mail: mikem@pennwell.com. PennWell - Houston, 1455 West Loop South, Suite 400, Houston, TX 77027. Fax: (713) 963-6228

South/Southwest /Texas/Northwest/Midwest/Alaska

Marlene Breedlove, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com

Northeast/Texas/Southwest

Mike Moss, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6221, Fax: (713) 963-6228; E-mail: mikem@pennwell.com

Louisiana/Canada

Stan Terry, 1455 West Loop S. Ste. 400, Houston, TX 77027; Tel: (713) 963-6208, Fax: (713) 963-6228; E-mail: stant@pennwell.com

Scandinavia/Denmark/The Netherlands/Middle East/Africa

David Betham-Rogers, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France; Tel: 33.2.33.282584, Fax: 33.2.33.274491; E-mail: davidbr@pennwell.com

United Kingdom

Stephen Wilding, 188 Gordon Avenue, Camberley, GU15 2NT United Kingdom Tel: +44.7545.829.891, Fax: +44 7545.829.891; E-mail: stephenw@pennwell.com

France/Belgium/Spain/Portugal/Southern Switzerland/Monaco

Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33(0)1.3071.1119, Fax: 33(0)1.3071.1119; E-mail: danielb@pennwell.com

Germany/Austria/Northern/Switzerland/Eastern Europe/Russia/Former Soviet Union

Sicking Industrial Marketing, Kurt-Schumacher-Str. 16, 59872, Freienohl, Germany. Tel: 49(0)2903.3385.70, Fax: 49(0)2903.3385.82; E-mail: wilhelms@pennwell.com; www.sicking.de <http://www.sicking.de> Andreas Sicking

Japan

e.x.press sales division, ICS Convention Design Inc. 6F, Chiyoda Bldg., 1-5-18 Sarugakucho, Chiyoda-ku, Tokyo 101-8449, Japan, Tel: +81.3.3219.3641, Fax: 81.3.3219.3628; Kimie Takemura, Email: takemura-kimie@ics-inc.co.jp; Manami Konishi, E-mail: konishi-manami@ics-inc.co.jp; Masaki Mori, E-mail: masaki.mori@ics-inc.co.jp

Brazil

Grupo Expetro/Smartpetro, Att: Jean-Paul Prates and Bernardo Grunewald, Directors, Ave. Erasmo Braga 22710th and 11th floors Rio de Janeiro RJ 20024-900 Brazil; Tel: 55.21.3084.5384, Fax: 55.21.2533.4593; E-mail: jpprates@pennwell.com.br and bernardo@pennwell.com.br

Singapore/Australia/Asia-Pacific

Michael Yee, 19 Tanglin Road #09-07, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel: 65 6737.2356, Fax: 65.6734.0655; E-mail: yfyee@singnet.com.sg

India

Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91.11.6283018/19, Fax: +91.11.6228 928; E-mail: rajan@interadsindia.com

Italy

Paolo Silvera, Viale Monza, 24 20127 MILANO Italy; Tel:+02.28.46 716; E-mail: info@silvera.it

This index is provided as a service. The publisher does not assume any liability for errors or omission.

From the Subscribers Only area of OIL&GAS JOURNAL online www.ogjonline.com

Gas-price relief, if not reshaping, seen at meeting

Setting offers important context to predictions of near-term gains for recently abysmal gas prices in the US.

Such a message naturally receives a warm greeting from struggling developers of unconventional gas resources. But the greeting comes with irony.

Success of those developers is part of the problem. At PennWell Corp.'s Unconventional Gas International Conference

The Editor's Perspective

by Bob Tippee, Editor

& Exhibition in Fort Worth, Advanced Resources International Pres. Vello Kuuskraa showed why this is so.

Development of gas-bearing coalbeds, tight sands, and shales has put US production capacity on a strong growth trend for the first time in a decade.

While tight sands still dominate unconventional gas production, the main growth is in shales, output from which has quadrupled in 5 years, Kuuskraa said.

The supply surge coincides with a demand decline occasioned by economic recession, pushing average wellhead prices to $3.43/Mcf in July from more than $10/Mcf a year earlier, according to the Energy Information Administration. But two analysts at the conference offered comfort.

David Pursell, managing director and head of macro research at Tudor, Pickering & Holt, predicted the gas price will rebound to $7.50/Mcf next year and settle into a longer-term range of $6-6.50/Mcf.

And Don Warlick, president of Warlick International, said demand recovery will move gas prices back to the $6/Mcf neighborhood by the end of first-quarter 2010.

An audience member offered the intuition that, just as nature abhors a vacuum, economic laws won't allow gas to trade indefinitely at a steep energy-equivalent discount to oil.

And during a panel discussion, Harvey Klingensmith, president of Stone Mountain Resources, a private producer active in the Horn River shale play of British Columbia, opined about a new price band for gas.

This might occur, he said, as decision-making about drilling into aerially extensive unconventional reservoirs comes to resemble that of manufacturing.

If he's right, unconventional gas will have reshaped more than development technologies for hydrocarbon resources. And if the new shape means an end to 300% price swings, who's to argue?

For most producers in a tough year, though, predictions about $6-7/Mcf gas sometime in 2010 may feel like hope enough for now.

(Online Oct. 2, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Deutsche Bank alters popular commodity fund

In a recent filing with the US Securities and Exchange Commission, Deutsche Bank AG said it will change the composition of its $3.3 billion PowerShares DB Commodity Index Tracking Fund (DBC) to become more diversified and to comply with position limits imposed by the US Commodity Futures Trading Commission.

That includes reducing some of its previous exposure on West Texas Intermediate on the New York Mercantile Exchange and adding North Sea Brent crude on the IntercontinentalExchange Inc. to the six commodities it currently tracks. That will be its first investment in a non-US energy commodity. DBC also will add natural gas and reformulated blend stock for oxygenate blending (RBOB) while reducing its exposure to heating oil. The changes should be effective Oct. 30.

"This should translate in the liquidation of about 8,000 WTI contracts and the buying of about 6,000 Brent contracts, the liquidation of about 3,000 heating oil contracts and the buying of about 5,000 gasoline contracts," said Olivier Jakob at Petromatrix, Zug, Switzerland. He expects Deutsche Bank to effect the changes by Oct. 19 or earlier "through its trading desks." The fund currently owns November contracts for WTI and heating oil.

"These changes are provoked by the CFTC revocation (effective at the end of October) of the position exemption previously given to Deutsche. The Deutsche move to a broader composition however means that its commodity index is losing some of the traits that made it different [from] other indices as it becomes just another very broad index (up to now it was concentrated in only six commodities)," Jakob said.

He said, "We are approaching the time where more commodity indices will announce their commodity weights for 2010, and it will be interesting to see if they follow Deutsche in moving more of the crude weights towards the Brent ICE contract."

The flagship of Deutsche Banks commodity services family of funds, the DBC enters into long futures contracts and collateralizes those contracts with US 3-month Treasury bills. It provides investors with broadly diversified exposure to the returns of the commodities markets, which have historically allowed investors to diversify their stock and bond portfolios.

The CFTC earlier instructed Deutsche Bank to reduce positions in corn and wheat futures through its $2.2 billion PowerShares DB Agriculture Fund (DBA). It also revoked previous exemptions allowing the two funds to exceed position limits on agricultural products.

War with Iran?

Analysts in the Houston office of Raymond James & Associates Inc. said Oct. 5, "Based upon the recent political rhetoric, we now think the risk of an Iranian oil supply interruption is meaningfully higher than it was a few months ago. In fact, we now believe there is better than a 50% probability that some type of military confrontation with Iran will occur in the course of the next 12 months."

The analysts noted an Oct. 3 article in the New York Times citing "a leaked internal report from the International Atomic Energy Agency that says Iran has essentially worked out all of its technical issues to build a nuclear weapon." The only remaining step, it said, is enriching a sufficient quantity of weapons-grade uranium, which Western intelligence sources speculate could be just a matter of months if enrichment continues at the current pace.

The Times article said conclusions of the report by IAEA experts are tentative but go "well beyond the public positions" taken by the US and others. Earlier US President Barack Obama joined representatives from Russia, China, France, the UK, and Germany in talks with Iranian officials in Geneva, where he said: "We have made it clear that we will do our part to engage the Iranian government on the basis of mutual interests and mutual respect, but our patience is not unlimited."

Raymond James analysts said, "In the past 2 weeks, the risk of an Iranian oil supply disruption has increased sharply while the oil markets seem to have completely ignored the potential change to the global oil supply-demand equation. Normally during geopolitical crises involving the Middle East, oil prices take notice well before military action actually begins.

"This was the case, for example, in the run-up to war with Iraq in 2003. In fact, the same was true in early 2006, when Iran announced the end of its moratorium on nuclear enrichment. But here we are, in the midst of what some are calling 'a Cuban Missile Crisis in slow motion,' with the Iranian regime playing hardball and tensions palpably rising in the region and the oil market just yawns," they said.

(Online Oct. 5, 2009; author's e-mail: samf@ogjonline.com)


FATHOM™
CERTIFIED
CHEMICALS