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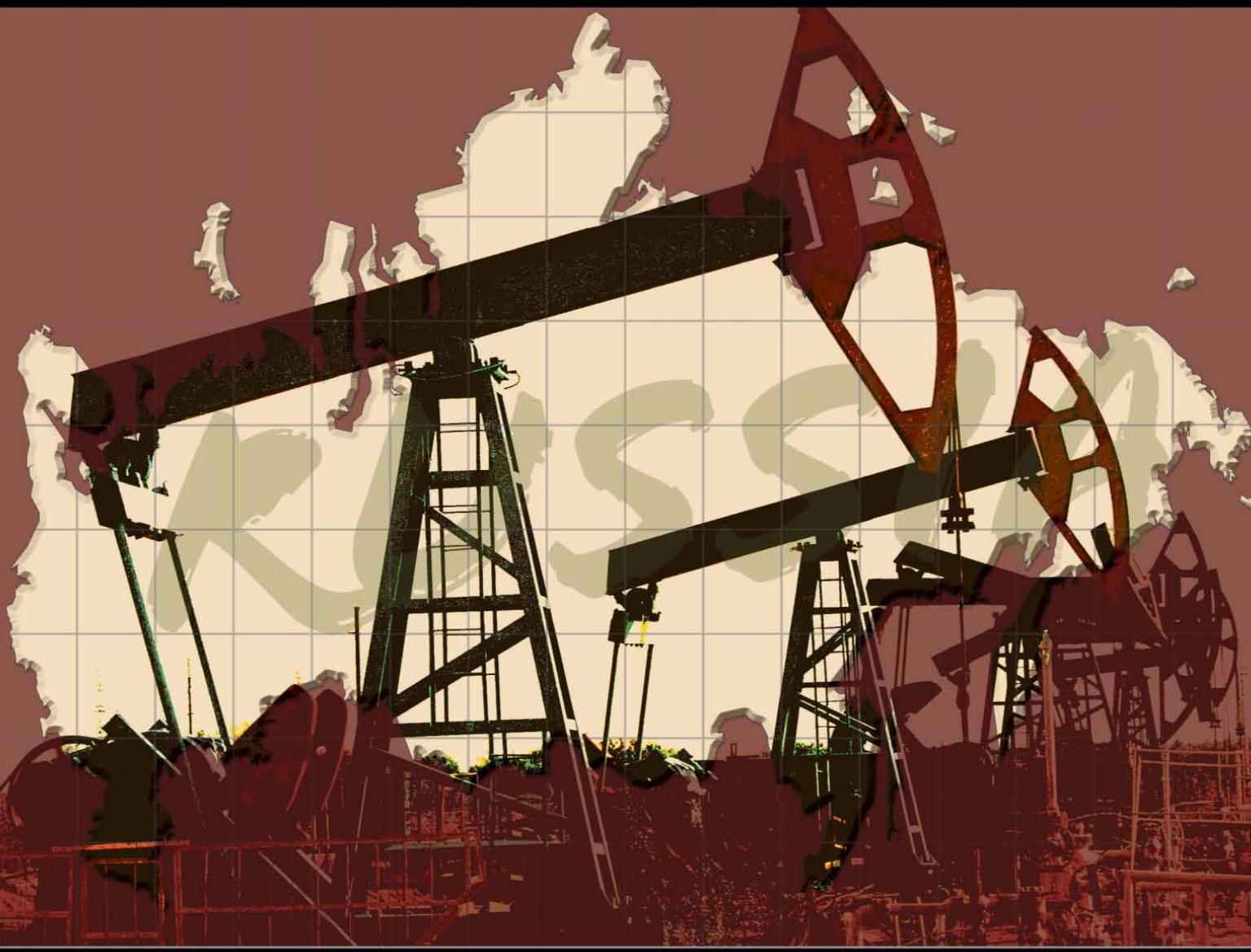

## The New Russian Regime

*Emphasis on urban areas affects drilling in Ohio*
*Real-time well optimization stabilizes, adds production*
*Composition complicates processing plans for US shale gas*
*US LNG imports signal unexpected role for gas markets*

OIL&GAS JOURNAL®

Mar. 9, 2009
Volume 107.10

## THE NEW RUSSIAN REGIME

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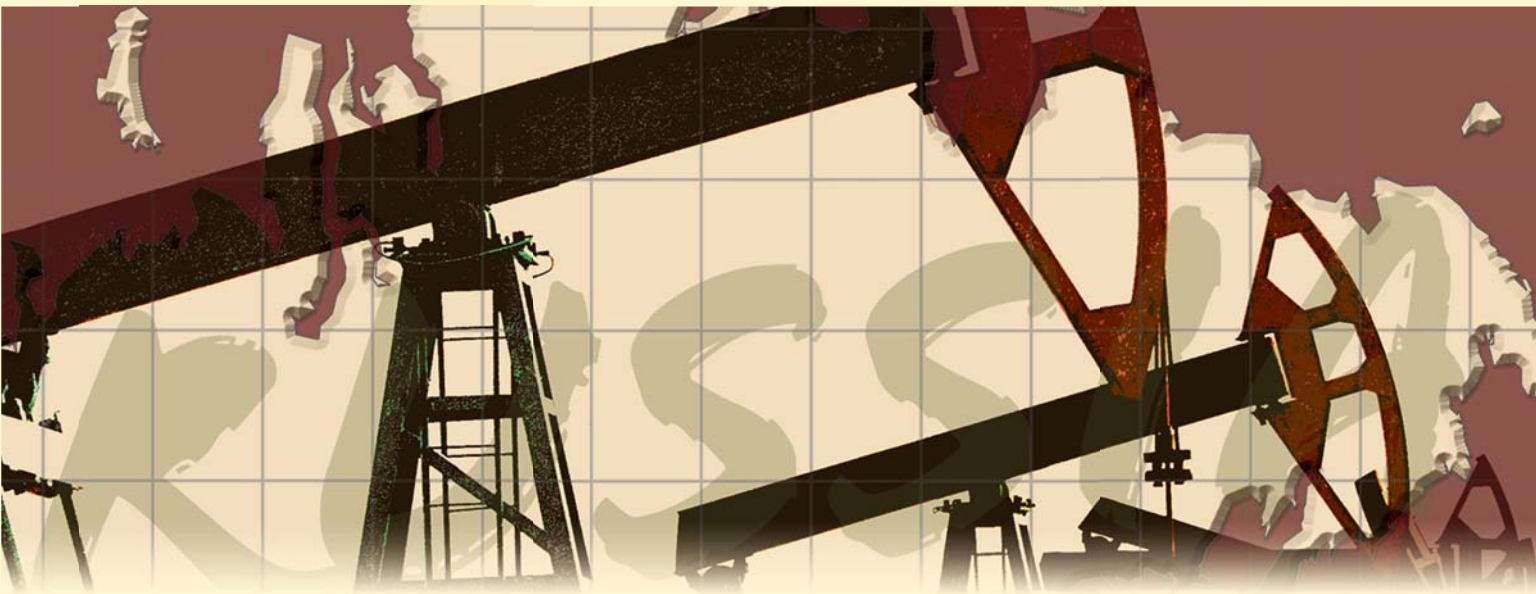

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## COVER

Russia's oil and gas industry is facing momentous challenges, with the devaluation of the ruble, low oil and gas prices, difficulties in obtaining credit for major projects, high taxes, and altercations with transit countries. Transit disputes have led to disruption of gas supplies to major European markets, some of which are seeking gas supplies elsewhere. The articles on pp. 18, 26, and 27 address these issues as Russia's industry seeks solutions to its problems. The cover illustrates production operations in giant Samotlor oil field in West Siberia. Samotlor production peaked at 3.2 million b/d in 1980 and fell to 400,000 b/d in 1999 but has climbed back to 600,000 b/d under a redevelopment program by TNK-BP, which became operator in 2003. Photo from TNK-BP.

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## General Interest — Quick Takes

### Alberta offers incentives to boost drilling

Alberta oil and gas producers have been offered royalty incentives from a provincial government hoping to revive drilling.

The government has reduced royalty for conventional wells spudded between Apr. 1 and Mar. 31, 2010, and for wells coming onto production in that period.

The drilling incentive is a crown royalty credit of $200/m of hole drilled. The credit can't reduce an operator's overall royalty rate to below 5%.

Benefits will be greatest for the smallest producers, determined by a sliding scale based on production.

New wells eligible for the production incentive will receive a maximum royalty rate of 5% for 12 calendar months or until production reaches 50,000 bbl of crown production or 500 MMcf of natural gas.

A single qualifying well can receive both the drilling and production incentives.

The incentives don't apply to oil sands drilling or production.

"This program is focused on keeping drilling and service crews at work while also recognizing the enormous economic benefits this activity has in Alberta communities," the provincial energy department said in a statement.

Tristone Capital Inc., noting that drilling in Alberta is expected to decline 28% this year, greeted the incentives skeptically.

"We are long [on] supply in North America, and adding productive capacity today is not desirable," it said. "And we believe the margin of cash that is retained by the incentives will predominantly focus on debt reduction."

### Venezuela to allow Panama to join Petrocaribe

Venezuela, following a meeting between Panamanian President Martin Torrijos and his Venezuelan counterpart Hugo Chavez, will allow Panama to join Venezuela's Petrocaribe fuel assistance program.

Venezuela "takes note" and accepts "with great satisfaction" Torrijos' request, which "will contribute to strengthening the ties of cooperation among the countries making up the initiative," said Venezuela's foreign ministry after the two presidents met.

Launched by Chavez in 2005, Petrocaribe now includes 18 countries in and around the Carribbean Sea. Under the initiative, member countries pay 60% of the cost of Venezuelan oil at the time of purchase and can defer the remaining 40% as financing for development projects, repayable over 25 years at a 1% interest rate.

During 2005-08, Petrocaribe distributed some 59 million bbl of oil and derivatives to its members, who saved $921 million, according to Venezuelan government data. Cuba is the main beneficiary, receiving about 92,000 b/d of Venezuelan oil, while the other nations in the scheme each receive around 80,000 b/d.

Last December, Panama's trade and industry ministry reported that studies on the proposed construction of a 350,000 b/d refinery at the Port of Armuelles were almost finished. In 2007, Panama agreed to cooperate with Qatar Petroleum and Occidental Petroleum on the project. The two companies commissioned Foster Wheeler to conduct the studies.

### Oil market tough on lower-middle income areas

Lower-middle income countries were the most vulnerable to global oil price increases over 10 years, according to a new study released by the World Bank's Oil, Gas & Mining Policy division.

The study, presented Mar. 3 during the bank's week-long extractive industries conference, defined vulnerability as the ratio of the value of net oil imports to gross domestic product. A country's oil price vulnerability rises if its oil consumption increases and its oil production decreases per unit of GDP, it explained.

"For countries that consume more [oil] than they produce, a change in the balance of—the value of net oil imports is a measure of the adjustment that will have to be made when oil prices rise (in the absence of other offsetting exogenous shocks). The adjustment will have to be made by deflating the economy to restore the balance of payments or running down foreign exchange reserves," it said.

The study, "Vulnerability to Oil Price Increases," included data for 161 countries and covered the 1996-2006 period. It was written by Robert Bacon, a consultant to the World Bank division, and Masami Kojima, a lead energy specialist in the group. A summary is available online at http://rru.worldbank.org/documents/publicpolicyjournal/320-OilPrices.pdf.

The report also found that factors related to oil's consumption and production other than its price also influenced a country's oil price vulnerability. Consumption-related factors are oil's share in total commercial energy use, the ratio of commercial energy consumed to GDP (or energy intensity), and the proxy-real exchange rate. Production-related influences also included oil production levels and the inverse of GDP, it said.

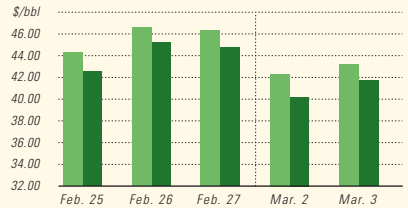
"This study demonstrates that policymakers can, to varying degrees, reduce the vulnerability of their countries' economies to oil prices by influencing import dependence and reducing the economy's energy intensity, among other factors," said Somat Varma, the World Bank department's director.

### Mixed results to come from USFS move to DOI

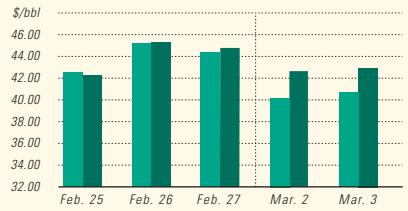
Moving the US Forest Service (USFS) into the US Department of the Interior could potentially create long-term benefits and short-term problems, the Government Accountability Office said in a Feb. 24 report.

# Industry Scoreboard

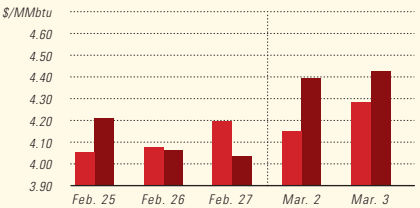
## IPE BRENT / NYMEX LIGHT SWEET CRUDE



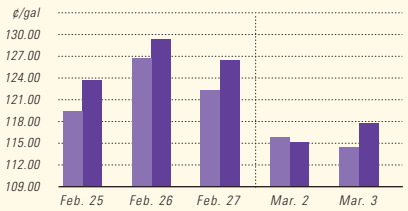

## WTI CUSHING / BRENT SPOT



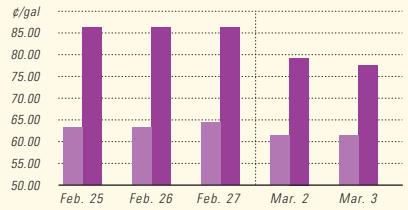

## NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



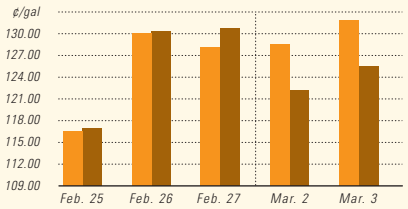

## IPE GAS OIL / NYMEX HEATING OIL




## 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.

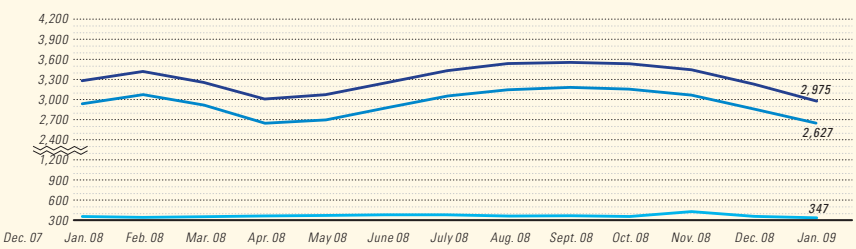
## US INDUSTRY SCOREBOARD — 3/9

| Latest week 2/20 | 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 | 8,985 | 8,833 | 1.7 | 8,872 | 8,828 | 0.5 |
| Distillate | 4,171 | 4,238 | –1.6 | 4,124 | 4,209 | –2.0 |
| Jet fuel | 1,303 | 1,540 | –15.4 | 1,349 | 1,546 | –12.7 |
| Residual | 624 | 591 | 5.6 | 617 | 672 | –8.1 |
| Other products | 4,640 | 4,687 | –1.0 | 4,614 | 4,736 | –2.6 |
| TOTAL DEMAND | 19,723 | 19,889 | –0.8 | 19,577 | 19,991 | –2.1 |
| *Supply, 1,000 b/d* | | | | | | |
| Crude production | 5,296 | 5,107 | 3.7 | 5,142 | 5,103 | 0.8 |
| NGL production[2] | 2,118 | 2,180 | –2.8 | 2,180 | 2,164 | 0.8 |
| Crude imports | 9,313 | 9,733 | –4.3 | 9,630 | 9,810 | –1.8 |
| Product imports | 2,946 | 3,157 | –6.7 | 3,163 | 3,253 | –2.8 |
| Other supply[3] | 1,472 | 1,451 | 1.4 | 1,508 | 1,012 | 49.0 |
| TOTAL SUPPLY | 21,145 | 21,628 | –2.2 | 21,623 | 21,341 | 1.3 |
| *Refining, 1,000 b/d* | | | | | | |
| Crude runs to stills | 14,242 | 14,327 | –0.6 | 14,242 | 14,715 | –3.2 |
| Input to crude stills | 14,629 | 14,989 | –2.4 | 14,629 | 15,018 | –2.6 |
| % utilization | 83.0 | 85.2 | — | 83.0 | 85.4 | — |

| Latest week 2/20 | Latest week | Previous week[1] | Change | Same week year ago[1] | Change | Change, % |
|---|---|---|---|---|---|---|
| *Stocks, 1,000 bbl* | | | | | | |
| Crude oil | 351,347 | 350,630 | 717 | 308,505 | 42,842 | 13.9 |
| Motor gasoline | 215,342 | 218,664 | –3,322 | 232,619 | –17,277 | –7.4 |
| Distillate | 141,634 | 140,752 | 882 | 119,952 | 21,682 | 18.1 |
| Jet fuel–kerosine | 40,474 | 40,957 | –483 | 40,083 | 391 | 1.0 |
| Residual | 36,397 | 36,320 | 77 | 36,672 | –275 | –0.7 |
| *Stock cover (days)[4]* | | | Change, % | | Change, % | |
| Crude | 24.9 | 24.7 | 0.8 | 21.2 | 17.5 | |
| Motor gasoline | 24.0 | 24.6 | –2.4 | 25.8 | –7.0 | |
| Distillate | 34.0 | 33.2 | 2.4 | 27.5 | 23.6 | |
| Propane | 25.7 | 24.2 | 6.2 | 19.3 | 33.2 | |
| *Futures prices[5]* 2/27 | | | Change | | Change | % |
| Light sweet crude ($/bbl) | 42.18 | 36.99 | 5.19 | 99.45 | –57.27 | –57.6 |
| Natural gas, $/MMbtu | 4.13 | 4.13 | 0.01 | 9.00 | –4.86 | –54.1 |

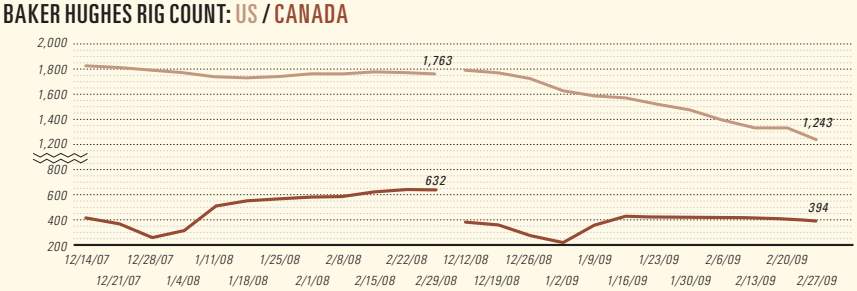
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

GAO said according to many agency officials and experts, where the mission of the USFS, which now is part of the US Department of Agriculture, is aligned with those of DOI agencies (in particular, its multiple use missions which is comparable to that of the US Bureau of Land Management), a move could increase some of the agencies' programs and policies overall effectiveness.

"Conversely, most agency officials and experts GAO interview believed that few short-term efficiencies would be realized from such a move, although a number said opportunities would be created for potential long-term efficiencies," GAO's report continued.

"Many officials and experts suggested that if the objective of a move is to improve land management and increase the effectiveness and efficiency of the agencies' diverse programs, other options might achieve better results," it added.

The proposal is periodically discussed because BLM and the USFS often manage adjacent federal acreage. The agencies already work together on some activities, including onshore oil and gas lease sales in which BLM sometimes includes some USFS tracts at that agency's request.

### Algeria's Khelil calls for tax changes in Europe

Gas-consuming nations need to rethink their tax policies if they are to encourage gas imports and remove barriers, said Chakib Khelil, Algeria's energy minister, at a forum in Algiers. He said that existing tax policies only protected narrow interests and hindered the expansion of the gas industry in Europe.

Algeria is the third-largest exporter of gas to Europe. Khelil said that, as gas is cleaner than coal, it must be given a tax advantage.

State-owned Sonatrach is constructing two major gas pipelines to Europe, each with a capacity of 8 billion cu m/year. Medgaz and Galsi are expected to be completed by yearend and in 2012 respectively. Sonatrach also announced plans to boost capacity of two existing pipelines linking it to Italy and Spain by 7.7 billion cu m in 2009.

But whether Algeria can deliver these output increases is questionable, according to analysts, considering the few companies that were awarded licenses in its latest licensing round, the location of small discoveries, and the need to build new pipelines to bring them to market (OGJ Online, Feb. 10, 2009). ✦

## Exploration & Development — *Quick Takes*

### BP makes oil discovery with Leda off Angola

BP Exploration (Angola) has made its seventeenth discovery with its Leda well, which was drilled on ultradeepwater Block 31. On test, Leda flowed 5,040 b/d through a $^{36}/_{64}$-in. choke.

The Leda well, which reached 5,907 m TD subsea, was drilled through salt to access the oil-bearing sandstone reservoir.

Leda lies in the central northern portion of Block 31, 415 km northwest of Luanda field and 12 km southwest of Marte field. It was found in 2,070 m of water.

BP, as operator, holds a 26.67% interest in Leda. Partners are Esso Exploration & Production Angola (Block 31) Ltd. 25%, Sonangol P&P 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and TEPA (Block 31) Ltd. 5%.

### InterOil's Antelope-1 shows promise in PNG

InterOil Corp. reported that its Antelope-1 wildcat onshore Papua New Guinea could contain sufficient gas to supply the first LNG train in its proposed Liquid Niugini Gas project near Port Moresby after the well flowed a record 382 MMcfd of gas. The flow was accompanied by 5,000 b/d of condensate.

Antelope has reportedly intersected the largest onshore vertical hydrocarbon column—2,600 ft (gross)—in the Asia-Pacific region. The company's reservoir engineers estimate the discovery could contain more than 10 tcf of gas. Independent estimates are now being conducted.

Put with previous discoveries at the Elk field in the region InterOil says it is proceeding with plans for a two-train LNG plant capable of producing up to 9 million tonnes/year of LNG beginning late 2013 or early 2014.

Liquid Niugini Gas was originally a joint venture of InterOil, Merrill Lynch, and finance firm Clarion Finance. InterOil says it has now acquired Merill Lynch's stake in the project.

It previously selected Bechtel to carry out front-end engineering and design as well as engineering, procurement, and contract work for the LNG plant. In addition, the JV had also chosen ConocoPhillips's optimized cascade process technology for the plant design.

The plant is to be built near InterOil's Napa Napa refinery in Port Moresby and will be capable of producing 5 million tonnes/year of LNG from a single-processing train. Despite the success at Antelope, the second train remains an option that has yet to be confirmed.

### Pemex makes oil, gas finds in Gulf of Mexico

Mexico's state-owned Petroleos Mexicanos, which has budgeted more than $12.2 billion for oil and gas exploration in 2009-12, has discovered "significant" amounts of natural gas and condensate with its Tsimin-1 wildcat well drilled in the Gulf of Mexico.

The Tsimin-1 well had initial production of 4,400 boe/d, Pemex said.

Meanwhile, the state firm also announced the onset of gas production of the Cali-1 well in its Burgos project, with production starting at 9.1 MMcfd of gas.

Pemex, which drilled the discovery well in August 2008 on Mision block in Burgos, said the development of the field will provide an additional 90-110 MMcfd of gas.

Pemex also listed four light oil discoveries in its fourth-quarter 2008 financial results, with the Xanab-DL1 offshore well being the most productive at 9,200 b/d of oil.

The discoveries coincide with a statement by Pemex Chief Executive Officer Jesus Reyes Heroles stating that the firm likely discovered 30-35% more oil and gas in 2008 than in 2007.

"It was a very good year in general terms and very important with respect to the previous year," Reyes Heroles said. During 2007, 1.053 billion boe were incorporated, he said.

He said the firm, before making any more details public, is awaiting final certification of its reserves by independent consulting firms.

### Corcel block in Colombia's Llanos emerges

Production has built to more than 13,000 b/d from two wells on the Corcel block east of Villavicencio in Colombia's Llanos basin, said Petrominerales Ltd., Bogota.

With Corcel-D1 and D2 producing from Eocene Mirador, Corcel-D3 topped Mirador 8 ft high to prognosis and encountered hydrocarbon shows. Corcel-E1 is to spud later in March.

The Corcel central processing facility is capable of handling 70,000 b/d of fluid, and an upgrade to 140,000 b/d is to be complete in the third quarter.

An offloading station at Monterrey, 77 km from Corcel, that will provide preferential rights to deliver as much as 20,000 b/d into Colombia's main export pipeline is 42% complete. Early start-up of 11,000 b/d of delivery capacity is planned for May 2009. Full capacity is due in the third quarter. The facility is to cut trucking costs by as much as $6/bbl.

Petrominerales was awarded blocks 25 and 31 totaling 333,708 acres north of Corcel in late 2008. It will spud its first exploration well on the Guatiquia block just southwest of Corcel in July targeting a 3D seismic prospect. ✦

## Drilling & Production — *Quick Takes*

### Kipper drilling to begin in 12 months

Esso Australia, Melbourne, has contracted to begin development drilling on its Kipper gas-condensate field in Bass Strait early in 2010.

The company has secured the use of the Ocean Patriot semisubmersible under an agreement with Diamond Offshore and Apache Energy for some well slots in between its program for Apache in the region next year.

The Kipper drilling project could take 3-6 months.

The field lies 45 km offshore in 100 m of water. It has a confirmed resource of 620 bcf of gas and 30 million bbl barrels of condensate.

First gas production, which will be piped to shore via the West Tuna platform, is targeted for the first half of 2011. Output is expected to be around 75 terajoules/day with an estimated field life of 11 years.

Partners in the Kipper JV are Esso as operator with 32.5%, Santos 35%, and BHP Billiton with 32.5%.

### Rwanda's Lake Kivu gas project advances

ContourGlobal, New York, signed a contract with Rwanda's government to extract solution gas from Lake Kivu to generate electricity.

The $325 million KivuWatt project is to start generating 25 Mw in 2010 and another 75 Mw 2 years later. Power from a plant at Kibuye, Rwanda, is expected to ultimately supply Uganda, Congo (former Zaire), and Burundi as well as Rwanda.

ContourGlobal plans to develop, build, and operate several barges to extract methane from lake water at 350 m. It will process the gas and move it by pipeline to the Kibuye generator, which will more than double the amount of power produced in Rwanda.

Rwanda's Electrogaz power distributor will buy the electricity under a 25-year contract.

ContourGlobal has been designing and developing the project for 2 years and has run extensive seabed surveys and methane gas sampling at the lake's lower depths.

The lake is estimated to contain nearly 2 tcf of methane and five times that much carbon dioxide subject to explosive release within a few hundred years in connection with nearby volcanic activity. About 1.3 tcf is believed recoverable. The volumes are believed to be growing.

Lake Kivu, 485 m deep, covers 2,400 sq km. Its surface elevation is 1,462 m.

The project is designed to overcome a severe electricity shortage, cut deforestation, and reduce the risk of an uncontrolled release of the lake's gas, the company said.

The government placed in operation a 4 Mw pilot plant in November 2008 that is feeding electricity to the national grid, ContourGlobal said.

### IOSC JV to boost oil production in Iraq

Mesopotamia Petroleum Co. Ltd. (MPC) has signed an agreement with Iraqi state-owned Iraqi Drilling Co. (IDC) to form a new joint venture focusing on increasing oil and gas production in Iraq.

"This is the Iraqi ministry of oil's first joint venture agreement of its type signed with a foreign company since the fall of the regime of Saddam Hussein in 2003," said MPC.

The company's name will be Iraqi Oil Services Co. LLC (IOSC), which will drill several wells for the nation's oil companies and international operations. On a conservative basis, these are expected to yield 5,000 b/d/well. About 60 wells/year are to be drilled around Basra as soon as possible, according to IDC.

In 2008 Iraq produced 2 million b/d, which the ministry is eager to boost to 3 million b/d as soon as possible and to 4.4 million b/d within the next 4 years. Iraq wants to achieve 6 million b/d of production by 2013.

"The parties to the joint venture intend to invest a total of $400 million to enable [IOSC] to purchase and operate 12 new drilling rigs and for provision of logistical support and working capital in order to deliver state-of-the-art performance in its operations," MPC said. IOSC also wants to improve local Iraqi expertise and integrated drilling technology.

IOSC is owned on a 51-49 basis by IDC and MPC respectively. MPC was founded by Ramco Energy PLC and Midmar Energy Ltd.

Idriss Al-Yassiri, director general of IDC, said IOSC had great potential inside and outside of Iraq.

Steve Remp, executive chairman of MPC, added that IOSC's longer-term ambition is to emerge as a partner with Western oil consortia in future field development projects.

This initiative builds on a wave of deals Iraq has signed to encourage investment and boost oil production, such as the $3.55 billion reconstruction agreement with SK Corp. (OGJ Online, Feb. 24, 2009) and an upgrade of its oil export terminal (OGJ Online, Feb. 20, 2009). ✦

## Processing — *Quick Takes*

### Pertamina renews refinery upgrade plan

Indonesia's state-owned PT Pertamina, renewing interest in an earlier plan, has signed a memorandum of understanding with Dubai-based Star Petro Energy (ETA Group) and Japan's Itochu Corp. to upgrade the country's 260,000 b/d refinery at Balikpapan in East Kalimantan.

"By signing the memorandum of commitment, Pertamina and those companies will hold further talks on upgrading Balikpapan refinery," company spokesman Anang Noor said of the signing, which took place at the World Islamic Economic Forum in Jakarta.

Karen Agustiawan, Pertamina president director, expressed hope that negotiations with ETA Group and Itochu would be concluded soon so that the project could be started on time.

State Enterprise Minister Sofyan Djalil, who said that negotiations with the two firms are continuing, estimated the venture as worth up to $1.7 billion. "It is still a tentative figure," he said, adding, "We still have to explore the actual price."

Pertamina has previously said it wanted to boost capacity at the Balikpapan refinery, which has two crude distillation units with respective capacities of 200,000 b/d and 60,000 b/d.

Pertamina said it wanted to increase total capacity to 280,000 b/d, switch from sweet crude to cheaper sour crude, and add a 50,000 b/d cracking unit to process heavy residue into gasoline and petrochemical products.

In October 2008, Pertamina set up a joint venture with Itochu and ETA Star to revamp the Balikpapan refinery. Pertamina processing director Rukmi Hadihartini said, "Each company's stake is yet to be decided" and that a project feasibility study was "expected to be ready in January 2009."

In January, however, Pertamina cancelled plans for expansions at two of its largest refineries—Cilacap in Central Java and the Balikpapan facility—due to the economic crisis and low oil prices.

At the time, Pertamina President and Director Ari Soemarno said the expansion plans could continue once the market stabilized, adding that the contractors—Japan's Mitsui and Toyo engineering corporations and South Korea's SK Corp.—were unwilling to provide quotes for services because of the volatile oil market.

Neither Pertamina nor the two other firms explained what brought about the change in policy since the decision in January not to proceed with the upgrade.

Last month, Pertamina, aiming to reduce fuel imports by boosting domestic supply, announced plans to construct two new refineries: one at Bojonegara, Banten, and another at Tuban, East Java. It also announced plans to upgrade a third facility at Balongen, West Java (OGJ Online, Feb. 15, 2009). ✦

## Transportation — *Quick Takes*

### Shell's Escravos pipeline suffers explosions

Shell Petroleum Development Co. (SPDC) reported that its trans-Escravos oil pipeline in Nigeria's Delta state has been breached in three places.

A company spokesperson told OGJ that it had shut-in oil installations in the Niger Delta to minimize potential damage to the environment. No details were given on how much had been lost at the pipeline.

"It was first reported on [Feb. 28] and confirmed during an assessment on the ground; the authorities have been notified," she said.

There have been explosions on the 24-in. line, which transports oil from the fields in the western Niger Delta to the Escravos export terminal.

SPDC is carrying out an investigation with the authorities and local communities to confirm the cause and the extent of the damage. "The incident was first reported by surveillance personnel on [Feb. 28]," she added.

The company declined to say how long the investigation would take or when the pipeline would be restored.

### Vietnam proceeds with expansion of tanker fleet

Vietnam's Dung Quat Ship Building Co., based in the central province of Quang Ngai, has held a keel-laying ceremony for a long-planned 105,000-tonne Aframax oil tanker.

The 244-m tanker, which is scheduled to be completed during third-quarter 2010, is one of three new ships that will be placed in the service of Vietnam's newly built 140,000-b/d Dung Quat refinery.

In June the Dung Quat refinery also is scheduled to receive a second Aframax oil tanker, slightly smaller at 104,000 tonnes, from Dung Quat Shipping Industry Co.

The two ships appear to be part of a larger 3-ship plan worked out by the Vietnamese government last year to ensure adequate shipping for the new refinery, as well as others under construction or in the planning stage.

Last December Petrovietnam's shipping arm PV Trans said it planned to invest as much as $3 billion altogether over the next 7 years to upgrade its crude and oil product tanker fleet to meet demand from Vietnam's refineries.

At the moment, the Dung Quat facility is the country's only refinery, but Vietnam has set a target to have at least three major refineries by 2013 as part of efforts to reduce product imports.

The Ho Chi Minh City-based company also said it aims to expand its businesses to operating floating storage and offloading vessels for Vietnam's oil producers.

A week before making that announcement, PV Trans secured a $175 million loan from a group of foreign banks led by Citigroup to purchase three 80,000-120,000-tonne Aframax tankers to transport oil for the Dung Quat plant.

In addition to Citigroup, lenders include Calyon Corporate & Investment Bank, Fortis Bank, and Societe Generale, while the 13-year loan was guaranteed by Nippon Export Investment Insurance and Petrovietnam.

In February 2008, ahead of the $175 million loan facility, the Dung Quat Ship Building Co. said it had imported nearly all the steel and other building materials needed to build the three Aframax oil tankers.

At the time, Dung Quat Ship Building Co. General Director Cao Thanh Dong, said each of the three oil tankers would likely cost more than $60 million. ✦

# Calendar

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

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## 2009

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Doha Natural Gas Conference & Exhibition, Doha, e-mail: gascon@qp.com.qa, website: www.dohagascon.com.qa. 9-12.

ARTC Annual Meeting, Kuala Lumpur, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 10-12.

European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 10-12.

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 10-12.

Pipeline Simulation Interest Group (PSIG) Meeting, Galveston, Tex., + 966 3 873 0139, + 966 3 873 7886 (fax), e-mail: info@psig.org, website: www.psig.org. 12-15.

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

Purvin & Gertz Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 17-18.

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

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

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

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952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

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

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

Offshore Mediterranean Conference & Exhibition (OMC), Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc2009.it. 25-27.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 29-31.

Petroleum Geology Conference, London, +44 (0)20 7434 9944, +44 (0)20 7494 0579 (fax), e-mail: georgina.worrall@geolsoc.org.uk, website: www.geolsoc.org.uk. Mar. 30-Apr. 2.

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 1.

Offshore Asia/Multiphase Pumping & Technologies Conference & Exhibition, Bangkok, 918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOA@pennwell.com, website: www.offshoreasiaevent.com. Mar. 31-Apr. 2.

## APRIL

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-3.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-8.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 7-8.

ATYRAU Regional Oil & Gas Exhibition & OilTech Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 7-9.

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 14-16.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 16.

Middle East Petroleum & Gas Conference, Dubai, 65 6338 0064, 65 6338 4090 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 19-21.

ERTC Coking & Gasification Conference, Budapest, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Hannover Messe Pipeline Technology Conference, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), website: www.hannovermesse.de. 20-24.

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

API Pipeline Conference, Fort Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-22.

Pipeline Transport Conference & Exhibition, Moscow, +43 1 230 85 35 33, website: www.expopipeline.com. 21-23.

# Danton's rising

*Uchenna Izundu*
*International Editor*

Shipwrecks have always had an ethereal quality. But there is also excitement associated with them, despite the tragedy of the sinking, because of the possibility of discovering hidden treasure.

As a young child this editor loved the Steven Spielberg film, 'The Goonies,' because it stimulated a longing for similar adventures with hopes of discovering gold coins in weathered old trunks—without the bad guys.

Divers and explorers often are amazed and mystified by the haunting beauty of ships lying on the seabed, as they offer a snapshot of maritime technology history.

Discovery of sunken ships by companies working in the oil and gas industry is gratifying, providing good stories for an industry currently sinking in a downward spiral of its own.

## The Danton shipwreck

Fugro NV, which provides specialist technical services for investigating the earth's surface, discovered the French naval vessel Danton, 35 km southwest of Sardinia, using its survey technology. Danton was one of the largest vessels of her era, and the find in 1,000 m of water holds international historical, cultural, and environmental interest, as the vessel is in remarkably good condition.

It also lies right on the route of the proposed Galsi pipeline, which, at 2,824 m below the sea, will be the deepest pipeline in the Mediterranean.

The Galsi company, which plans to deliver 8 billion cu m/year of Algerian gas to Sardinia by 2012, is rerouting the 850-km pipeline 300 m to the southeast because of the Danton wreck.

Danton was 146.6 m in length and could reach a speed of 19 knots. It was heavily armored with 32 cannons and two torpedo tubes.

The ship was launched in 1909 and was sunk in March 1917 with 296 individuals recorded as dead or missing. As many as 800 survived, mainly on rafts. Danton had set sail with 946 officers and sailors and 155 passengers—sailors returning to their allocated postings.

Two torpedoes in quick succession from the German submarine U 64 sank the battleship accompanying the French ship, and the Danton could not defend herself. The ship was unaware of the submarine threat until it was too late, and the ship's artillery could not open fire because no target could be identified.

As the electrics failed, the lifeboats couldn't be dismantled. Rafts and wood stored on the bridge were thrown into the sea. Naval historians recorded that the Danton's Captain Delage shouted, "Vive la France" with his officers three times as the crisis erupted; he went down with the ship. It took 30-35 minutes for the Danton to fall to the bottom of the sea.

## Nord Stream's challenge

This is not the first time that such unexpected discoveries have disrupted the planning of gas pipelines; the Baltic Sea is particularly cluttered.

Nord Stream AG, which will send up to 55 billion cu m/year of Russian gas to Germany via pipeline under the Baltic Sea, will raise a shipwreck off the coast of the German island Rugen early this summer, a company spokesman told OGJ. Nord Stream will provide a 60 m corridor to lay its 1,200 km pipeline, which is scheduled to start operations in 2011.

The discovered vessel, at 12.8 m long by 3.5 m wide, is much smaller than Danton; yet it has archaeological importance. It will be transferred to a remote gravel lake where it will join another three ships. Nord Stream will pay all salvage and transport costs.

This ship was part of a 980 m defensive barrier that the Swedish navy set up in the Bay of Greifswald to prevent enemy fleets from entering during the Great Northern War in 1715.

## Explosives on the route

It is important to preserve these relics, but the Baltic Sea is a particular headache to Nord Stream. Not only do 100,000 tonnes of unexploded World War II ammunition lie scattered along the route, but the German navy is concerned that one of its live shells might hit the pipeline and set off an explosion during Baltic exercises, according to the organization Managing Cultural Heritage Underwater.

Furthermore, ecologists worried about the effects on fish breeding grounds are protesting. Swedish environmentalists' fears and its diplomatic concerns about how Russia will increase its military presence in the Baltic Sea to protect the pipeline raise serious questions as to whether Nord Stream can secure permits to meet its start-up date on time. ✦

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Editorial

# Oppose cap-and-trade

That oil and gas companies differ over political issues is nothing new and usually constructive. Sometimes, however, unanimity can be helpful. A looming decision on climate change presents such an occasion.

The question here is not whether response is in order. Political realities make that question moot. A response will happen, probably soon. It probably will cap emissions of greenhouse gases and allow trading of emission allowances. Some oil and gas companies, aligning themselves with President Barack Obama and congressional leaders, favor that structure. Others prefer a direct tax on carbon emissions.

Companies in the latter camp are right. Others should join them, even if doing so requires reversals of stated positions.

## The appeal

The cap-and-trade approach has two characteristics that appeal to the companies that support it. Unlike a carbon tax, it starts with a specific target for emission cuts. And it uses market mechanisms for the trading of emissions allowances.

This page has long argued that reasons to favor a cap-and-trade system look better in theory than they can be in practice (OGJ, Dec. 15, 2003, p. 17). While a numerical objective has the buttoned-down feel of scientific management, any target with reasonable hope for enactment would be irrelevant to the real goal, which is to ameliorate atmospheric warming. The staunchest supporters of aggressive warming responses concede that all cuts under discussion can have, at best, minuscule effect on global average temperature and that the real hope is simply to take a first step. A carbon tax can achieve that.

Furthermore, any resemblance cap-and-trade frameworks bear to genuine markets ends with the word "trade." The government will strongly influence if not set prices of emission allowances. It will determine key trading conditions, such as the banking of allowances and the availability and geographic extent of emission offsets. The supposed market for emission allowances thus will be a creature of politics, eternally subject to influence-peddling and vulnerable to corruption.

The biggest problem with the cap-and-trade approach, however, is its dependence for support on political deceit. Like any other imposed reduction in emissions of greenhouse gases, cap-and-trade will raise the costs of using fossil energy. To have any effect, it must punish consumers enough to make them cut their use of fossil energy. Trading of emission allowances can't dissipate the pain. A new study by Bryan Buckley and Sergey Mityakov of Clemson University examines seven assessments of the cap-and-trade legislation most like Obama's proposal and concludes mitigation costs will be "huge." Those inescapable costs, imposed by government, will have the effect—but not the appearance—of a tax.

Yet politicians make full use of the illusion that cap-and-trade means someone other than consumers bears the costs. Obama wrapped himself in this shameful camouflage when he promised not to raise income taxes by a "single dime" except on the wealthy in a budget proposal that assumes "climate revenues" through 2019 totaling $646 billion. This money won't come from companies. It will come from consumers of fossil energy and of products that use fossil energy in their manufacture. It will hurt like any new tax.

Oil and gas companies should recoil from political witchcraft of this type. They should be their customers' strongest advocates, and their customers need a clear view of what's about to happen to them. Such a view can come only from a carbon tax.

## Avoiding deception

The avoidance of deception should be compelling by itself. But oil and gas companies have a practical reason to do what's right. Under any method of cutting greenhouse gas emissions, the costs to consumers of hydrocarbon energy must rise painfully. A carbon tax illuminates the source of the pain; cap-and-trade obscures it. If the reasons are obscure when emission abatement raises fuel prices, the oil industry will fall subject to a new round of public scorn, and politicians will exploit the tantrum to dodge their own responsibility.

It may be too late to prevent enactment of a cap-and-trade system. It's not too late for the oil and gas industry to disengage from the fraud. ✦

# Is it time for Gazprom to hit the reset button?

**Lucian Pugliaresi**
**Ben Montalbano**
**Saltanat Berdikeeva**
*Energy Policy Research Foundation (EPRINC)*
*Washington, DC*


The Russian-Ukrainian "gas war" that took place for 20 days in January and the disruption in December 2005 are part of a long-running struggle between Ukraine and Russia over pricing and transit fees.[1]

The latest confrontation is the most recent in a long line of disputes, not only with Ukraine but also with Belarus, a smaller but important transit point for Russian gas moving to European markets. These pricing and delivery commitment disagreements have been an ongoing feature of Russian relations with both countries since the fall of the Soviet Union.

The most recent dispute has heightened European concerns over dependence on gas supplies from Russia. The European Union's foreign policy chief, Javier Solana, said Europe has paid a heavy price because of the disruption in gas supplies and would review its energy relations with Russia and Ukraine as a result. He added that efforts to further diversify energy sources would move to the top of the EU's agenda.

Ironically, Europe's initial interest in gaining access to Russian gas supplies in the 1970s was the result of concerns over excessive reliance on oil imports from Organization of Petroleum Exporting Countries.[2]

Diversification away from Russian gas has been a major theme of European energy security policy over the last 20 years, although it has not necessarily been faithfully implemented. Europe gets about half of its gas imports from Russia, but dependence varies widely throughout the EU.

The view that "excessive" dependence on Russian gas would place Europe in a vulnerable position has also been a central theme in US foreign policy, which has encouraged Europeans to seek alternatives to Russian gas through greater production from the North Sea, imports of LNG, use of alternative fuels, and direct pipeline links to gas reserves in Central Asia.

Considering the realities of pricing and transportation costs in the European gas market, it is clear that buyers and transit partners, as well as Gazprom, bring leverage to the markets. Russia and the transit partners, for example, would suffer large and long-term losses if European customers diversified away from Russian gas. Russia's more accessible and near-term gas production is closer to Europe than any major alternative market. Russia and Europe are bound by geography, and moving gas to Asian markets or exporting it globally as LNG would impose higher costs on Gazprom and lower wellhead values.

At a recent presentation in London, Gazprom admitted that the Nord Stream and South Stream pipelines were meant to augment export supply flexibility rather than to increase volumes, which would put additional financial pressures on the already stretched state budget.[3] From the perspective of transportation economics, Ukraine and Belarus are the low-cost routes for moving Russian gas to the European continent, a fact well understood by both transit countries (see map, OGJ Feb. 19, 2007, p. 18).

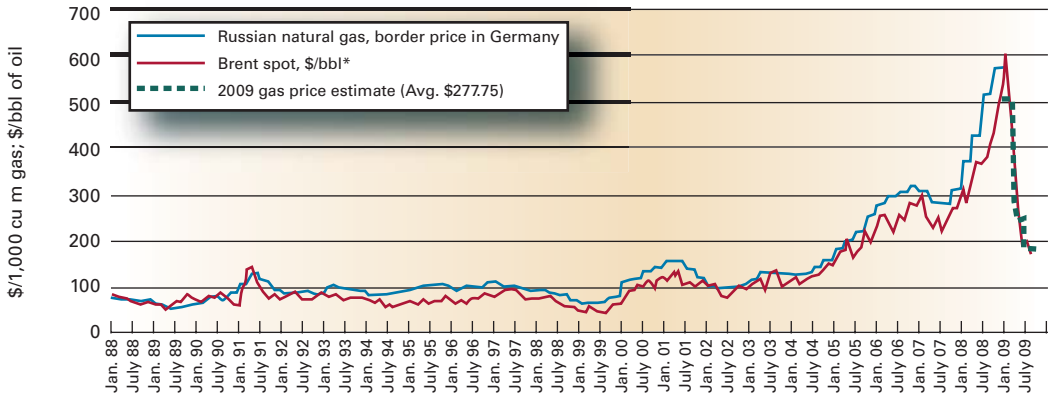
## Running toward Gazprom?

In light of these circumstances, and given the constrained financial environment in a low-cost oil and gas market, a more effective strategy for Europe would be to run toward Gazprom

rather than away from it. European governments and natural gas companies should revisit the concept of a Western Europe-owned and operated consortium to assume oversight of the pipelines and in exchange offer both Ukraine and Belarus longer-term, stable revenues coupled with assistance in adjusting to a world of post-Soviet energy prices.[4]

## Russian gas vs. Brent crude oil prices

Fig. 1




*Pushed forward 6 months.
Sources: IMF data, EIA data, EPRINC calculations

Transit operations would become much more transparent, possibly requiring somewhat higher transit fees to improve the integrity of the transportation system and at the same time move the entire delivery system to a less risky profile—one that could better address both technical considerations and politics.

Although this is not the first time such a proposal has been made, recent delivery disruptions from Russia combined with deteriorating financial circumstances among all key participants in the gas market could bring the relevant parties to the table to rethink the existing delivery arrangements. With regard to the West's relationship with Gazprom, this may be a propitious time to "hit the reset button."

### Gazprom: a price taker?

Although the European gas market historically has been dominated by state companies and a lack of transparency, the market has been open to more internal competition in recent years. Although not a hard and fast rule, gas prices are generally set by the cost of alternative fuels.

In the US, where gas has virtually penetrated the entire fuel oil market, gas competes head to head with coal and even higher-priced gas. In recent years, gas prices in the US have decoupled from oil prices, and there is growing evidence that this may be a long-term trend. In Europe, the price of gas is set by the price of oil.

As shown in Fig. 1—where the price of Brent has been pushed forward by 6 months to account for provisions in Russian gas sales contracts with Europe and multiplied by 4—the relationship between European gas prices and Brent prices has been relatively stable for over 20 years.

As a point of reference Fig. 2 shows the price of Russian gas at the German border, Henry Hub prices in the US, and delivered prices to US residential customers. Note the massive decoupling of gas prices and oil prices in the US market beginning in 2007.

While gas prices in the US have fluctuated in response to periodic supply and delivery constraints, such as cold snaps in the Northeast or hurricanes, the European market, dominated by the ready availability of fuel oil as a substitute to gas, has maintained a stable pricing relationship between the two fuels. Although Gazprom may be able to exercise some monopoly pricing in specific markets, the price history does not support a consistent and long-term capability to do so.

### Low oil price impact

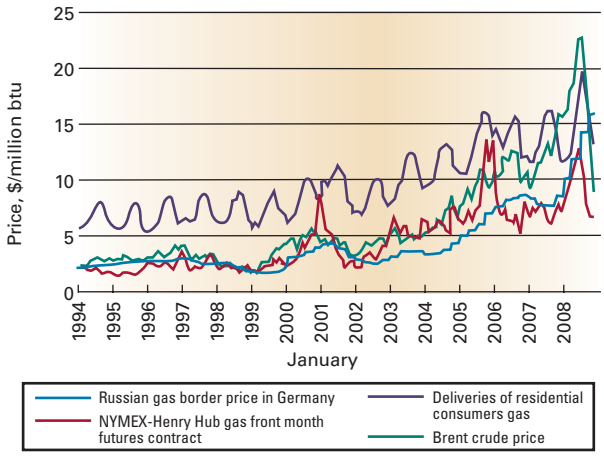
The collapse in oil prices in fall 2008 and declining economic activity throughout Europe will show up in lower gas prices and lower sales throughout 2009 along with lower revenues (Fig. 3). In 2008 Gazprom's gas exports to Western Europe averaged a record $409/1,000 cu m (Mcm), according to the company. With the collapse of oil prices beginning in July 2008, Gazprom will be charging lower prices to Europe in 2009—estimated by the company to be $280/Mcm, some 32% less than the 2008 average (Fig. 4). According to a recent presentation to investors, Gazprom said its exports to Europe may decline 5% in 2009 to 170 billion cu m (bcm) from 179 bcm in 2008 and the average price will drop as stated.[5] These figures would reduce European export revenues by about $26 billion, or 35%.

Note that Gazprom's price estimate aligns with EPRINC's estimate in Fig. 1 based on Brent crude. Although the Russian government is raising the regulated price of domestic gas by 20%, which will increase revenues by roughly $2.5 billion, it is hardly enough to make up for the $26 billion decline in European export revenues.

Exports to the Former Soviet Union (FSU) states will also command higher prices than in 2008. Russia historically

## RUSSIAN EXPORT VS. US GAS PRICES

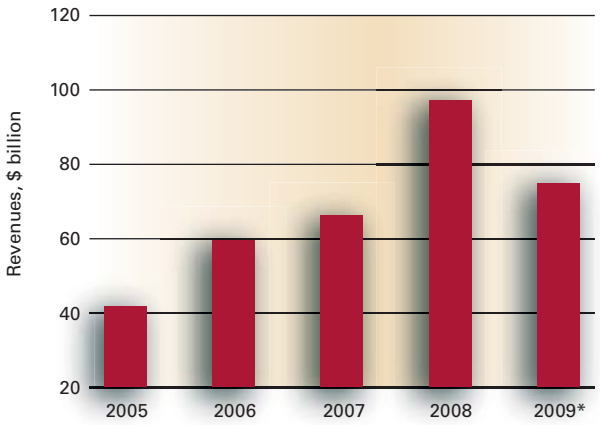
Fig. 2




Sources: IMF, EIA, EPRINC calculations

## GAZPROM'S GAS REVENUE: DOMESTIC AND FOREIGN SALES

Fig. 3




*Estimate.
Sources: Gazprom data, EPRINC calculations

has sold gas to the FSU at discounted prices but has begun to move the FSU to European market pricing. However, the increase is not large enough to cushion the fall in revenues from Europe and may be compounded by lower volume sales in 2009.

Across all three consumer groups, expect revenues to drop by about $22 billion compared with 2008. This number will change very little unless oil moves from $40/bbl between March and June.

### Lower gas price effects

The recent collapse in energy prices, global economic crisis, and gas dispute with Ukraine have brought about serious financial setbacks to both Gazprom and the Russian government, which is heavily dependent on revenues from hydrocarbon exports. Each of these is partially responsible for the 76% decline in Gazprom's stock price during 2008.

The most recent gas cutoff to Europe has imposed new financial limitations on Gazprom with a loss of well over $1.1 billion in direct revenues for the 20 days in January 2009, in which gas flows were halted to Europe.

Financial constraints resulting from the global economic downturn, combined with the collapse in gas prices, are likely to hinder Gazprom's ability to maintain and grow production in existing fields and fund many of its planned investment projects.

An analysis of Gazprom's current financial standing presents genuine constraints to future growth. As shown in Fig. 4, projected lower gas prices in the European market in 2009 will further diminish its revenue, which will lower state revenue. The Kremlin owns 50.002% of Gazprom through various companies and relies on Gazprom for both its tax base— the company pays taxes equivalent to about 20% of the Russian Federation's annual budget—and subsidized gas. The state's dependence on the gas company implies that it will continue to provide financial assistance to Gazprom but may find it more difficult to do so than it had expected.

The government has been spending billions of dollars from its reserves to bail out industrial companies and banks and to prop up the ruble since the economic crisis hit. Meanwhile, revenues from mineral and hydrocarbon exports have dried up. Covering the monopoly's current projects and expansion plans, which require massive financial commitments, will not be an easy task.

### Torn: projects vs. debt

Gazprom is a giant torn between expensive projects and debt. Its revenue woes are compounded by billions of dollars of debt—much of it due in 2009—and expensive projects necessary to maintain and grow production. The company has stated that it will maintain 2009 spending as planned but that long-term projects will have to be prioritized.[6] Gazprom approved its 2009 investment program amounting to 920.4 billion rubles ($26.3 billion), much higher than the 2008 budget of 821.7 billion rubles ($23.4 billion). Of that amount, 699.9 billion rubles is budgeted for capital expenditures and 220.6 billion rubles for long-term financial investments.[7]

Recent developments suggest that Gazprom may be reevaluating its investment plans after first-quarter 2009 as oil prices remain lower than expected.[8]

Gazprom is at a point where it must select projects carefully. Many of its

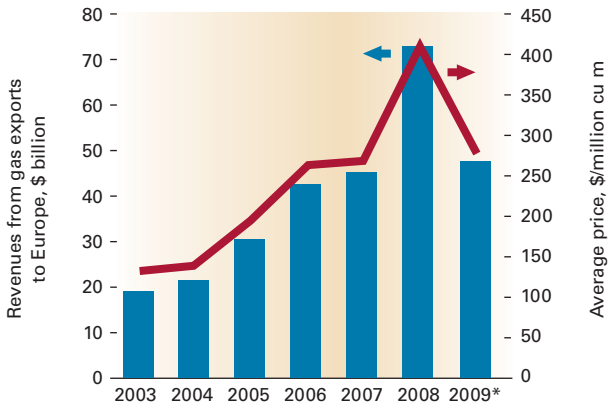
## GAZPROM PROPOSED PIPELINE PROJECTS

Table 1

| Planned pipeline | Estimated cost, $billion | Design capacity, billion cu m | Planned completion |
|---|---|---|---|
| Nord Stream | 11.64 | 55 | 2011 |
| South Stream | 27.6-35 | 31-47 | 2013 |
| Nabucco | 11.5 | 31 | 2013-14 |

## GAZPROM REVENUES DECLINE WITH LOWER OIL, GAS PRICES

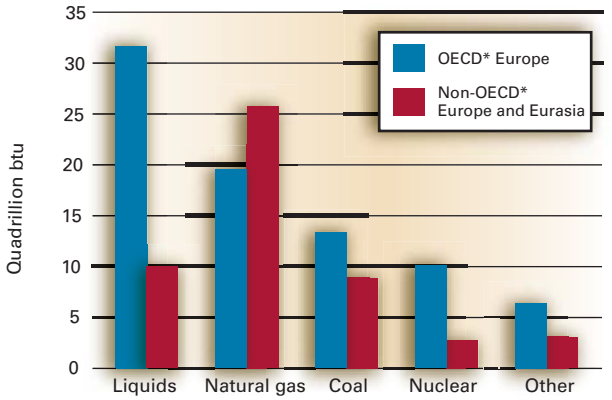
Fig. 4




*Estimate.
Sources: Gazprom data, EPRINC calculations

## EUROPE'S ENERGY COMPOSITION

Fig. 5




*Organization for Economic Cooperation and Development.
Source: EIA 2005 data

fields in western Siberia, mostly commissioned during the Soviet era, are in decline, putting promises of future production at risk. These concerns are forcing Gazprom to develop riskier plays such as Shtokman in the Barents Sea.

Gazprom also has plans for further development of Yamal in Northern Siberia and two elaborate pipeline projects, Nord Stream and South Stream, both of which circumvent Ukraine. Officials have remained confident that the company's main projects, namely Shtokman, Yamal, and Nord Stream, will continue as planned. There is concern, however, as to whether Gazprom can simultaneously carry out these ambitious projects as revenues and demand decline and large amounts of debt come due this year.

Shtokman is a gas field containing an estimated 3.8 trillion cu m (tcm) of gas. It is expected to begin producing gas in 2013 at the earliest, though development has yet to begin and Gazprom's minority partners in the project, Total and StatoilHydro, have yet to finalize investment plans. Initial development is expected to cost $12-20 billion and could grow more expensive over time. It is planned as a feeder field for Nord Stream, which if completed in 2011 will take gas from Russia directly to Germany under the Baltic Sea.

The head of Shtokman Development Co. said in December 2008 that nearly 70% of Shtokman will have to be financed and that a minimum price of $50-60/bbl for oil is required to make the project feasible.[9] This implies a minimum required price of $225-300/Mcm for gas from Stokman, whereas current production from Soviet era fields has an average cost of under $10/Mcm.

The Yamal peninsula, crucial to Gazprom's future, is scheduled to begin


producing gas in 2011. Its largest field, Bovanenkovo, is estimated to contain 4.7 tcm of gas, and the company says production will eventually reach 140 bcm/year. A 1,100 km westbound pipeline begun in 2008 will connect Bovanenkovo to Gazprom's Ukhta hub, which will allow for exports to Europe via the existing Yamal-Europe pipeline through Belarus.[10] In all, the peninsula contains at least 16 tcm of gas, according to Gazprom's estimates.

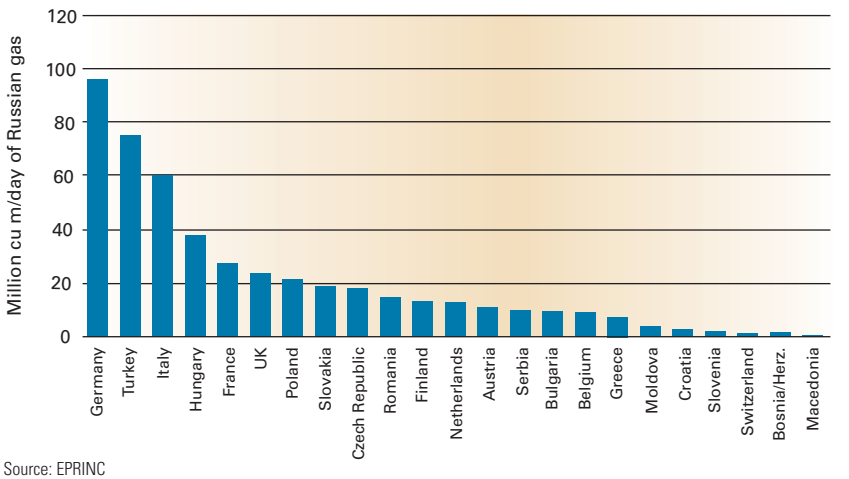
The development of the fields in the Yamal peninsula may cost upwards of $100 billion, with Bovanenkovo alone costing $60 billion. Between Yamal, Stokhman, Nord Stream, and South Stream, Gazprom is planning projects with a combined cost of around $120 billion, most of which it is likely responsible for, with planned completion dates of either 2011 or 2013, depending on the project. Ground has not been broken on Shtokman and South Stream, and the projects have a level of technical difficulty Gazprom has not had to tackle in its Soviet era fields. Gazprom has laid out extremely ambitious development plans. It appears as if the company has erred on the side of optimism, as timely completion of any one project will be very difficult given current economic factors and the lack of progress made on projects thus far.

### Debt, devalued ruble

If massive revenue declines and exorbitant project costs are not enough to make the Kremlin anxious about Gazprom's well-being, there is the issue of its debt. The company currently carries about $42 billion in debt and is obligated to make payments of about $10 billion in 2009.[11,12] The company borrowed heavily to acquire energy companies and make acquisitions often regarded as politically motivated, such as Sakhalin II and Beltransgaz,

## EUROPEAN CONSUMERS OF RUSSIAN GAS

Fig. 6




Source: EPRINC

among others.

Many saw the acquisitions as part of a renationalization effort led by the Kremlin. Those acquisitions and others like it, such as Sibneft, along with the need to finance parts of projects, caused Gazprom to triple the value of liabilities on its balance sheet during 2002-07.[13]

Gazprom's debt will certainly impede its ability to pay for projects in the future, particularly when payments of $10 billion are due the same year that revenues drop by $20 billion, and credit is needed to push grand expansion plans forward. The company has announced intentions to refinance portions of its debt. However, tight credit markets will make refinancing difficult, as the company has acknowledged.

The cost of Gaz Capital (Gazprom's financing vehicle) credit default swaps has risen to 981.1 basis points from 236 basis points over the past 6 months, meaning it now costs $981,100 to insure $10 million of Gazprom's debt for 5 years.[14] However, there are signs that the company can manage its debt. Uralsib said it believes Gazprom will be able to make its 2009 payments but noted that, because of the ruble's recent depreciation, the company may take currency losses as it converts rubles to pay debts denominated in foreign currencies such as the dollar and euro. And of course, the Kremlin cannot allow this apple to fall from the tree.

Gazprom has said that only 3% of its export revenue is being used as collateral for outstanding debt and that it will use additional export revenues as collateral in its effort to issue bonds worth 90 billion rubles ($2.6 billion) planned for later this year. The bond sale is to be used to refinance debt but will not occur until credit markets loosen.

Access to additional credit lines may be limited given legal constraints on Gazprom that prohibit the company from settling its debt through the sale of its strategic oil and gas assets. An alternative is to borrow directly from the Russian government.

### Bailout program

Russia has rolled out a $50 billion bailout program for the Russian economy, with $9 billion allocated for oil and gas corporations. Gazprom is hoping to receive $5.5 billion.[15] The company's well-being is critical to the health of Russia and its economy: Gas exports are responsible for about 10% of the country's gross domestic product, and its exports to Europe constituted about 15% of Russia's total export revenues in the first half of 2008.[16]

The Kremlin's ability to deliver gas to its citizens at a fraction of the cost of gas sold to Europe is a luxury afforded to it by Gazprom. The Kremlin can ill afford to lose that luxury and subject Russians to gas at European prices. And with tax payments equivalent to 20% of the federal budget, the company is a much needed revenue source.

The government cannot let Gazprom fail—not that failure is on the horizon—but its willingness and ability to finance Gazprom's planned capex is questionable as it bails out industries, banks, and the ruble and announces a large budget deficit for 2009 after years of budget surpluses.

Challenged with financial constraints, both Gazprom and the Russian government are expected to show more flexibility to attract foreign investors and look for strategies to secure access to markets. Cooperative ventures and even government-to-government initiatives that would lower operation costs, facilitate production growth, restore its relations with investors, and reduce investment risk are all likely to get a much harder look.

Gazprom's sizable 2009 investment program needs continuous cash flow, which will be a challenge to sustain in the face of low liquidity and sparse credit availability. Seeking financial contributions from various project partners would be appealing, as demonstrated by Gazprom's willingness (or perhaps need) to take on partners in Nord Stream and Shtokman.

### European market important

While oil remains a major source of energy in Europe's commercial and industrial sectors, the demand for gas is steadily rising to complement nuclear power and coal (Fig. 5). Although not

## UNIT COST OF RUSSIAN EXPORTS

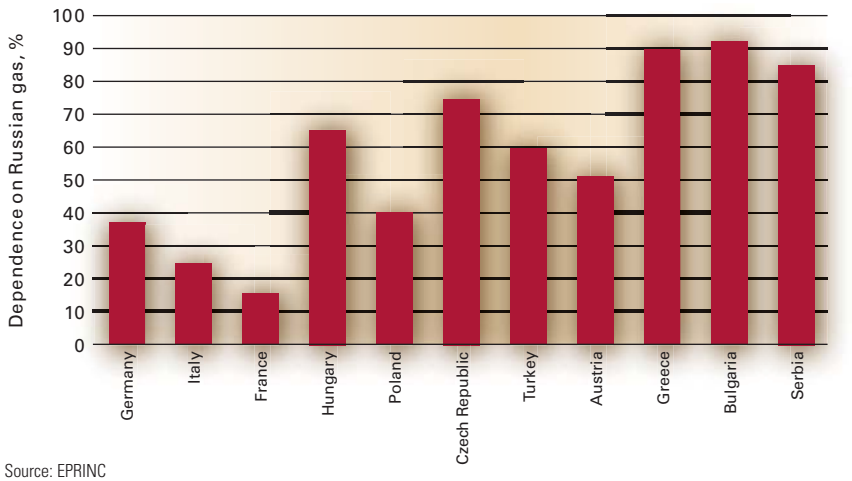
Table 2

| | Cost/1,000 cu m |
|---|---|
| Ukraine (transit fee) | [1]$22 |
| Nord Stream | [2]$10.58 |
| South Stream | [2]$29.36-37.23 |

[1] At current rate of $1.7/1,000 cu m/100 km. Does not include subsidized gas.
[2] Assumes full capacity over 20 years with no interest.
Sources: Reuters, official web site of the president of Ukraine, EPRINC calculations

EUROPEAN DEPENDENCE ON RUSSIAN GAS

Fig. 7




Source: EPRINC

everyone agrees, conventional wisdom is that by 2020 Europe is likely to see its gas consumption rise by 25%, with increasing supplies coming from abroad, as domestic production likely will fall by more than 40%.[17] Fig. 6 shows Russia's primary nondomestic gas customers.

Western Europe has limited gas reserves, mainly in the North Sea, and some argue that production is reaching or has reached its peak.[18] According to the European Committee on Economic Affairs and Development, "Germany, France, the Netherlands, Spain, and Italy are among the world's 10 largest importers of crude oil, while the same countries and Turkey are also among the 10 largest gas importers."[19]

Despite Gazprom's worsening financial situation and complex relations with downstream partners such as Ukraine, Russia has a commitment to meet 25% of Europe's gas needs. Russia exports roughly 465 million cu m/day to Europe, and 80% of that flows through Ukraine. Wealthy Western European nations generally exhibit less dependency on Russian gas than poorer, Eastern European nations (Fig. 7). That trend is reflected in Fig. 5, which shows that non-Organization for Economic Cooperation and Development (OECD) countries in Europe and Eurasia use more gas than OECD Europe but get less energy from all other types of fuel.

Much of the FSU still receives Russian gas at a subsidized rate, although Gazprom is moving prices to market rates, partly because it purchases 60 bcm/year of gas from Central Asia. That gas, which is then exported to Europe, is no longer accessible at prices well below market values. Central Asian producers have moved, or can threaten to move, their production to more lucrative markets (China, Nabucco).

In 2008 exports to Europe generated $73 billion in revenue for Gazprom, compared with domestic sales revenue of $37 billion and exports to the FSU of $14 billion. Even though Europe represents only about 30% of Gazprom's sales volume, it accounts for 60% of its revenues. In 2008 Russian customers paid about one eighth of the rate per thousand cubic meters as European importers paid.

As the European market is Gazprom's largest revenue source, it is perhaps as dependent on Europe in terms of market access and revenue as Europe is dependent on Gazprom. As EU Energy Commissioner Andris Piebalgs said: Gazprom exports most of its energy to Europe because Europe is a familiar market and the market economy where Russians know they "will get very good profits for their gas."[20] Gazprom saw record export revenues in 2008 for its gas as European gas prices topped $500/Mcm towards the end of 2008. However, with the rapid collapse of oil prices in the fall of 2008, the prices declined as well.

Recently, Alexander Medvedev, deputy chairman of Gazprom's management committee, announced that gas exports to Europe would be reduced if the economic decline persists and energy demand falls further.[21] Gazprom said it would wait until the end of the first quarter of 2009 before deciding on a cutback in exports if demand falls sufficiently in Europe.[22] The effects of the fall in production could be felt more sharply in the longer run, potentially leading the company to seek financial assistance from its foreign partners to develop new fields.

## The pipeline dilemma

Gazprom's potential obstacles in financing major projects do not end with development of upstream resources. The 55 bcm/year capacity Nord Stream pipeline, intended to connect Russia directly to Western Europe without transiting any Eastern European countries, would serve dual purposes. It would avoid Ukraine and would add capacity to the existing system if European demand increased and new supplies came online. It is already facing rising costs and delays, however. The Nord Stream consortium has elevated the cost of the originally 4-5-billion-euro pipeline to 8 billion euros ($11.64 billion).

Complex negotiations with Baltic littoral states to get permits to build the undersea pipeline have further stalled the project. Similarly, the fate of the South Stream gas pipeline, which is planned to link Russia with Austria and Italy via a pipeline through the Black Sea, is beset with more delays and cost overruns. The project may cost over $31 billion, as opposed to the $20 billion announced in July 2008 by Russia's Energy Minister Sergei Shmatko. It also would carry a maximum of 47 bcm/year—8 bcm/year less than the planned Nord Stream. See Tables 1 and 2 for a breakdown of costs, capacities, and

completion dates.

Construction of the onshore portion of Nord Stream has begun, though not the tricky undersea portion, meaning Nord Stream has some momentum behind it, although perhaps not enough to see it through to completion, while South Stream has not left the planning phase, leading many to believe it is little more than a fantasy.

The latest Russia-Ukraine gas crisis has clearly encouraged Gazprom to move forward quickly with Nord Stream construction. While Nord Stream solves some problems by bypassing all existing transit states with the contentious pipeline disputes common in central and Eastern Europe, it also opens concerns that the project will bolster Russia's leverage in the region.

Once Nord Stream is up and running, least cost strategies for dispatching gas to the European continent may lead to the abandonment of transport volumes along established transit routes in favor of shipping gas through Nord Stream.[23]

Reliance on Nord Stream may create so-called network risks, i.e., it offers Gazprom the opportunity to deliver supplies to its western European customers while remaining in a position to curtail supplies to some of the gas-dependent Eastern European countries, particularly Poland. While this is a genuine concern, Russia has so far been reluctant to cut off customers paying market prices.

## Risks

Although Nord Stream appears to be moving forward, it does face some completion risks, both from cost overruns and from opposition from littoral states. Vladimir Milov from the Russian Institute of Energy Policy argues that the pipeline will cost at least $13 billion and is an ecologically dangerous construction that may not be financially justified.[24]

Russians have taken a large part of the financial risk and have already begun construction on their end and are putting various supply and service contracts in place. Even based on the higher construction cost estimates, Nord Stream should be able to operate within a cost structure competitive with existing transit costs for moving supplies through Belarus and Poland. Additionally, Europe is expected to see substantial growth in longer-term gas demand, and Nord Stream should handle the new volumes.

One big "if" with regards to Nord Stream is Shtokman field. Gazprom apparently is building Nord Stream with the intention of feeding it with Shtokman gas. As discussed earlier, ground has not yet been broken on Shtokman, and it is set to begin production 2 years after Nord Stream is scheduled to be completed in 2011, creating doubt about the viability of a 2013 start.

Whether or not Gazprom can afford development of Shtokman at the moment will further impact the viability of Nord Stream. If Gazprom can bring the two projects together in a relatively timely and economic manner, it could become a powerful asset for Gazprom.

Even before gas prices collapsed and the financial crises hit, Nord Stream was far from being a certainty; now it is even less so. Whether or not Nord Stream fulfills its objectives and becomes a cost-effective project, resolving the transit risks in Ukraine and Belarus will still generate substantial benefits to the producer, shippers, and consumers.

## European solution

As Gazprom faces rising costs of current production and expansion plans while its revenues are in sharp decline, Ukraine is in a position to extract "economic rent" in terms of higher transit fees, discounted gas, and stolen gas. The situation is inherently unstable because the alternative for Russia is to pay a very high price to go around Ukraine in the form of Nord Stream or South Stream.[25]

But Ukraine could potentially jeopardize its position and lose both its economic rent and political leverage if the Russians in fact go ahead with either gas line. In this environment, the Europeans have the opportunity to unite and step in to provide stability to the Russians and a reliable long-term commitment to the Ukrainians, who arguably have the most at risk. ✦

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References may be accessed at: www.eprinc.org/pdf/gazprom-timetoreset.pdf.

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# Russia-Ukraine gas confrontation raises major questions

**Nick Snow**
*Washington Editor*

The confrontation between Russia and Ukraine in January over natural gas raises questions not just for Europe, but also for the US, experts indicated at a recent seminar at the Heritage Foundation.

"Russia's energy influence extends all over the world, including the US. The importance of its gas is that its European customers are tied to the pipeline and can't replace supplies from elsewhere," said Marshall I. Goldman, emeritus professor of Russian Economics at Wellesley College and a senior scholar at the Davis Center for Russian Studies at Harvard University.

Edward C. Chow, a senior fellow in the energy and national security program at the Center for Strategic and International Studies, said the Russia-Ukraine gas confrontation was not surprising. The 10-year agreement that the two countries signed Jan. 19 will be lucky to survive 10 months, he predicted.

Jonathan Elkind, a senior fellow at the Brookings Institution's Foreign Policy Program and Energy Security Initiative, agreed. "It's a dynamic situation and it's not over yet. A key requirement of the Jan. 19 sales agreement is that Ukraine stay current on its payments. If it doesn't, then it starts paying on a month-ahead basis," he said.

Laslo Deak, political counselor from the European Commission's delegation to the US, said that Europe is trying to take a dispassionate view toward Russia, which is having a difficult time defining its relationship to Europe. He said Vladimir V. Putin, first as Russia's president and then as its prime minister, wanted to do this in terms of energy dependence. "The Soviet oil and gas structure simply provided an opportunity," Deak said.

## A lesson for the US

David W. Kreutzer, a senior policy analyst in energy economics at the Heritage Foundation, said an important lesson for the US is not to grow too dependent on imported natural gas as it pursues climate change reforms. Wider use of wind to generate electricity could make US gas imports grow to back up wind, which is intermittent, he said. "We need to be more careful. We're putting forth policies [that] ostensibly would make us more energy independent but could actually have the opposite effect," he warned.

Karen A. Harbert, president of the Institute for 21st Century Energy at the US Chamber of Commerce and a former assistant US energy secretary for policy and international affairs, said disagreements arise from differing energy security definitions, with the West seeking access to supplies and the East trying to control those supplies and their transmission.


She said the natural gas showdown between Russia and Ukraine reconfirmed that Europe needs to take the lead in addressing its heavy reliance on Russian gas. "It's important that the [European Union] speak with one voice. Russia will be part of Europe's gas future for some time," she indicated.

Ariel Cohen, a senior fellow in Russian and Eurasian studies and international energy security at the Heritage Foundation and the seminar's moderator, said European dependence on Russian gas is of strategic interest to the US. One reason is that it influences individual countries' policy decisions such as Germany's leading the opposition to expanding the North Atlantic Treaty Organization, he said.

Several in the group also said Ukraine needs to improve its internal energy operations. Cohen noted that the country uses as much gas as Germany, but its gross domestic product is only 10% the size of Germany's. Chow said Ukraine has become a major hydrocarbon transit country, through which most of Russia's oil and gas exports to Europe pass. "There has been no fundamental reform of its energy sector since the Orange Revolution 4 years ago, and the problem isn't going to fix itself," he said.

## Ukraine's internal challenges

Elkind suggested that with a presidential election on the horizon, Ukraine's domestic politics could produce calls for energy price subsidies to stimulate economic growth as it tries to keep import costs in check. He expressed hope the US would have a successively closer relationship with Ukraine, but added, "We don't really have a dog in this fight. There are limits to what we can do unless Ukraine takes a more proactive role.

"There's a great deal that the US and Europe can do, if there's unanimity, to help Ukraine make these hard choices. But there's very little we can do unless there's serious reform within Ukraine itself," Elkind maintained.

Harbert suggested Europe needs to take more of a lead, but this is undercut by individual countries making their own energy deals with Russia. "It's an economic as well as a political issue. There are huge sums of money involved.

The recent Russia-Ukraine contract was a marriage of convenience because Ukraine needed revenue and Russia was running out of storage and couldn't shut down production," she said.

Deak said the European Commission proposed an energy strategy in 2006, which it adopted last summer, that emphasizes diverse sources, diverse transmission lines, alternative energy sources, and energy efficiency, including a common energy grid within the EU. Special relationships between individual European countries and Russia aren't working, he continued, and Europe recognizes that the proposed Nabucco pipeline to move gas from Central Asia is desirable. "It's not the only solution to Europe's diversification problem. North Africa still has abundant gas supplies. So does Norway," he said.

EC President Jose Manuel Barroso recently visited Russia, Deak said. "Nothing consequential came out of the meeting, but the decision to take nine commissioners sent Russia a message that Europe will not be held hostage over energy in its relations with Russia," he said.

But Goldman warned that if there isn't more support from both suppliers and customers, alternative gas pipeline routes won't be used. "The Russians know how to play them off against each other because they say their pipelines are already up and running," he said. ✦

# Russian oil firms combat 'perfect storm' of grim events

**Judy R. Clark**
*Senior Associate Editor*

The Russian Federation's oil industry currently is facing a "perfect storm" of difficulties—with simultaneous, sudden low oil prices, high taxes and tariffs, the devaluation of the ruble, and the global financial crisis—according to Russian oil executives evaluating the outlook for Russian oil at a February CERAWeek presentation in Houston.

Russian tax reform is high on the list of priorities leading back to growth and profitability for oil companies, said Peter O'Brien, chief financial officer of OAO Rosneft. The price of oil fell so rapidly in the second half of 2008 that, under existing tax laws, profits were squeezed out in the fourth quarter, with "99% of the price of oil [going toward] the export duties, profits tax, and transportation duty, providing for a difficult operating budget," he said. "There wasn't much left with which to generate cash for operating expenses."

## Russia cuts production

"In addition to that, Russia experienced its first year of [oil] production decline in a decade," O'Brien added.

Russian oil production may continue to decline due to capital restrictions and to a deal Russia made last year with the Organization of Petroleum Exporting Countries. Andrei Gaidamaka, deputy vice-president of strategic development for OAO Lukoil, said Russia had been providing 50% of non-OPEC global oil production but agreed in 2008 to reduce production as part of efficient cooperation with OPEC.

The compound annual growth rate (CAGR) for 2009 is expected to be 1-2%, O'Brien said, "making the economics more difficult for us and our peers."

## New government policy

However, recent political developments in Russia, including the second election with changes in government in 2007 and the presidential election in March 2008 "bring a new and very much invigorated policy toward the energy industry and offshore industry as included in the various discussions on taxes," O'Brien said, along with the recognition of the "pain that the industry is going through." Russia is attempting to counteract the same financial downturn that other nations are experiencing, he added.

Some positive changes that have occurred in response were a reduction in the profits tax from 24% to 20%, and on Nov. 1, the export duty was reduced, O'Brien said. "This is huge progress…." However tax and transportation burdens are still high, he stressed, and "the multifold growth in natural monopoly tariffs doesn't leave much left to invest for the future."

Improved performance in downstream operations offset some of Rosneft's E&P and transportation costs, O'Brien said. "The company looks good, but it is getting difficult to maintain growth," he said. The potential is there, with resource potential of 3 million b/d of liquids. The company's implied CAGR is 16.4%, with costs averaging $2.49/bbl.

O'Brien said major elements to watch include the oil price in US dollars compared with the ruble, inflation following devaluation, and further tax improvements to reduce the industry's risk, he said.

Gaidamaka, speaking of "continuous growth in an improving macro environment," was more optimistic, saying market fundamentals support oil production at $50-80/bbl and that Lukoil "will be cash positive under any scenario."

While the ruble is weakening, oil prices are still comfortable and support earnings growth, he maintained, adding: "Downstream operations in Russia have become infinitely more profitable," with Lukoil's refining throughputs also up since 2006 and a 15% increase in the number of its filling stations. "We will not have any reduction in our growth prospects in retail because the company does have sufficient capital to fund them."

But, he said, "the company's most exciting growth right now is in natural gas."

During the next 8-9 years, Lukoil plans to produce 300,000 b/d of oil from the North Caspian Sea area, and he said the Y-K project in the Barents Sea has over half a billion bbl of reserves to be produced.

He also said the major portion of the company's operating expenses (88%) are based in rubles, which contributes to its cash flow by reducing capital costs and operating expenses in Russia. Lukoil also operates in nearly 40 other countries.

## Kudrin's scissors

The advantages of Russia's lower production costs, however, are offset by the taxes, duties, and tariffs, which the government sets, recalculating export duties every 2 months, said Boris Zilbermints, vice-president of exploration and production for Gazprom Neft, the oil subsidiary of OAO Gazprom.

However, "Minister Kudrin's scissors" [delayed revisions of high oil export duties following sharp reductions in oil prices]"caught up with the oil industry in the second half of 2008 when export taxes exceeded oil prices and revenues," he said.

The government's legislative changes as of Jan. 1, which reduced corporate income taxes and other taxes, "are substantial but still insufficient," Zilbermints agreed. "A lower tax burden would be totally offset by growing oil production," he stressed.

## Enormous reserves

The Russian state estimates that Russia has 30 billion tonnes of oil and 74 trillion cu m of gas reserves. BP PLC statistics put them at 11 billion tonnes of oil and 45 trillion cu m of gas. "Either way they are enormous," Zilbermints said. However, he said, they have mainly been explored and many are depleted, another 'storm' element. Furthermore, there have been no major discoveries in the former Soviet Union in the last few decades, he said. The States Reserves fund of 400 million bbl is intended for future generations—a "dog in the manger."

Russia, which has the reserves, is participating in joint ventures and partnerships with international oil companies, which have the technology, enabling Russian companies' technology acquisition and participation in overseas projects. Areas of expertise and cooperation include exploration, oil-gas condensate fields, offshore fields—especially in Arctic waters such as the Barents Sea—and fields with highly viscous oil, such as in western Siberia fields in which Chevron Corp. is participating on a JV basis.

## Developing talent

Another issue Russia must address is investment in talent and human capital. The shortage resulted from structural, economic, and demographic changes following the breakup of the Soviet Union. Although Russia's university system has expanded greatly, Zilbermints said, technical and vocational education has been neglected for years. Competition for talent leads to speculative demand and overpayment.

There are employee rotation difficulties for two reasons, he said: lack of tradition and willingness. "It is easy to get someone from Siberia to Moscow, but not vice-versa." He said the company is creating a talent pool and implementing new employee incentives. ✦

This article is the first of two parts addressing the challenges facing Russia's oil and gas industry. In Part 2, Grigory Vygon, director of economy and finance at the Russian Ministry of Natural Resources, will describe the fiscal and regulatory reforms planned and being implemented to stimulate private exploration and development of Russia's oil and gas reserves.

# Divisions form over oil, gas provisions in Obama budget

**Nick Snow**
*OGJ Washington Editor*

Sharp divisions have formed over the Obama administration's budgetary proposals to eliminate "oil and gas company preferences" worth an estimated $31.48 billion over 10 years and raise other taxes on the industry.

A budget that would eliminate tax mechanisms crucial to capital formation for drilling, such as expensing of intangible drilling costs (IDC), drew immediate criticism as "a devastating blow to the American oil and gas industry" from Independent Petroleum Association of America Pres. and Chief Executive Officer Barry Russell (OGJ Online, Feb. 26, 2009).

President Barack Obama on Feb. 26 unveiled the $3.6 trillion budget for the fiscal year beginning Oct. 1.

In addition to eliminating IDC expensing, the budget would repeal the manufacturers' tax deduction for oil and gas companies and the percentage depletion allowance, which is important to small independent producers.

The budget also would repeal the enhanced oil recovery credit, the marginal well tax credit, the deduction for tertiary injectants, and the passive loss exception for working interests in oil and gas properties.

It also would impose an excise tax on Gulf of Mexico production and would reduce royalty relief beginning in 2011. It also would increase the geological and geophysical amortization period for independent producers from 5 to 7 years.

Separately from the section on tax "preferences," the budget would charge producers user fees for processing permits to drill on federal lands and reform

royalties and adjust rates to increase revenue.

And it would reinstate the Superfund tax on refiners and petrochemical manufacturers, envisioning receipts beginning at $1.2 billion in 2011 and phasing up to $2.3 billion in 2019, totaling $17.2 billion in 2011-19.

Congress created the Superfund tax with the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) to fund cleanup of abandoned hazardous waste sites.

Superfund taxation authority expired in 1995. Since expiration in 2003 of a trust fund established by CERCLA and expanded by the Superfund Amendments and Reauthorization Act of 1986, Superfund activities have been funded by congressional appropriations from general revenues.

## New responses

National Petrochemical and Refiners Association Pres. Charles T. Drevna criticized elements of budget including repeal of the manufacturers' tax deduction for oil and gas companies.

Congress created the deduction for all US manufacturers when it passed the American Jobs Creation Act of 2004. Drevna said denying its use to refiners "would only weaken, not strengthen, our nation's energy security by stifling both the well and ability to increase domestic oil and gas production."

The manufacturers' deduction encourages refinery capacity expansions, he said. "With demand for gasoline continuing to grow each year, US refining capacity is already significantly strained despite multibillion-dollar reinvestments by the industry to expand it. Under normal economic circumstances, most refineries operate at more than 90% capacity throughout the year (except during maintenance season), which is significantly higher than the normal industrial average of about 75-80% of capacity."

Because US refiners compete in a global market, the manufacturing tax deduction helps them compete internationally and bolsters national energy security by reducing the need for oil product imports, he said.

Congressional energy leaders' responses to the budget's oil and gas tax provisions generally followed party lines.

US House Natural Resources Committee Chairman Nick J. Rahall (D-W. Va.) essentially welcomed them. "The president's proposal places a major emphasis on ensuring that taxpayers receive a fair return for the extraction of oil and gas resources on public lands and presses wealthy oil companies to diligently develop the leases they already possess on the Outer Continental Shelf," he said.

"Last Congress, I introduced legislation to reform the royalty collection program, encourage the diligent development of federal oil and gas leases, and require energy companies to pay their fair share for the use of public resources. I am heartened that the president's budget includes all of these initiatives and also correctly identifies our public lands as an immense potential resource for the development and deployment of domestic alternative energy," Rahall said.

## 'Punitive provisions'

But US Sen. Lisa Murkowski (R-Alas.), the Energy and Commerce Committee's ranking minority member, expressed concern not only about the billions of dollars of additional taxes, fees, and other expenses for oil and gas producers but also about so-called "Use it or lose it" requirements for federal lessees. "These punitive provisions will raise revenue for the federal government, but they won't increase the energy security of the United States," she said.

"This represents an attempt to drive the oil industry overseas through a combination of breaching past agreements the government has made with oil and gas producers and making future production more difficult and expensive. Instead of declaring war on the domestic production of conventional energy, as I believe the president's budget does, we need to focus on how we can use our abundant domestic resources of oil, natural gas, and coal in the cleanest, most environmentally friendly way possible for the sake of our nation's economy, our nation's security, and the world's environment," Murkowski said.

Sen. Mary L. Landrieu (D-La.), who is on the Energy and Natural Resources Committee, called the budget proposal "an honest and balanced blueprint for America's future" that "emphasizes high-return investments and makes significant strides in restoring fiscal responsibility and deficit reduction."

But she expressed concern about changes it would make in the oil and gas tax regime. "In these tough times, we must make sure that we do not disadvantage our domestic energy industry, which is critical to the nation's security, against foreign competitors. This industry provides good-paying jobs and plays a critical role in helping us reduce our dependence on foreign oil," Landrieu said.

After expressing his concerns about carbon cap-and-trade provisions of the president's proposed budget, Sen. James N. Inhofe (R-Okla.), the Environment and Public Works Committee's ranking minority member, said the budget's proposed oil and gas tax increases would potentially eliminate tens of thousands of domestic jobs in the industry, increase fuel costs for consumers, and make the nation even more dependent on foreign oil.

"In the United States, there are nearly 6 million Americans directly and indirectly employed as a result of the oil and gas industry. Tax increases of this magnitude will significantly curtail the operating budgets of all exploration and production companies, big and small. Every marginal well operator in the country should be gravely concerned that these proposals will force the premature plugging of low-production marginal wells. And, despite the rhetoric, America's oil companies are already paying taxes at the highest rates," he said.

### Nonindustry responses

Nonindustry groups also responded to the proposals.

Thomas J. Pyle, president of the Institute for Energy Research, said they were not economic development but "a surefire way to send America's businesses either to bankruptcy or overseas."

He said, "It's alarming enough that the administration's plan to balance its books relies on funds it hopes to receive from a policy it hopes to someday enact. But what's truly appalling is that it's attempting to sneak this huge stealth tax into the budget at a time when so many Americans are facing unprecedented economic constraints."

David Holt, president of the Houston-based Consumers Energy Alliance, said that while Obama's proposed budget takes unprecedented steps to develop new alternative energy sources, it also takes unprecedented steps to make producing affordable energy from traditional sources more difficult and expensive. "The realization of an alternative energy future will not be achieved by making a reliable energy present impossible. My fear is that a number of the provisions in this budget would do precisely that at precisely the wrong time for struggling consumers and a flagging economy," he said.

Environmental organizations expressed the opposite view. "Today's budget announcement makes clear that the oil and gas industry will not continue to enjoy a taxpayer-funded feast at the expense of America's public lands and waters," Wilderness Society Pres. Bill Meadows said. "Following his strong statement on climate when he addressed Congress on Tuesday night, the president today offered further confirmation that it's not business-as-usual in Washington when it comes to fighting global warming pollution."

Erich Pica, domestic programs director for Friends of the Earth, said, "The days of Big Oil earning record profits while feeding at the taxpayer trough are coming to an end. President Obama's decision to put an end to these giveaways is a huge victory for taxpayers and the planet." ✦

# State governors evaluate energy's role in economic strategies

**Nick Snow**
*Washington Editor*

US governors brought a wider than usual range of energy ideas to the 2009 winter meeting of the National Governors Association Feb. 21-23 in Washington as they grappled with a deepening recession.

In state-of-the-state addresses to their legislatures during January and February, some continued to embrace the development of alternative and renewable resources as their primary goal. Others cited falling revenues—as oil and gas production has declined—and ongoing efforts to increase supplies.

All expressed concerns about deep budget deficits. Several said they expect traditional, as well as future, energy sources to contribute as their states try to recover.

"When oil prices and state revenue are on the rise, as was the case, there's temptation to assume it'll go on rising forever, and to spend accordingly," said Alaska Gov. Sarah H. Palin (R) on Jan. 22. "Since prices fell, there may be an equal temptation to draw heavily on reserves or, for some, to be tempted to tap the permanent fund earnings or tax our hardworking families.

"No. With the budget, the aim is to keep our economy on a steady, confident course. The aim is, with discipline, [to] protect our reserves and promote economic growth," she continued.

Unless crude oil prices increase soon, however, Alaska is looking at a more than $1 billion revenue shortfall in 2009, Palin told her state's lawmakers. Spending will need to be cut where necessary, and it will take cooperation to see the state through this uncertain period, Palin said.

### Changing projections

Preparation of Wyoming's proposed 2009 budget was under way in July 2008 when crude oil prices approached $150/bbl and there was talk of more than $1 billion of revenue, according to Gov. Dave Freudenthal (D). By October, the projected revenue was $900 million based on a $75/bbl oil price, he said. Freudenthal added that he was not comfortable with those numbers and started planning on the basis of $440 million of revenue.

"Well, in a matter of less than 3 weeks from the time I submitted my budget, it became clear that that was not a safe number, and so in January you had a new set of budget projections of $259 million," he said in his Jan. 14 address to the state's legislators.

"So we arrive here with a little unease with regard to the quality of the projections. We also arrive here in the context of having had a set of expectations that were built up not only within this body and within the executive branch of government, but a set of expectations that were built up in the public and in the interest groups about what we were able to fund and what we might be able to do," Freudenthal said.

For the first time, many Cowboy State lawmakers will have to tell constituents "No, and maybe not for a long time," he went on. "But, before we conclude that the sky is falling, let's just take a brief look back. The year I was first elected in 2003, the projected number for the price of oil was $18/bbl. The price of oil in these current projections which we find so dismal is $40. In 2003 the projected price for natural gas was $2/Mcf. Today, in these projections we're operating on, it is

*Alaska Gov. Sarah H. Palin called the proposed natural gas pipeline to markets in the Lower 48 states her state's next major economic lifeline as she addressed legislators on Jan. 22. But she said she would also propose a smaller system to deliver gas to Alaskans.*

$3.75," the governor said.

Voters' faith in stable oil and gas markets has been severely tested, noted Arkansas Gov. Mike D. Beebe (D) on Jan. 13. "Oil prices skyrocketed in 2008, and we shook our heads—and sometimes our fists—at the record prices we paid for gasoline and diesel over the summer. Six months later, we are shaking our heads again as those same prices plummet to levels we thought would never return. However, we know that [gasoline] prices won't stay low, because oil-producing countries won't let them. [The Organization of Petroleum Exporting Countries] has already reduced supply in an effort to bring back higher prices and increase profits," Beebe said.

Americans and Arkansans "can change the game" by continuing to develop alternative and renewable energy sources, and by conserving energy and operating more efficiently, he told his state's lawmakers. "State government will lead by example, conserving both our natural resources and our tax dollars," Beebe said.

## New revenue source

Beebe also saw unconventional gas production as a possible new revenue source because the state sits amid the Fayetteville shale play.

"This year, we will see new revenue from the severance of this natural resource, money destined to improve our highways. The amount of revenue is tied to the price of gas, which has swung just as wildly as oil prices. Still, we will see tens of millions of dollars in new money for state and local roads. Additionally, this money will fund new resources for the Arkansas Department of Environmental Quality to regulate and monitor these drilling operations and safeguard our natural state," Beebe said.

Faced with a projected $2.3 billion 2009-10 deficit, Pennsylvania Gov. Edward G. Rendell (D) proposed a natural gas severance tax in his Feb. 4 budget address. "We have a Pennsylvania gold rush going on in the form of drilling for natural gas along what is known as the Marcellus shale. Scientists now estimate that if we can extract just 10% of the gas that exists below ground in the Marcellus, it would be enough to supply the natural gas needs of the entire United States for 2 years," he said. "Experts believe that much of the most potentially productive portions of the Marcellus Formation exist right here in Pennsylvania."

His plan calls for a 5% tax at the wellhead, plus 4.7¢/Mcf produced, identical to one that has been collected in neighboring West Virginia since 1987. State planners projected that it would produce nearly $1.82 billion over 5 years. Oil and gas associations in the Keystone State, however, warned that it potentially could destroy many current producers who have shallow, low-volume wells. The Pennsylvania Oil and Gas Association suggested, alternately, that the state could raise about the same amount with annual lease sales on state forest lands.

Other states' chief executives said they plan to continue existing energy expansion efforts. "Two years ago, I talked about the New Energy Economy as a way to build wind farms in wheat fields and make our universities research leaders in renewable energy," said Colorado Gov. Bill Ritter Jr. (D) on Jan. 4. "Today, our New Energy Economy is not just creating a culture of sustainability; it's fulfilling the promise of a

*Arkansas can help the US reduce its oil import dependence by continuing to develop alternative and renewable sources and conserve energy, said Gov. Mike D. Beebe (D) on Jan. 13. A severance tax on natural gas from the Arkansas portion of the Fayetteville shale play will supply significant revenue in the meantime, he added.*

new energy future and a new economic future for all of America."

Ritter said he was working with the state's congressional delegation and with US President Barack H. Obama's administration to ensure that the federal recovery package includes funds for electricity transmission lines. Within Colorado, Ritter continued, legislators have proposed bills that would require that all new single-family homes come with a "solar-ready" option, would help finance business and residential clean energy projects, and would develop a plan for wind and solar projects for rural schools.

## A role for gas

"My thanks also to Colorado's traditional energy sector, which is a key part of our New Energy Economy," Ritter said. "We have some of the richest natural gas reserves in the nation. We must ensure Colorado's gas continues to meet America's energy needs today and serves as a clean-burning bridge fuel for tomorrow. That's why I'm working with industry and others to include funds for gas pipelines in the federal recovery package," he said.

Ritter also said he would ask the legislature to finalize regulations, which the state's oil and gas commission passed in 2008, to improve oil and gas production practices. The Colorado Oil and Gas Association and other groups have said that the regulations are too restrictive and could halt production growth. The governor defended them. "I'm proud of the commission's work. They listened to every interested party and found the right balance. With these rules, Colorado companies and Colorado workers can successfully drill for gas, while our air, land, water, wildlife, and communities are protected," he declared.

North Dakota, meanwhile, began to invest in the future of its oil patch years ago by providing tax incentives to attract new investment and encourage exploration; by establishing a research fund to promote directional drilling and other new technologies that are



# A stripper well owner speaks up

The US oil and gas industry found plenty to dislike when President Barack Obama's administration announced its proposed federal budget. But it's possible that the subset that would be hurt quickest and hardest is its marginal, or "stripper," oil producers.

Their 420,000 low-volume wells each produce fewer than 15 b/d. Yet collectively stripper well producers represent 20%, or 1.2 million boe/d, of total US production, roughly equal to daily US energy imports from Saudi Arabia, according to the National Stripper Well Association.

"Without revision, these provisions would result in well abandonment and reduced oil and natural gas production, serving only to further harm America's fragile economy," said Dewey Bartlett Jr., NSWA chairman and president of Keener Oil Co., Tulsa.

## An Illinois producer

The owners and operators of these wells essentially are small business owners who are dramatically different from major oil companies, Bartlett noted.

Arlene P. Snyder, president and chief executive of Parish Oil Production Inc., Northbrook, Ill., is one of them. She recognizes that the country is in economic trouble, says that US President Barack H. Obama is working hard to clean up the mess, and thinks that everyone should help. Snyder would also like to stay in business.

"We are not large, integrated international oil companies reporting huge profits earned last quarter. Our only source of income is at the wellhead after paying the monthly operating expenses to get that oil out of the ground and into a tank," she said. Many stripper wells take 3 months to fill a stock tank before the oil can be sold to a refinery, she added.

Refiners set the price, Snyder said, and after several years of mergers and acquisitions, there are only two who buy Illinois basin stripper oil. "These refineries discount our sales price for our 40° sweet crude at $8.25/bbl below West Texas Intermediate pricing for sweet crude," she said.

## More sour crude

Most US refineries have retooled their operations to process imported sour crude, which also increasingly flows into the US Strategic Petroleum Reserve, Snyder said. Sweet crude costs less to process, "but refineries need volume every day and use sour crude because sweet crude production levels have dropped since 1986," she said.

Snyder said her small business might be able to absorb a reduced tax incentive. "But we cannot sustain the complete loss of the depletion allowance and the ability to write off intangible drilling costs in the year they are incurred," she said.

"We are in a very high-risk business. Even reworking existing wells costs a lot of money with no assurance we can even get it back. We must have a way to offset these huge gambles because we are a small company with limited operating capital," Snyder said.

Snyder hopes that Congress will recognize there are differences between her company and the likes of ExxonMobil Corp. ✦

*While he emphasized alternative and renewable sources, Colorado Gov. Bill Ritter Jr. (D) told legislators on Jan. 4 that traditional energy producers will be important as the state's economy recovers. He also asked lawmakers to finalize new oil and gas regulations which industry associations in Colorado say are too restrictive.*

applied in the Bakken Formation; by creating a pipeline authority to make sure refined products get to market; and that gas, which previously was flared at the wellhead, reaches consumers, Gov. John Hoeven (D) said on Jan. 6.

"To recruit and train workers, we established a Center of Excellence for Petroleum Safety and Technology at Williston State College to build the workforce," he added. Basin Electric Power Cooperative is working with an environmental technology company on a project to capture carbon dioxide from the power co-op's plant at Beulah and pipe it to North Dakota's oil patch for enhanced recovery, Hoeven said.

"All of these efforts, and more, have helped to drive the growth and development of our petroleum industry in North Dakota. And it doesn't stop there. Whether it's coal, wind, or renewable fuels like ethanol and biodiesel, we are continuing to pursue aggressive economic development," Hoeven said.

## Stabilize supplies

South Dakota Gov. M. Michael Rounds (R) said his state's government, businesses, and residents can contribute to economic growth by using energy more efficiently. "But, in addition to all of that, on the larger scale, our state and our nation need to stabilize and hopefully decrease the price of gasoline and other transportation fuels," he told legislators on Jan. 8. "We also need to stabilize supplies of those transportation fuels for our farmers, ranchers, businesses, ourselves, and for the tourists who want to visit our state. That means becoming much more energy independent from the Middle East and Venezuelan oil supplies."

Rounds said that, while South Dakotans are working hard to generate more energy from renewable sources, "huge supplies of renewable fuels for South Dakota and nationwide use will not happen overnight, nor will they be able to totally replace petroleum. Therefore, for our own security, stable prices, and adequate supply, the United States must start using more Canadian crude oil."

TransCanada Pipelines Ltd. has proposed a pipeline system from Alberta through the Dakotas to Oklahoma and Illinois which would transport 590,000 b/d of crude oil from tar sands to US refineries, he noted.

Rounds said he began issuing executive orders to let fuel delivery drivers operate beyond their normal legal hours so gasoline and diesel fuel could reach customers in eastern South Dakota. "Even with these efforts, last fall during our harvest, there was a time when most of the fuel pipelines supplying South Dakota and North Dakota were dry. Only one out of seven fuel terminals in South Dakota had fuel, and numerous gas stations were completely out of gasoline and diesel for more than 12 hr," he said.

"Ladies and gentlemen, this shortage was not caused by a natural disaster or cold weather. It was caused by a nationwide lack of refining capacity. And, it doesn't help us that we are at the end of most fuel distribution systems. We are going to have more and more supply shortages until we increase our refining capacity," Rounds told his state's lawmakers. Fortunately, South Dakota is a finalist for the Hyperion Energy Center, a complex that would include the first newly constructed US refinery since 1976, he added.

"The company is committed to this being the most technologically and environmentally advanced oil refinery in the world, and we will hold them to their promise," Rounds said. "In South Dakota, we roll out the red carpet, not the red tape, to any new potential business, but we do not cut corners. I believe this new refinery would help stabilize gasoline supplies in the Midwest, and that will be great for our farmers, our businesses, and all of us."

## Alaska's gas pipeline

Economic priorities should be a powerful incentive for Alaskans to think clearly and act decisively, not politically, in pursuing funding for the state's next major economic lifeline: the gas pipeline from the North Slope to markets in the Lower 48 states, according to Palin. Alaskans were told 30 years ago that it would be impossible to build the Trans Alaska Pipeline System, she pointed out.

The massive new project involves challenges too, she continued, "but we can be confident in this enterprise because it's founded on the fundamental interests of our state and nation. America needs energy [that is] affordable, abundant and secure. With international conflicts, war, and environmental concerns, laws and markets seek safe, clean energy, and that's what we offer. The last president supported a gas line, and so does the new president."

Without revenues from gas development, Alaska won't be able to fund its

priorities, and financial reserves will be depleted within a decade, she warned. "Working together, we're developing a 10-year plan to keep a healthy balance in the Constitutional Budget Reserve. We're laying up stores, until strong revenue comes in with the flow of natural gas to feed hungry markets here and outside," she said.

"In Alaska, all roads lead...to the North Slope and to the central importance of our North American gas line. America's security, Alaska's revenue, Alaskan careers, affordable fuel, even our ability to finally diversify our economy—all these hinge on the success of this great undertaking. I assure you: The line will be built. Gas will flow. Alaska will succeed," Palin declared.

Ironically, while the state has the largest US oil and gas supplies and is working to build a pipeline to deliver 4.5 bcfd of gas to markets farther south, Alaska's governor said that its citizens are more vulnerable than other Americans to fluctuating energy prices.

"The solution for our state is much the same as for the rest of our nation, only the source is ours and much closer to us, so delivery can come sooner," she said. "We're facilitating a smaller, in-state gas line with legislation we'll hand you next month. My goal for this in-state line is completion in 5 years. It will carry 460 MMcfd of gas to energize Alaska."

"Previously, we've relied on a diminishing gas supply from Cook Inlet, expensive diesel fuel, a mix of government subsidies, and not enough conservation, but that is not sustainable," Palin said. "And it shouldn't take another spike in energy costs to stir us into action. Alaska will help achieve energy independence and security for our country, and we can lead with a long-needed energy plan for America.

"But let us begin with energy security for ourselves," she added. "This includes meeting my goal of generating 50% of our electric power with renewable sources. That's an unprecedented policy across the US, but we're the state that can do it with our abundant renewables, and with Alaskan ingenuity." ✦

## WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

# Venezuela facing hard truth

If there's anything like an essential characteristic needed for the oil and gas industry, it's a sense of humor. In fact, when things get beyond anyone's control, the ability to laugh may be the best remedy.

That's how things are shaping up when it comes to Venezuela these days.

In fact, Venezuelan President Hugo Chavez has vowed that his brand of 21st century socialism would triumph—even if the price of oil plummeted to zero. But now, even El Presidente is facing a hard truth.

"Oil prices are very low," he acknowledged in a speech at a recent military parade in Caracas. "For Venezuela, this is tough and difficult. But even so, I will stick to what I have said: We are not going to cut spending on the missions...food, health, education and housing."

How will that happen? Enter Venezuela's oil minister Rafael Ramirez, who also serves as head of the state-owned Petroleos de Venezuela SA, to announce that the firm will cut spending to help the country.

## Ramirez the cost-cutter

Saying there had been "excessive spending" in recent years, when oil prices were high, Ramirez said, "We [PDVSA] have to adjust to a situation that does not allow for waste, spending that is not a priority."

"It's clear that we can't have the same level of spending as last year," said Ramirez, whose spending cuts come down to renegotiating deals with 250 contractors that were reached last year as prices climbed to record high levels.

Such cuts will enable PDVSA to drop production costs by 40%, Ramirez said.

Meanwhile, debt payments to some 91% of the company's 5,726 contractors began on Mar. 2. But don't get your hopes up. According to Ramirez, not everyone will be treated alike as "there is a segment with which we must sit down to discuss" new terms.

"I must defend the interests of the nation," he said, arguing that he could not pay, for example, for drilling services at last year's going rate.

## The Emperor's new cushion

Despite the need to tighten spending, Ramirez claims PDVSA has a financial "cushion" and can still maintain its planned investments of $125 billion for 2009-13.

The cushion of resources is so solid that "we can withstand and keep ourselves going in any situation." And echoing the president he serves so assiduously, Ramirez said, "We can work (even with) zero oil income."

Despite that cushion, though, Ramirez has been touting investment in Venezuela, saying that production costs in the Orinoco heavy crude belt are $1.50/bbl, making investment attractive despite the collapse in world oil prices.

"It's a huge opportunity right now, especially when they are canceling projects in Canada's heavy tar sands because of the higher costs," the minister said. "We're currently offering six blocks in the Orinoco, and we will remain open to foreign investment," Ramirez said.

Are you laughing yet? ✦

# Emphasis on urban areas affects drilling in Ohio

**Michael McCormac**
*Ohio Division of Natural Resources*
*Columbus*

Effective Sept. 16, 2004, a law went into effect that gives the Division of Mineral Resources Management sole authority in Ohio to regulate the permitting, locating, drilling, and operating of oil and gas wells and production facilities.

The law was adopted with the understanding that the regulation of oil and gas activities is a matter of general statewide interest that requires uniform statewide regulation. Previously, different standards were in effect throughout the state.

The law created a designation of urban areas and defined them as all municipalities and unincorporated civil townships with a population greater than 5,000. Urban areas are subject to greater rules and conditions than nonurban areas.

Allowing drilling in urban areas has affected both drilling and production. Since the law went into effect, about 23% of all wells drilled have been in areas defined as urban. In 2008, 318 of the 1,428 drilling permits issued were in urban areas (Table 1). The rise in proportion of drilling in urban areas has contributed to a turnaround in an otherwise downward trend in production in Ohio.

## Permitting and drilling

The number of permits issued in 2008 was 8% more than in 2007.

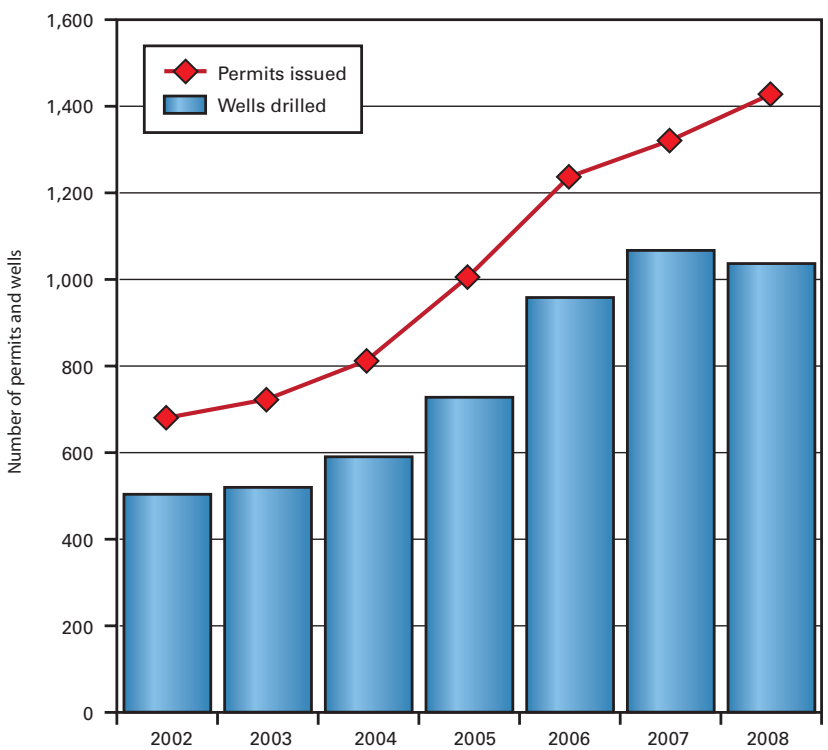
The majority of these permits targeted the Clinton sandstone (72%), followed by the Devonian shale (12%) and then permits below the Cambro-Ordovician Knox unconformity (11%).

Sixteen permits were issued to the Marcellus shale formation. Permits were issued in an average of 13 days of being filed.

For the second consecutive year and only the third time since 1991, more than 1,000 wells were drilled. An estimated 1,049 oil and gas wells were drilled in 2008, a decrease of 16 wells or 1.5% from 2007. This is the first decrease since 2002 (Fig. 1). Wells

OHIO PERMITS AND DRILLING

Fig. 1



were drilled in 44 of Ohio's 88 counties, six fewer counties than in 2007.

## Well completions

At the time of this writing in late February, Ohio oil and gas owners had submitted 811 well completion reports, representing 77% of the wells drilled in 2008.

These reports showed that 756 wells were productive and 55 were dry holes, for a 93.2% completion rate. Total depths ranged from 420 ft in the Big Injun sandstone in Perry County to 8,897 ft in Precambrian granite in Guernsey County.

An estimated 4,057,429 ft of hole were drilled, a decrease of 104,273 ft from 2007. Well depth averaged 3,868 ft, a decrease of 40 ft/well.

## Targeted formations

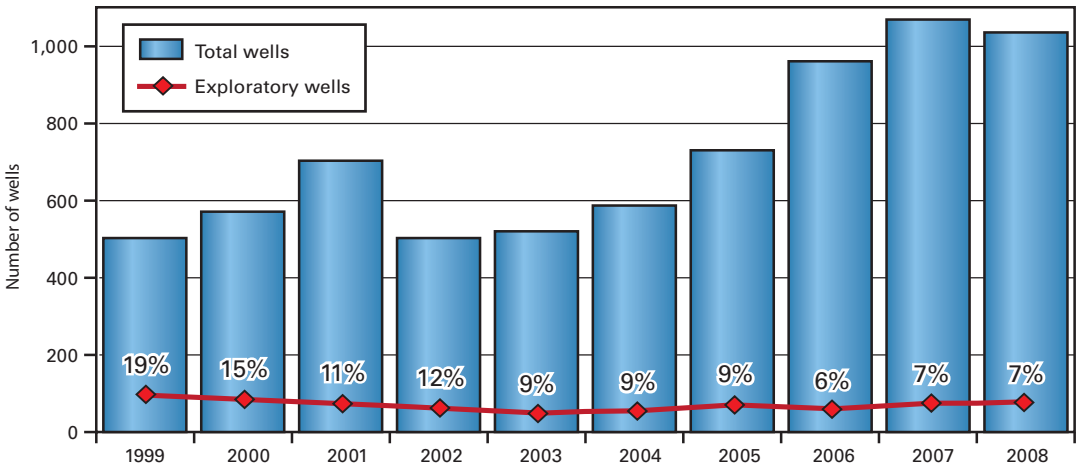
Completion zones ranged from a Pennsylvanian coal (for coalbed methane) to Precambrian basement.

The Clinton sandstone was the most actively drilled zone accounting for 61% of all wells drilled. An estimated 638 wells were drilled, 30 fewer than in 2007. Clinton sandstone wells averaged 4,089 ft in depth and were drilled in 25 counties. The most active counties were Cuyahoga 67 wells, Geauga 66, and Licking 53.

An estimated 151 wells were drilled to the Ohio shale, a decrease of 6 wells. Sixteen of these wells were horizontally drilled. It is too early to know whether this technology has been effective. Ohio shale drilling occurred in 11 counties. Monroe led with 74 wells followed by Noble with 28.

### OHIO EXPLORATORY WELL RATIO

Fig. 2




### OHIO DRILLING PERMITS

Table 1

| Year | Urban areas | Total permits |
|---|---|---|
| 2005 | 240 | 1,011 |
| 2006 | 289 | 1,239 |
| 2007 | 311 | 1,322 |
| 2008 | 318 | 1,428 |

Drilling to the Knox formations totaled 102 wells, 2 fewer than in 2007. Of those, 33 were dry holes, resulting in a productive rate of 68%. The majority of these wells, 45, were drilled to the Beekmantown dolomite.

## Most active counties

Monroe County was ranked first for the fifth consecutive year with 75 wells drilled, and the majority of these wells were drilled to the Ohio shale.

Urbanized drilling accounted for almost every well in the next most active counties, Cuyahoga (69) and Geauga (67) (Table 2).

### 10 MOST ACTIVE OHIO COUNTIES, 2008

Table 2

| 2008 rank | County | Wells drilled | 2007 rank | Avg. depth per well, ft | Footage drilled |
|---|---|---|---|---|---|
| 1 | Monroe | 75 | 1 | 2,833 | 212,475 |
| 2 | Cuyahoga | 69 | 3 | 3,647 | 251,643 |
| 3 | Geauga | 67 | 2 | 4,179 | 279,993 |
| 4 | Knox | 62 | 9 | 2,628 | 162,936 |
| 5 | Licking | 58 | 7 | 2,454 | 142,332 |
| 6 | Tuscarawas | 54 | 4 | 6,166 | 332,964 |
| 7 | Trumbull | 52 | 4 | 5,061 | 263,172 |
| 8 | Stark | 44 | 6 | 5,050 | 222,200 |
| 9 | Muskingum | 44 | 20 | 4,171 | 183,525 |
| 10 | Noble | 40 | 20 | 4,168 | 166,720 |

## Directional drilling

This technology is generally being used to access oil and gas in the following ways: under environmentally sensitive areas or densely populated areas and horizontally in the Devonian shale.

In 2008, 71 directional drilling permits were issued to drill directional wells in 13 counties. This included 26 permits to horizontally drill in the Devonian shale, and many of these were radials from the same vertical boreholes. These were located in Gallia (19) and Jackson (7) counties. The majority of the rest of the permits were issued to the Clinton sandstone in northeastern Ohio. The most active counties were Summit (11) and Cuyahoga (8).

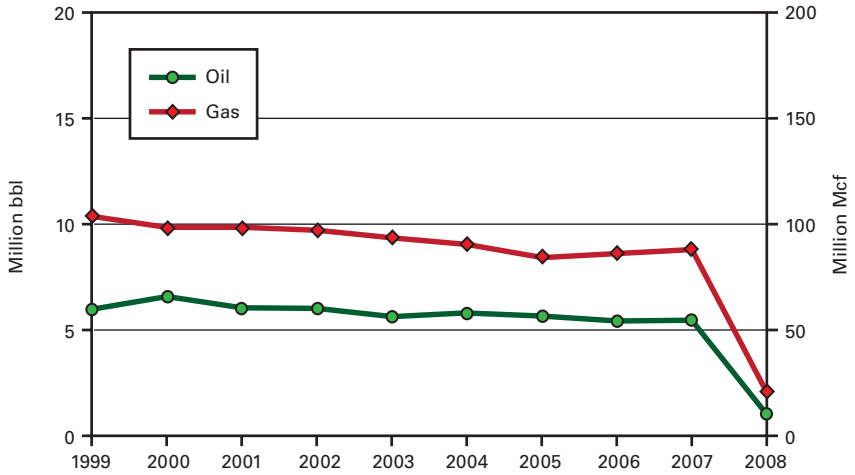
## Exploratory wells

Wells in Ohio are classified as "development wells" or "exploratory wells" based on American Association of Petroleum Geologists guidelines.

A well completed in a known oil and gas bearing formation within 1 mile of any well completed in the same formation is classified as a "development well." A well is classified as "exploratory" if it is completed in a formation not usually known to be oil and gas bearing or is located more than 1 mile from the nearest well com-

## OHIO OIL AND GAS PRODUCTION

Fig. 3




## OHIO WELLHEAD PRICES*

Table 3

| Year | Oil, $/bbl | Gas, $/Mcf |
|---|---|---|
| 1999 | 16.20 | 2.41 |
| 2000 | 26.76 | 4.06 |
| 2001 | 21.84 | 4.49 |
| 2002 | 22.50 | 3.56 |
| 2003 | 27.64 | 5.90 |
| 2004 | 38.00 | 6.65 |
| 2005 | 53.03 | 9.03 |
| 2006 | 62.43 | 7.75 |
| 2007 | 67.69 | 7.40 |
| 2008 | 93.79 | 9.77 |

*Year's average.

pleted in the same oil and gas bearing formation.

Exploratory drilling continues to decline as a percentage of the total number of wells drilled (Fig. 2). Seventy-five wells (7%) of all wells completed were classified as exploratory, which is comparable to 2007. Of these, 51 were productive and 24 were dry, representing a 68% success rate.

Exploratory wells were drilled in 28 counties. Gallia and Guernsey counties each had nine exploratory wells.

Wells drilled to the Devonian shale (25) and below the Knox unconformity (26) accounted for the majority of exploratory activity. Drilling to the Devonian shale continues to expand geographically each year as new areas are explored. All of these wells were reported as productive. A hurdle in some of these areas is the lack of pipeline access.

Wells drilled to formations below the Knox unconformity, such as the Beekmantown dolomite, Rose Run sandstone, and Trempealeau dolomite are almost always seismic prospects. Half of these wells were dry holes.

### Production overview

Ohio's total reported crude oil production was 5,554,235 bbl, an increase of 1.83% from 2007 (Fig. 3).

In 2008, production averaged 15,217 b/d compared with 14,944 b/d in 2007. Through 2008, Ohio wells have produced 1,126,734,443 bbl.

Ohio wells produced 84,858,015 Mcf of natural gas in 2008, a decrease of 3.67% from 2007 (Fig. 3). Gas production figures include an estimated 840,178 Mcf of gas used on leases.

In 2008, production averaged 232,488 Mcfd compared with 241,355 Mcfd in 2007. Through 2008, Ohio wells have produced a cumulative 8,353,152,305 Mcf of gas.

Crude oil production valued at $520,949,200, increased 41.1% from its 2007 value. The average price per barrel was a record $93.79, a 38.6% increase from 2007's average (Table 3).

Posted oil prices ranged from a high of $138/bbl on July 4 to a low of $28.25/bbl on Dec. 10.

The market value of natural gas increased 27.2% to $829,126,591. The price paid in 2008 averaged $9.77/Mcf, an increase of $2.37/Mcf from 2007 (Table 3). The Appalachian price index, based on a weighted average between Columbia and Dominion, ranged from a high of $13.73 in July to a low of $6.83 in November.

Ohio's combined oil and gas market value increased by 32.2%. The total dollar value of $1,350,075,791 is the highest on record. It exceeded the $1 billion mark for the fourth straight year and only the fifth time ever, the first time having been in 1984. ✦

**The author**

*Mike McCormac (mike.mccormac@dnr.state.oh.us) is a geologist and manager of the oil and gas permitting section with the Ohio Division of Mineral Resources Management. He also administrates the orphan well program. He has authored the division's summary of Ohio oil and gas activities since 1985 and has been employed with Ohio Department of Natural Resources since 1980. He has a BA in geology from Capital University.*

## Hungary

Hungarian Horizon Energy Ltd., a subsidiary of Aspect Energy LLC, Denver, plans fast-track development of the mid-2008 Hajdunanas discovery in the Pannonian basin in northeastern Hungary.

First commercial gas production is expected by mid-2009, 50% participant JKX Oil & Gas PLC said in January. JKX estimated a preliminary 12 bcf of gas in place in Pannonian sands.

The Hajdunanas-2 appraisal well went to TD 1,467 m and cut several Miocene Pannonian gas bearing intervals at 990-1,080 m. The productive Miocene volcaniclastic sequence found in the discovery well was tight, and a deeper Miocene target was not pursued.

# PETROLEUM EVENTS CALENDAR 2009

**Subsea Tieback Forum & Exhibition**
March 3 – 5, 2009
San Antonio, Texas USA
Website: www.subseatiebackforum.com

**Offshore Asia Conference & Exhibition**
March 31 – April 2, 2009
Bangkok, Thailand
Website: www.offshoreasiaevent.com

**Oil Sands and Heavy Oil Technologies Conference & Exhibition**
July 14 – 16, 2009
Calgary, Alberta, Canada
Website: www.oilsandstechnologies.com

**Oil & Gas Maintenance Technology North America Conference & Exhibition**
September 1 – 3, 2009
New Orleans, Louisiana USA
Website: www.ogmtna.com

**Unconventional Gas International Conference & Exhibition**
September 29 – October 1, 2009
Ft. Worth, Texas USA
Website: www.unconventionalgas.net

**Deepwater Operations Conference & Exhibition**
November 10 – 12, 2009
Galveston, Texas USA
Website: www.deepwateroperations.com

**Offshore Middle East Conference & Exhibition**
October 27 – 29, 2009
Manama, Kingdom of Bahrain
Website: www.offshoremiddleeast.com

**Deep Offshore Technology**
International Conference and Exhibition
November 3 - 5, 2009
Monte Carlo, Monaco
Website: www.deepoffshoretechnology.com

**Emerging Unconventional Resources Conference & Exhibition**
December 8 – 10, 2009
Shreveport, Louisiana USA
Website: www.EmergingResourcesConference.com

**Oil & Gas Maintenance Technology Conference & Exhibition**
Co-located Pipeline Rehabilitation and Maintenance
January 19 – 21, 2010
Cairo, Egypt
Website: www.oilandgasmaintenance.com

**Pipeline Rehabilitation & Maintenance**
Co-located with Oil & Gas Maintenance Technology
January 19 – 21, 2010
Cairo, Egypt
Website: www.pipeline-rehab.com

**Deep Offshore Technology**
International Conference and Exhibition
February 2 – 4, 2010
Houston, Texas, USA
Website: www.dotinternational.net

**Offshore West Africa Conference & Exhibition**
March 23 – 25, 2010
Luanda, Angola
Website: www.offshorewestafrica.com

**Rocky Mountain Unconventional Resources Conference & Exhibition**
April 6 – 8, 2010
Denver, Colorado USA
Website: www.RMURconference.com

**WORLD ENERGY CONGRESS**
September 12 – 16, 2010
Montréal, Quebec, Canada
Website: www.wecmontreal2010exhibit.com

The appraisal well flowed 7.4 MMcfd of gas with 1,250 psi flowing wellhead pressure on a 14-mm choke from a 25-m upper zone and 8.5 MMcfd with 1,308 psi on a 16-mm choke from a 5-m lower zone.

Further drilling is needed to define the commercial significance of the underlying Hajdunanas Miocene volcaniclastic interval and the deeper Miocene formation, JKX said.

The discovery is on the Hernad I and II licenses that total 5,420 sq km.

## Iraq

Niko Resources Ltd., Calgary, began shooting seismic on the 846 sq km Qara Dagh block southeast of Sulaymaniya in Iraqi Kurdistan, said partner Vast Exploration Inc., Calgary.

The 4-5 month program is for a minimum of 350 line-km of 2D seismic using a combination of vibrator and dynamite sources. It could be extended to 390 line-km if more data are required.

## Netherlands

A group led by Cirrus Energy Corp., Calgary, said the L11-13 directional well in the Netherlands North Sea stabilized at 30.6 MMcfd of dry gas on a 48/64-in. choke with 2,900 psig flowing wellhead pressure.

The well was drilled from the L11b-A production platform into the unitized L8-D field, which potentially straddles blocks L8a, L8b, and L11b. Results are being integrated with existing data from L8-D field, where the 2004 L8-16x discovery well drillstem tested at rates up to 16.1 MMscfd from the same Permian Rotliegend Group sandstones.

Bottomhole locations of L11-13 and L8-16x are 5.9 km apart.

Unit interests are Cirrus 25.479%, EBN 41.9%, TAQA 15%, EWE AG 13.4%, DSM Energie BV 2.88%, and Energy06 Investments BV 1.341%.

## Poland

Polish Oil & Gas Co. and FX Energy Inc., Salt Lake City, reported a commercial discovery at the Kromolice-2 well in the Fences area in Poland.

Production tests are to start shortly. The well cut 114 ft of gross pay in Permian Rotliegend sandstone with porosity as high as 28% and averaging 15.1%.

The Sroda-4, Kromolice-1 and 2, and Winna Gora wells "provide the critical mass" for a central gathering system, FX Energy said.

Production facilities are under construction at the Roszkow well farther southeast in the Fences area.

## Somaliland

The ministry of water and mineral resources in Hargeisa launched Somaliland's first hydrocarbon bid round on Feb. 19, 2009.

On offer are eight land and offshore blocks totaling more than 89,624 sq km.

The ministry noted striking geological similarities between Yemen's Balhaf graben and Somaliland's Berbera basin. Other indicators of hydrocarbon potential are oil and gas seeps at Dagah Shabel, and most historical wells in the area contain multiple zones with shows.

In preparation for the round, TGS-NOPEC Geophysical Co. ASA shot 5,300 line-km of seismic, gravity, and magnetic data offshore and 34,700 line-km of high resolution aeromagnetic data over all known petroleum basins. This is the first new geophysical data acquired in almost 30 years.

Bids are due Aug. 15, and concessions are to be awarded on Dec. 15, 2009.

## Louisiana

EXCO Resources Inc., Dallas, completed its first Haynesville shale horizontal well in northwest Louisiana in December 2008.

The Oden 30H-6 in DeSoto Parish flowed at an initial rate of 22.9 MMcfd of gas and produced 1 bcf in its first 64 days on production. It was making more than 12 MMcfd in late February. EXCO's interest is 100%.

EXCO spud its second and third operated horizontal wells late in the year. It has completed one of the two, the Lattin 24-4 in DeSoto, made an initial 24.2 MMcfd with 7,350 psi flowing pressure on a 26/64-in. choke. EXCOs interest is 92.8%.

The third well is in completion and should be on line in early March 2009.

## Texas

**East**

Berry Petroleum Co., Denver, identified more than 100 drilling locations and 75 recompletion opportunities on East Texas properties it acquired in July 2008 for $668 million.

The drilling locations target stacked pay in various productive zones including Pettit, Travis Peak, Cotton Valley sands, Cotton Valley lime, Bossier sands, and Haynesville and Bossier shales on the 4,500 net acres in Limestone and Harrison counties.

The acquisition included a gathering system that is expected to take all current and future production from the properties.

Berry is drilling with one rig and plans to start horizontal drilling in the Haynesville shale in Harrison County in the third quarter of 2009

## Virginia

Initial production rates have averaged 1.1 MMcfd at seven horizontal wells completed to date from Upper Devonian Huron shale in Nora field in western Virginia, said Range Resources Corp., Fort Worth.

Range has drilled nine horizontal Huron wells to date, including four in the last quarter of 2008. Initial rate was 1.5 MMcfd at a horizontal well completed in Mississippian Berea sandstone.

The company's 2009 plan is to drill 220 coalbed methane wells, 60 tight sand gas wells, and 20 horizontal Huron shale wells in Nora field, in which Range's working interest is 50%.

# Real-time well optimization stabilizes, adds production

**Ron Cramer**
*Shell Global Solutions (US) Inc.*
*Houston*

**Keat-Choon Goh**
**Charlie Moncur**
*Shell Global Solutions Inc.*
*Rijswijk, Netherlands*

Several field cases show how Shell Group's use of software for monitoring and optimizing production has reduced decline rates.


Software data-driven well models allow prediction of changes to overall and individual well production because of changes to individual well set points such as production choke settings and lift-gas rates. The software then computes well set points for optimizing oil and gas production subject to various well and production constraints, thereby:

- Decreasing field decline, sustained during several years.
- Increasing production by reducing platform start-up time.
- Providing more stable well production.

## Production measurements

In conventional practice, operators measure individual well oil, gas, and water production weekly or monthly basis in shared well test facilities. The net effect is that well measurements represent only about 1% of the production and operators assume that the wells produce at the same rates for the remaining 99% of the time.

This assumption leads to many production management problems. Hence, management of oil and gas production from a cluster of wells is difficult and leads to late diagnosis of production problems and slow and conservative handling of production constraints.

A software application developed by Shell Global Solutions (FieldWare Production Universe) provides continuous real-time estimates of well-by-well oil, water, and gas production. The software bases its estimates on data-driven models constructed and updated from production well tests and real-time production data.

The software is cost effective and fast to deploy because it uses existing infrastructure.

This article addresses application of the software's data-driven techniques for well and process optimization. For optimization, the data-driven well models allow for the prediction of the changes to overall and individual well production because of changes to individual well production chokes, lift-gas rates, or other similar set points. The software then computes the set point for optimizing oil and gas production subject to various well and overall production constraints.

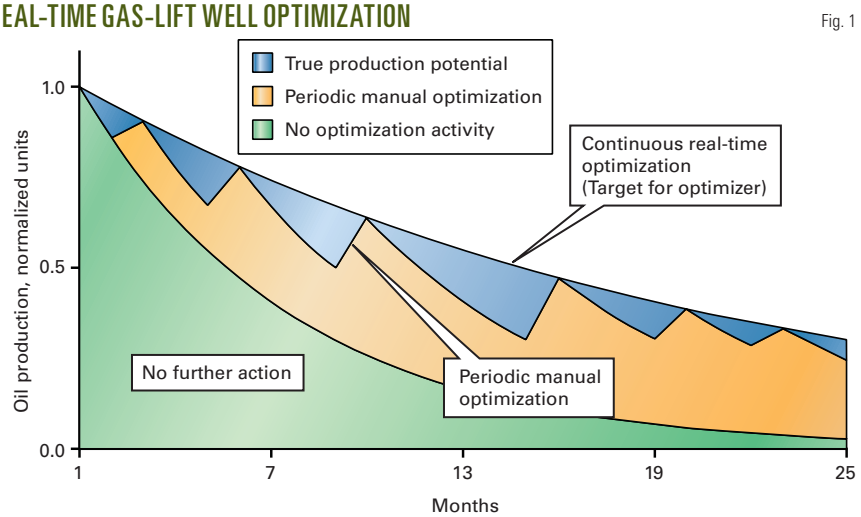
## Software background

The software is a data-driven modeling application developed by Shell. A previous article (OGJ, Mar. 5, 2007, p. 49) described the development background and early operational experience of the software within the Shell Group.

To improve on problems with periodic test separator measurements, operators have used several approaches

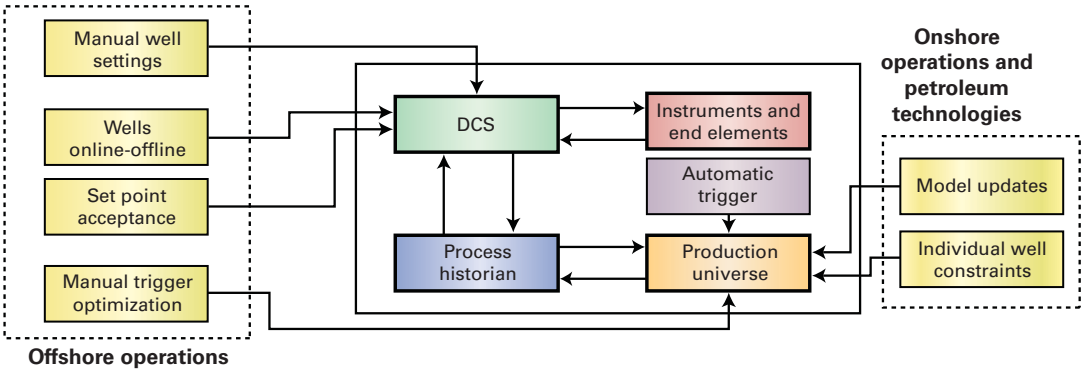
REAL-TIME GAS-LIFT WELL OPTIMIZATION

Fig. 1



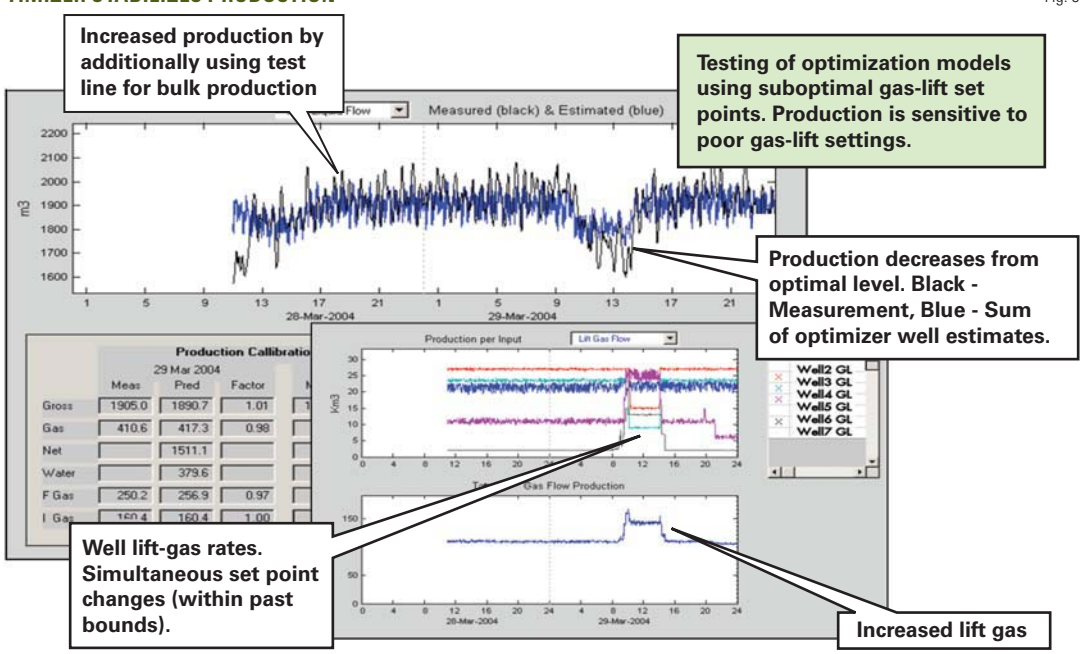
## DATA ACQUISITION AND CONTROL INFRASTRUCTURE

Fig. 2




## OPTIMIZER STABILIZES PRODUCTION

Fig. 3




combining a well's physical models with real-time wellhead pressures and temperatures to predict three-phase flow in real time or near real time.

In practice, operators found a well's physical models difficult to set up, calibrate, and maintain in an operating environment.

The data-driven software approach, in contrast, takes advantage of the well test and available production metering in conventional production operations, and addresses operational sustainability issues related to physical models for well production surveillance, particularly for changing well conditions and instrumentation uncertainty.

The software requires an input of an abbreviated multirate well test along with historic well test results for the modeling process that generates the data-driven well models. These models relate the three-phase flow from the well on test with signals from the wellhead instrumentation such as tubinghead pressures and temperatures, lift-gas injection rates, and production choke openings.

The software application has intuitive graphical user interfaces for operator data load and display and well model configuration and validation with minimal training. The software's underlying concepts are simple and have a clear relationship to the familiar well testing process.

Data from subsequent well tests automatically upload into software for model validation or updating. Algorithms within the software automatically indicate when a model requires updating.

Use of data-driven models for well production surveillance has several advantages, including simplicity of approach and how it incorporates and extends the conventional well testing process. The process requires no numerical assumptions about the underlying physics of the well.

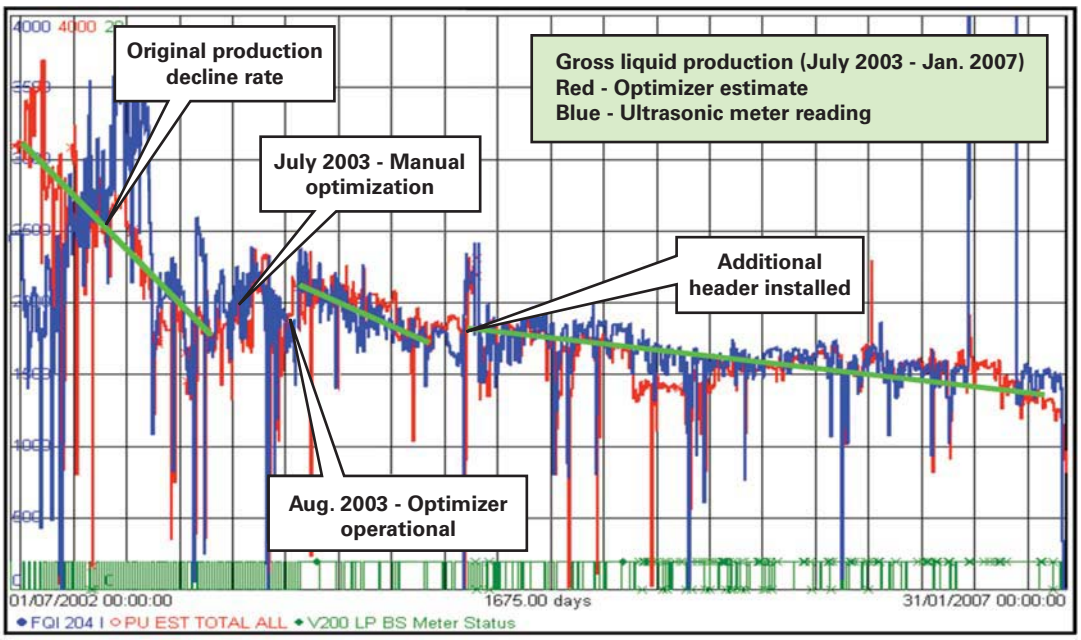
In addition, because operators often infrequently calibrate wellhead instrumentation, one benefit of this software is that it requires only repeatable well measurements within limits. Absolute measurement accuracy is not critical.

To ensure robustness, the software creates several independent models for each well with different inputs. This allows well estimates to continue even if an individual instrument fails.

The net effect is that the software's real-time well flow estimates, comparison with bulk measurements, fallback

PLATFORM PRODUCTION BEFORE AND AFTER OPTIMIZER

Fig. 4




models, and graphical user interface provide:

- Daily production and deferment totals for individual and collective wells.
- Real-time cross-check on the quality of the estimates, indicating need for retesting, and identifying instrumentation problems.
- Well flow estimates when the wells are not on test by streaming real-time well data to the models. The models also compare automatically the sum of the estimated well production with real time, single-phase flows as physically measured by export or bulk meters
- Daily allocation factors.
- Fast and cost effective implementation.

## Optimizer

Operators can also use the data-driven models for continuously estimating well flow to predict well production for given values of well production variables, such as choke position, lift-gas injection rates, and pump speed. The software optimizer uses data-driven models to optimize estimated oil production for a given well by computing the choke or lift-gas set points for maximum oil or gas production from that well alone, while considering constraints, such as:

- Gas-liquid or gas-oil ratio at a value required for good reservoir management.
- Lift-gas injection rate within prespecified limits.
- Production separator liquid handling capacity.
- Produced-water disposal capacity.
- Lift-gas compression capacity.
- Gas export demand or export compression capacity.
- Gas or oil export constraints due to pipeline issues or pump maintenance.
- Venting and flaring constraints.
- Minimum produced water requirements to support water injection for pressure maintenance.
- Injection voidage replacement limits.

Further, limited production system capacity can translate also into increased well production pressures, for example, due to restricted gas handling capability in the production separator. In such cases, high gas production from one well may result in a higher common header pressure, thereby backing out production from other wells.

The optimizer emulates these well interactions by generating data-driven header pressure vs. fluid production rate models and then combines and uses them with the previously discussed well models.

Daily production optimization determines suitable well set points to maximize production subject to applicable well and facility constraints. Common optimization problem formulations include:

- Maximizing net oil production with limited lift-gas availability, for example, lift-gas compression outage or failure.
- Maximizing net oil production while meeting gas export nominations.
- Maximizing condensate production while maintaining gas export nominations.
- Optimizing the short-term facility revenue, for example, if the facility exports both oil and gas and the software knows the relative incremental fiscal revenue values of the oil and gas streams.

With the discussed production targets and constraints, plus the models of the wells and the headers, the optimizer can then automatically compute optimal lift gas or production choke set points.

For gas-lifted wells, Fig. 1 illustrates the generation of daily set points and on-demand production to sustain total production at field capacity.

The software also may use the optimized set points to provide optimal response to changes in the produc-

tion system, for example, when gas demand drops, or when a lift-gas compressors trips.

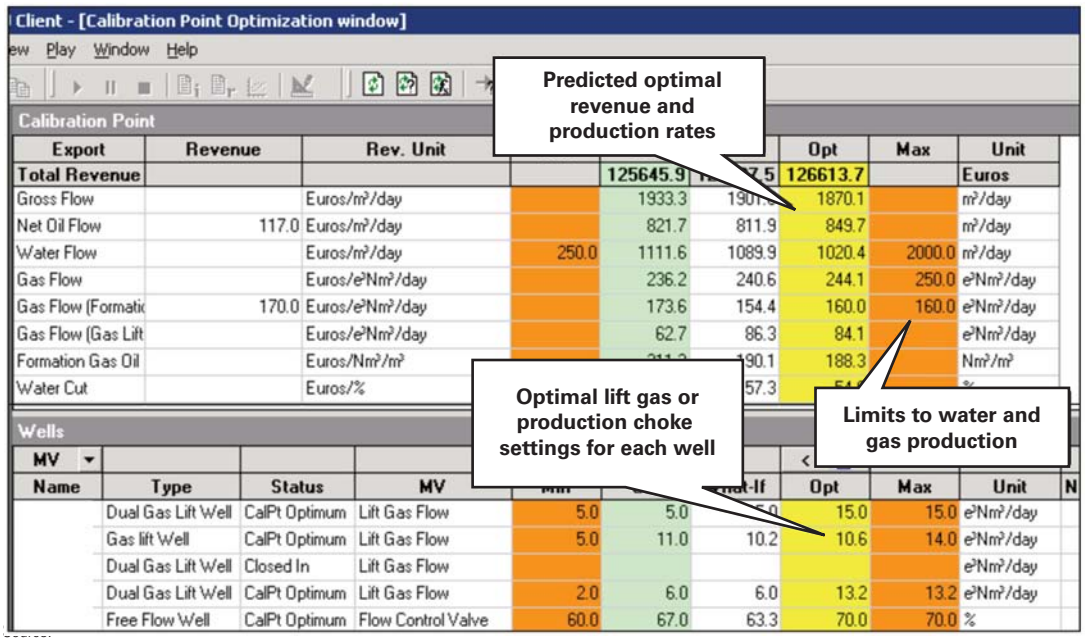
The software provides the operator with set points for manual entry into the control system, or passed to the control system, directly or through a middleware layer such as a process historian (Fig. 2).

Maintenance of the optimization models requires multirate well testing for well flow estimation.

When a production upset occurs, the optimizer, when set, can detect the resulting change in the system constraints, and compute optimal well set points. If the operator shuts in temporarily the well, such as for wireline activities, the optimizer can compute new optimal set points for the remaining wells.

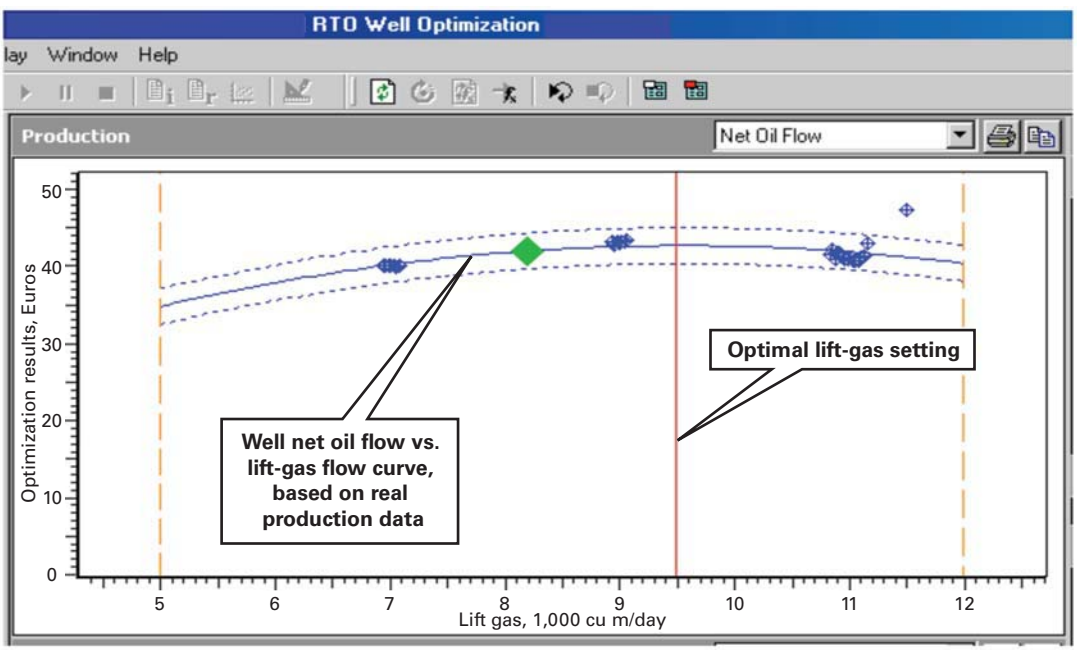
## Optimizer's user interface

Fig. 5




## Optimizer curves

Fig. 6




## Case studies

Several Shell production facilities have deployed the optimizer. In one case, the optimizer is on an offshore production platform with 15 gas-lifted wells.

On this platform, all wells have tubinghead transmitters, and six of the largest producers have downhole pressure gauges. The wells also have closed-loop flow controllers on their lift-gas injection lines.

Data transmitted from the platform go to other platforms and ashore. This allows operators to monitor the production data in real time and to change the set points for the lift-gas flow rates individually and remotely from the onshore control room.

After setting up and applying the initial well models, the operators observed elevated production header pressures, indicating much interaction between the wells. Hence, they used the

optimizer to model the well sensitivity to changes in header pressure. The optimizer computed optimal well lift-gas set points to maximize gross production, taking into account header interaction, backpressure effects of gas production, and lift-gas injection rate constraints.

To verify the benefits of the optimizer, the operators conducted a sensitivity analysis on the lift-gas rate. Fig. 3 illustrates a case in which the analyst simultaneously changed the lift-gas injection rates to suboptimal settings, resulting in production decline in spite of an increase in lift-gas injection. This validated the value of the optimizer.

The optimizer modeling and quantification of gas-lift header pressure effects indicated the need for an additional flowline to minimize backpressure effects. When installed, the additional header helped reduce backpressure that led to a corresponding production increase.

The optimizer application decreased production decline. Fig. 4 shows the 5-year trend of platform production before and after optimization. The trend confirms that the use of the optimizer has led to more stable operations and has reduced production decline.

Shell also has deployed the optimizer in onshore fields. One such production facility is in a heavily populated urban area with one gas well, five free flowing oil wells and nine gas-lifted wells. The oil goes to a nearby refinery and gas enters a local gas grid.

The location does not allow venting, flaring, and surface water disposal; hence, these limitations constrain production. Other constraints that limit total gas production are export and lift-gas compressors availability and the gas offtake rate.

The field also has to produce a minimum amount of injected water for reservoir pressure maintenance. The constraint on water production, however, is from a combination of water injection and water disposal capacity.

Gas sales detract from lift-gas required for oil and water production. Due to the direct supply of gas to the gas grid, the gas offtake can change on minimal notice.

Shell constructed optimizer models for all of the wells and incorporated the overall production constraints such as export gas limits, compression capacity, and water handling capacity (Fig. 5).

Because the field exported both oil and gas, Shell configured the optimizer to optimize on incremental revenue from oil and gas sales.

Since introduction of the optimizer on the production station, the daily production stabilized. Fig. 6 shows the optimal set points derived.

A third case illustrates another application in an offshore oil production facility.

This offshore platform produces 6,000 cu m/day of oil and 450,000 cu m/day of gas from 33 platform wells and two subsea tiebacks. The platform for power uses about 60% of the gas production. All wells are on gas-lift and have water cuts ranging between 10 and 95% with an overall 78 cu m/cu m GOR.

Lift-gas optimization on the platform was a process that had evolved over time. The process involved a large number of users and data flows. Users only were aware of their part of the process and different shifts used different optimization processes.

The new optimizer provides a more consistent and transparent process. Onshore-based petroleum engineers determine the models and rules for the optimization and a production server solely holds all data relevant to optimization for consistent use by all users. The users obtain all optimization data from the process historian and the distributed control system (DCS) receives all optimal gas lift set points via the historian (Fig. 2).

A key business driver for implementing the optimizer was the rate at which the operator can restart a platform after a trip shutdown. Since the implementation of optimizer in November 2006, the platform has experience several trips. The optimizer has enabled platform start-up on average 25% faster than before with a corresponding increase in production. ✦

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# Newbuild cantilevered jack up headed for work off India

Even as the world's drilling activity trends downward, new offshore rigs continue to enter the market. One of the latest entrants is the Deep Driller 8 jack up (photo).

The rig is the last in a series of five KFELS Super B Class cantilevered jack up drilling units built by Keppel FELS Ltd. for Aban Singapore Pte. Ltd. since 2006.



*Keppel FELS recently completed construction of the Deep Driller 8 cantilevered jack up in Singapore. Photo from Keppel FELS.*

Keppel FELS says the Super B Class design is one of the world's deepest drilling rigs, with capabilities for drilling high pressure, high-temperature wells up to 35,000 ft in 350 ft of water.

Hull dimensions are 246-ft length, 218-ft width, and 25-ft depth. The legs have a 486-ft length, and the rig's air gap is 50 ft.

Other design parameters include a 1,000-ton hook load, 1,000-ton rotary capacity, 5,586-ton variable load, and 1,350-ton maximum combined cantilever load.

The drawworks on the rig is a National Oilwell Varco Model SSDG-4600-57, with 4 x 1,150-hp ac electric motors and regenerative braking. The rig has a National Oilwell Varco Model HPS-1000-2E-AC-KT, 2-million lb capacity top drive and three National Oilwell Varco Model 14-P-220 triplex mud pumps.

According to Jefferies & Co. Inc.'s November 2008 Offshore Drilling Monthly, the rig's estimated cost was $140 million, and the rig has a 5-month, $200,000/day contract with Hidustan Oil Exploration Co. Ltd. for work off India.

Keppel FELS is a unit of Keppel Corp. Ltd. and specializes in offshore rigs, ship repair and conversion, and specialized shipbuilding.

Aban Singapore Pte. Ltd. is a unit of Aban Offshore Ltd., which is India's largest drilling contractor in the private sector. ✦

# Compositional variety complicates processing plans for US shale gas

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Recently higher gas prices and improved drilling technology have spurred shale gas drilling across the US. Fig. 1 shows the shale plays currently being explored.

Some of the more popular areas are the Barnett, Haynesville, and Fayetteville shales in the South and the Marcellus, New Albany, and Antrim shales in the East and Midwest. These plays represent a large portion of current and future gas production.

But all shale gas is not the same, and gas processing requirements for shale gas can vary from area to area. As a result, shale gas processors must be concerned about elevated ethane and nitrogen levels across a field. Other concerns are the increased requirements of urban gas processing. In addition, the rapid production growth in emerging shale areas can be difficult to handle.

This article reviews which gas processing technologies are appropriate for the variety of US shale gas qualities being produced and planned to be produced and reviews regional gas processing capacities to handle current and future production of shale gas.

*Based on a presentation to the Annual Forum, Gas Processors Association—Houston Chapter, Oct. 7, 2008, Houston.*

## Gas processing

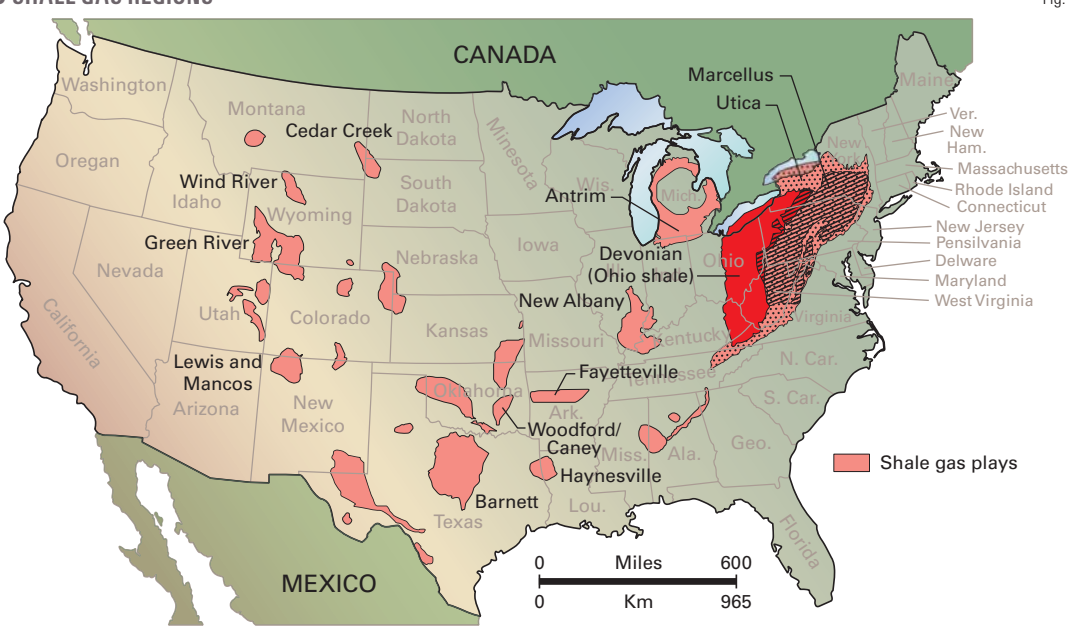
Gas processing removes one or more components from produced gas to prepare it for use. Common components removed to meet pipeline, safety, environmental, and quality specifications include $H_2S$, $CO_2$, $N_2$, heavy hydrocarbons, and water. The technique employed to process the gas varies with the components to be removed as well as with the properties of the gas stream (e.g., temperature, pressure, composition, flow rate).

Acid-gas removal is commonly by absorption of the $H_2S$ and $CO_2$ into aqueous amine solutions. This technique works well for high-pressure gas streams and those with moderate to high concentrations of the acid-gas component.

Physical solvents such as methanol or the polymer DEGP, or Selexol may also be used in some cases. And, if the $CO_2$ level is very high, such as in gas from $CO_2$-flooded reservoirs, membrane technology affords bulk $CO_2$ removal in advance of processing with another method. For minimal amounts

US SHALE GAS REGIONS

Fig. 1




Source: Energy Information Administration

of $H_2S$ in a gas stream, scavengers can be a cost-effective approach to $H_2S$ removal.

Natural gas that becomes saturated with water in the reservoir requires dehydration to increase the heating value of the gas and to prevent pipeline corrosion and formation of solid hydrates.

In most cases, dehydration with a glycol is employed. The water-rich glycol can be regenerated by reducing pressure and applying heat. Another possible dehydration method is use of molecular sieves that contact the gas with a solid adsorbent to remove the water. Molecular sieves can remove the water down to the extremely low levels required for cryogenic separation processes.

Distillation uses the different boiling points of heavier hydrocarbons and nitrogen for separation. Cryogenic temperatures, required for separation of nitrogen and methane, are achieved by refrigeration and expansion of the gas through an expander. Removal of the heavy hydrocarbons is dictated by pipeline quality requirements, while deep removal is based on the economics of NGL production.

## Processing requirements

The following reviews six shale gas plays, their compositions, and processing needs: Barnett, Marcellus, Fayetteville, New Albany, Antrim, and Haynesville.

### Barnett

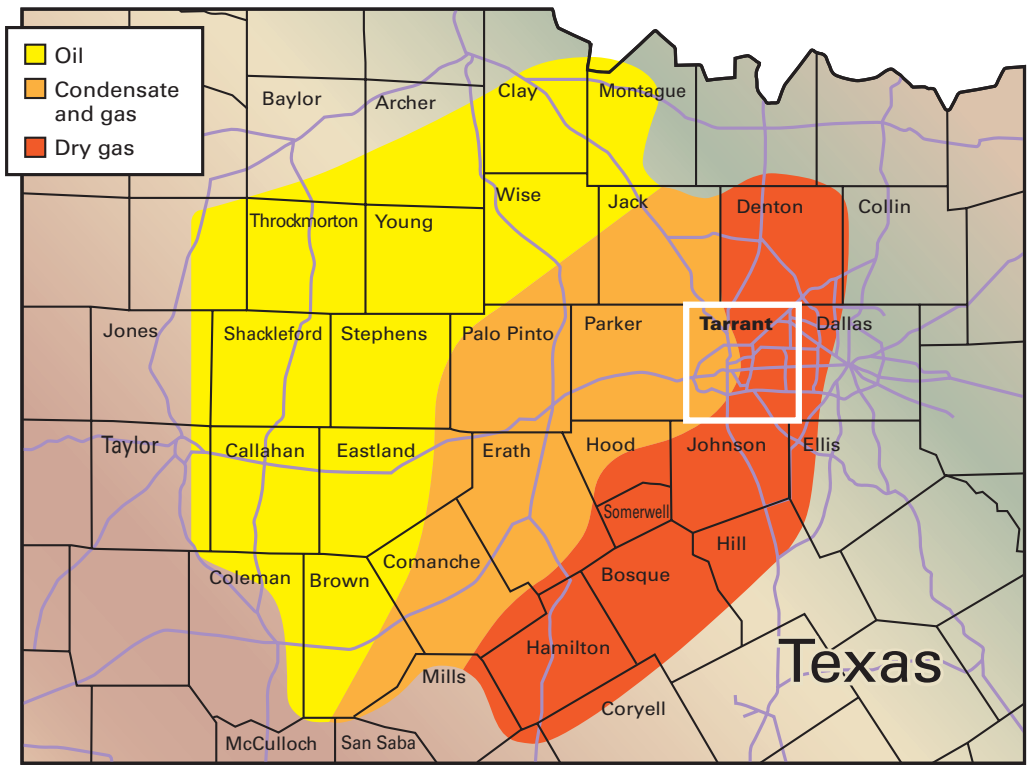
The Barnett shale formation is the grandfather of shale gas plays. Much of the technology used in drilling and production of shale gas has been developed on this play. The Barnett shale formation lies around the Dallas-Fort Worth area of Texas (Fig. 2) and produces at depths of 6,500-9,500 ft. The average production rate varies throughout the basin from 0.5 MMscfd to 4 MMscfd with estimates of 300-350 std. cu ft/ton of shale.[1] The most active operators in the region are Chesapeake Energy, Devon, EOG Resources, and XTO.

The initial discovery region was in a core area on the eastern side of the play. As drilling has moved westward, the form of the hydrocarbons in the Barnett shale has varied from dry gas prone in the east to oil prone in the west.

Table 1 shows the composition of four wells in the Barnett. These wells appear from east to west with the eastern most well on the top (Well No. 1). As the table suggests, there is a large increase in the amount of ethane and pro-

TEXAS BARNETT SHALE

Fig. 2




Source: www.oilshalegas.com

BARNETT SHALE GAS COMPOSITION*

Table 1

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
|---|---|---|---|---|---|
| 1 | 80.3 | 8.1 | 2.3 | 1.4 | 7.9 |
| 2 | 81.2 | 11.8 | 5.2 | 0.3 | 1.5 |
| 3 | 91.8 | 4.4 | 0.4 | 2.3 | 1.1 |
| 4 | 93.7 | 2.6 | 0.0 | 2.7 | 1.0 |

*Normalized to the reported compounds. Adapted from Hill, Ronald J.; Jarvie, Daniel M.; Zumberge, John; Henry, Mitchell; and Pollastro, Richard M., "Oil and gas geochemistry and petroleum systems of the Fort Worth Basin," AAPG Bulletin, Vol. 91, No. 4 (April 2007), pp. 445-473.

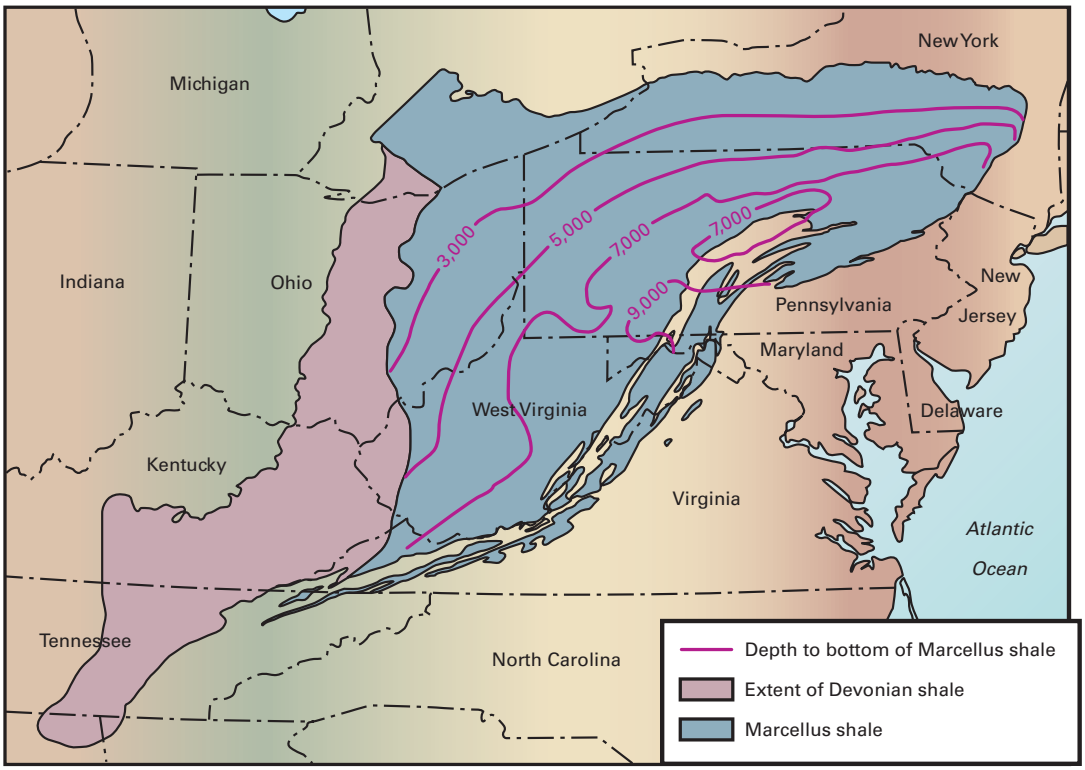
MARCELLUS SHALE GAS COMPOSITION

Table 2

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
|---|---|---|---|---|---|
| 11 | 79.4 | 16.1 | 4.0 | 0.1 | 0.4 |
| 2 | 82.1 | 14.0 | 3.5 | 0.1 | 0.3 |
| 3 | 83.8 | 12.0 | 3.0 | 0.9 | 0.3 |
| 4 | 95.5 | 3.0 | 1.0 | 0.3 | 0.2 |

## MARCELLUS SHALE FAIRWAY

Fig. 3




Source: Geology.com

pane as the wells move west. One well sample on the western edge of the play (Well No. 4) shows a high level—7%—of nitrogen. This level is high enough to require treating, but blending with other gas in the area is the most economical solution.

The gas processing industry has scrambled to keep up with the growth of the Barnett shale. Production has jumped to about 4 bcfd currently from almost nothing in 1999. To sustain this growth, industry has added the equivalent of a 100 MMscfd cryogenic facility to the area every 3 months for 10 years.

Some of the major gas plants processing Barnett shale gas are the Devon Bridgeport (1 bcfd capacity); Quicksilver Cowtown (200 MMcfd) and Corvette (125 MMcfd); Enbridge Weatherford (75 MMcfd); Energy Transfer Godley (300 MMcfd); Crosstex Silver Creek (200 MMcfd), Azle (55 MMcfd), and Goforth (35 MMcfd) plants; and Targa Chico (150 MMcfd) and Shackelford (125 MMcfd). Crosstex has announced plans to add the Bear Creek plant with 200 MMcfd capacity in late 2009.

Most of these plants include compression, $CO_2$ treating with amine units, cryogenic separation, and fractionation.

## FAYETTEVILLE SHALE GAS COMPOSITION

Table 3

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
|---|---|---|---|---|---|
| Avg. | 97.3 | 1.0 | 0 | 1.0 | 0.7 |

## NEW ALBANY SHALE GAS COMPOSITION*

Table 4

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ |
|---|---|---|---|---|
| 1 | 87.7 | 1.7 | 2.5 | 8.1 |
| 2 | 88.0 | 0.8 | 0.8 | 10.4 |
| 3 | 91.0 | 1.0 | 0.6 | 7.4 |
| 4 | 92.8 | 1.0 | 0.6 | 5.6 |

*Compositions normalized to reported compounds; nitrogen content was not reported. Adapted from Martini, Anna M.; Walter, Lynn M.; and McIntosh, Jennifer C., "Identification of microbial and thermogenic gas components from Upper Devonian black shale cores, Illinois and Michigan basins," AAPG Bulletin, Vol. 92, No. 3 (March 2008), pp. 327-339.

The processed gas heads east toward Carthage, Tex., where it can reach the Midwest via the Perryville hub or the Northeast via the Transco or Texas Eastern pipeline, or the Southeast via the Transco or Florida Gas pipeline.

With the richness of the gas, the Barnett plants remove about 3.5 gal/Mcf of NGL. Based on current 4-bcfd gas production, about 325,000 b/d of NGLs are produced.

One of the greatest challenges to gas processing in the Barnett shale region is operating in an urban environment. As an example, the town of Flower Mound has an extensive list of regulations for the gas processing industry for operations within its city limits. These regulations cover appearance (color, landscaping, fences, and lighting) as well as operations (equipment height and noise level). These extensive regulations force the gas plants to move to less densely populated areas when possible.

### *Marcellus*

The Marcellus shale lies in western New York, Pennsylvania, Ohio, and West Virginia (Fig. 3) and has tremendous potential. It is shallow at depths of 2,000-8,000 ft and 300-1,000 ft thick. Initial production rates have been reported in the 0.5-4 MMscfd range with estimates

of 60-100 std. cu ft/ton of shale.

Table 2 shows the composition for four natural gas wells in the Marcellus shale. The gas composition varies across the field, much as it does in the Barnett: The gas becomes richer from east to west.

From a gas processing point of view, the Marcellus region does not have the gas blending luxury of the Barnett shale because there is little infrastructure. The Marcellus is blessed, however, with little $CO_2$ and nitrogen. The greatest obstacle for the area—a lack of facilities to dispose of wastewater and completion fluids—has limited growth in this region. A complex terrain of hills, trees, and streams creates access and environmental obstacles to drilling and production. Operators compensate with custom rigs to reduce footprints.

Most existing Pennsylvania and Northern Appalachian gas is dry and requires no removal of NGLs for pipeline transportation. Early indications are that the Marcellus gas has sufficient liquids to require processing.

Markwest Energy Partners recently announced installation of a 30-MMscfd refrigeration unit to process Marcellus gas from Range Resources. Markwest is also currently constructing a 30-MMscfd cryogenic processing plant expected to commence operations late in first-quarter 2009. An additional 120 MMscfd cryogenic plant with a fractionation train is planned for completion in late 2009. The liquid propane will be marketed regionally.

Some anticipate that the Marcellus shale could hold as much gas as the Texas Barnett shale. If this is the case, gas processing could generate substantial volumes of NGLs for the region with no clear market or access to the Texas Gulf Coast.

FAYETTEVILLE SHALE

Fig. 4


Source: www.oilshalegas.com

## *Fayetteville shale*

The Fayetteville shale is an unconventional gas reservoir on the Arkansas side of the Arkoma basin (Fig. 4). The shale ranges in thickness from 50-550 ft at a depth of 1,500-6,500 ft and is estimated to hold between 58-65 bcf/sq mile.[2]

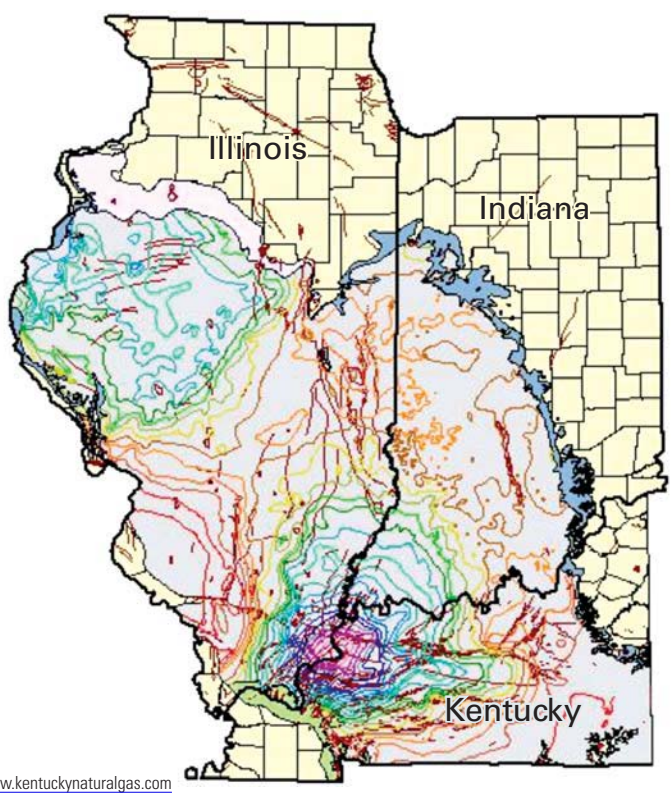
Reported initial production rates are 0.2-0.6 MMscfd for vertical wells and 1.0-3.5 MMscfd for horizontal wells. In 2003 Southwestern Energy discovered the play and has increased its production to about 500 MMcfd.

Table 3 shows gas composition of one area of the Fayetteville shale. The gas primarily requires only dehydration to meet pipeline specifications. Lack of infrastructure also has limited growth of this area. Additional pipeline capacity is on the way with the Texas Gas 1.3-bcfd Fayetteville lateral under construction.

An additional 2 bcfd of pipeline

NEW ALBANY SHALE

Fig. 5




Source: www.kentuckynaturalgas.com

capacity has been announced by Kinder Morgan Energy Partners LP and Energy Transfer Partners LP, which is scheduled for completion in 2010-11. Southwestern Energy and Chesapeake have agreed to 10-year commitments to use the 187-mile line.

The full scope of the Fayetteville shale is still unknown. Southwestern Energy has about 850,000 acres leased, while the remainder of the industry has an additional 1 million acres.

## New Albany

The New Albany shale is a black shale in Southern Illinois extending through Indiana and Kentucky (Fig. 5). It is 500-4,900 ft deep and 100-400 ft thick. Vertical wells typically produce 25-75 Mscfd initially, while horizontal wells can have initial production rates of up to 2 MMscfd.

Table 4 shows the composition from four wells in Meade County. In this region the gas contains 8-10% $CO_2$. Low flow rates of wells in the New Albany shale require that production from many wells must be combined to warrant processing the gas.

NGAS Resources announced in October 2008 that it completed field gathering and gas processing facilities in Christian County, Kentucky. The processed gas from 26 wells is flowing into the Texas Gas interstate pipeline. The company has two rigs running in the area with expected recoveries of 135-200 million cu ft/well.

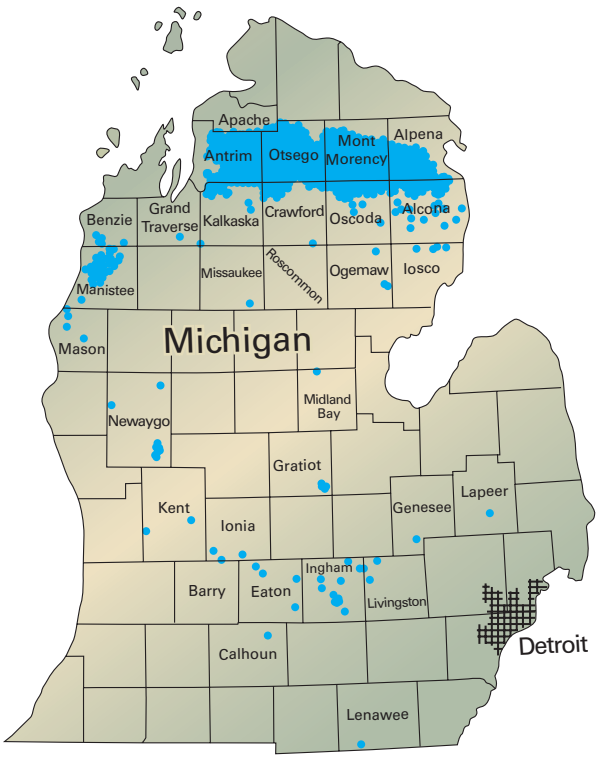
## Antrim

The Antrim is a shallow shale gas play in Michigan (Fig. 6) whose development accelerated as a result of unconventional-gas tax incentives of the 1980s. Today, more than 9,000 wells in the Antrim shale have cumulatively produced 2.5 tcf. Individual well production ranges from 50 to 60 Mscfd. Despite these small initial production rates, extremely long well life resulted in substantial production over the life of the well.

The Antrim shale is unique because the gas is predominately biogenic:

ANTRIM SHALE

Fig. 6




Methane is created as a by-product of bacterial consumption of organic material in the shale. Large volumes of associated water are produced, requiring central production facilities for dehydration, compression, and disposal.

Table 5 shows the compositions of the gas produced from four wells in this area. The $CO_2$ level in these samples varies 0-9%. $CO_2$ is a naturally occurring byproduct of shale gas produced by desorption. As a result, the $CO_2$ levels in produced Antrim gas steadily grow during a well's productive life, eventually topping 30% in some areas.

MarkWest is the dominant gas processor in this region with 340 MMcfd of capacity at five plants (Kenova, Maytown, Boldman, Kermit, and Cobb). Residue gas is delivered to Columbia Gas Transmission while the NGLs move to the Siloam fractionators for further processing and then are sold by truck, rail, or barge.

## Haynesville

The Haynesville shale play is the newest and hottest shale area to be developed. It lies in northern Louisiana and East Texas (Fig. 7). It is deep (10,000+ ft), hot (350° F. bottomhole temperature), and exhibits high pressure (3,000-4,000 psi). The wells have shown initial production rates of 2.5-20+ MMscfd, with estimates of 100-330 std. cu ft/ton of shale. The Haynesville shale area is believed to hold large potential and projected to draw resources away from the other shale plays in the near future.

Table 6 shows a field average concentration for the

ANTRIM SHALE GAS COMPOSITION*

Table 5

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
|---|---|---|---|---|---|
| 1 | 27.5 | 3.5 | 1.0 | 3.0 | 65.0 |
| 2 | 57.3 | 4.9 | 1.9 | 0 | 35.9 |
| 3 | 77.5 | 4.0 | 0.9 | 3.3 | 14.3 |
| 4 | 85.6 | 4.3 | 0.4 | 9.0 | 0.7 |

*Normalized to the reported compounds. Adapted from Martini, Anna M.; Walter, Lynn M.; Ku, Tim C.W.; Budai, Joyce M.; McIntosh, Jennifer C.; and Schoell, Martin, "Microbial production and modification of gases in sedimentary basins: A geochemical case study from a Devonian shale gas play, Michigan basin," AAPG Bulletin, Vol. 87, No. 8 (August 2003), pp. 1,355-375.

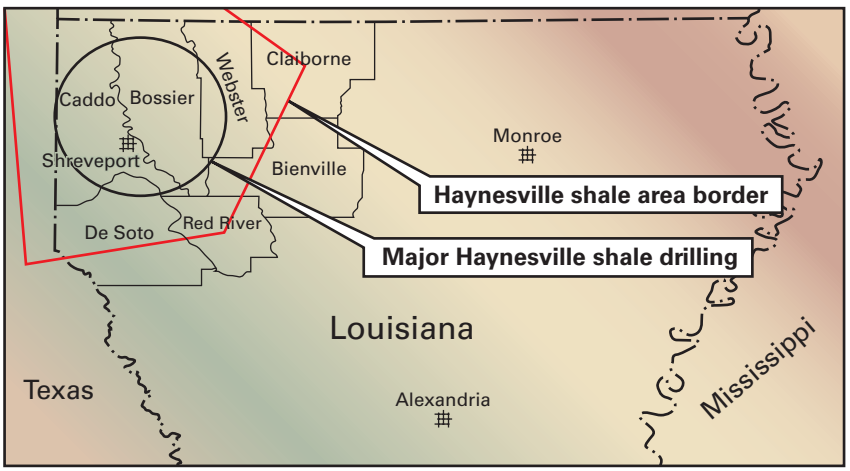
HAYNESVILLE SHALE GAS COMPOSITION

Table 6

| Well | $C_1$ | $C_2$ | $C_3$ | $CO_2$ | $N_2$ |
|---|---|---|---|---|---|
| Avg. | 95.0 | 0.1 | 0 | 4.8 | 0.1 |

HAYNESVILLE AREA

Fig. 7




Source: www.oilshalegas.com

Haynesville play. This gas requires treating for $CO_2$ removal. Operators in this field are using amine treating to remove the $CO_2$ with a scavenger treatment on the tail gas to remove the $H_2S$. Most of the treating is currently performed with traditional amine units with 60-100 gpm capacities. These units are rented or purchased. Most of the processed gas enters the Carthage system, which then distributes it across the country.

One of the biggest problems faced by gas processors in the Haynesville area is the large production addition from each well as it is brought on line. Plants that are oversized today become undersized tomorrow. Area operators suggest designing units that scale up and down easily during the growth process. This includes units that employ valve trays, variable speed pumps, and multiple trains.

Chesapeake announced that the initial production rate for the last seven horizontal Haynesville wells averaged 16 MMscfd each. If the pipeline announcements are any clue, industry is anticipating a scramble for processing plants for Haynesville much like the rapid growth of the Barnett.

DCP Midstream Partners and M2 Midstream LLS have recently announced a joint venture for a 1.5-bcfd pipeline to be completed in early 2010. Energy Transfer Partners and Chesapeake announced plans for the 42-in. Tiger pipeline to connect from Carthage, Tex., to near Delhi, La., to be completed by mid-2011. ✦

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# US LNG imports in 2008 signal unexpected role for gas markets

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Recent experience and forecasts have shown a narrowing gap between domestic natural gas supply and consumption, unfavorable oil-to-gas price disconnects, increasing competition for limited liquefaction capacity, and dampened domestic demand due to the current economic decline. As a result, it seems likely that LNG's role in meeting the US supply shortfall will be a supportive one in a highly competitive international gas market.

Given these market conditions, a merchant-based regasification strategy that depends on the availability of spot LNG cargoes is unlikely to be successful. Liquefaction capacity owners will retain a portion of the opportunity to capture geographic price differentials instead of selling it entirely to LNG marketers.

Such a role—and the associated costs of building expensive LNG delivery systems for other than base-load purposes—is unlikely to attract the levels of sustainable investment required for development of an extensive US LNG market.

Since 1959, when the Methane Pioneer demonstrated the feasibility of transporting LNG in a transoceanic trade, there have been two major waves of enthusiasm for projects to bring LNG from international sources into the US natural gas market.

## First wave

The first occurred in the 1970s, a period of rising natural gas prices and nearly universal forecasts of even higher energy costs. Beginning in November 1971 with the first deliveries of LNG from Algeria's Sonatrach to Distrigas at Everett, Mass., projects were developed over 1971-82 to deliver large volumes of LNG to terminals at Elba Island, Ga., Lake Charles, La., and Cove Point, Md.

These large, capital-intensive ventures involved the integrated construction of liquefaction and gasification facilities as well as fleets of expensive cryogenic tankers. Fig. 1 shows these projects delivered relatively modest volumes to the US market for several years, reaching peak delivery in 1979 of 253 bcf, which was 1.3% of US natural gas consumption that year.

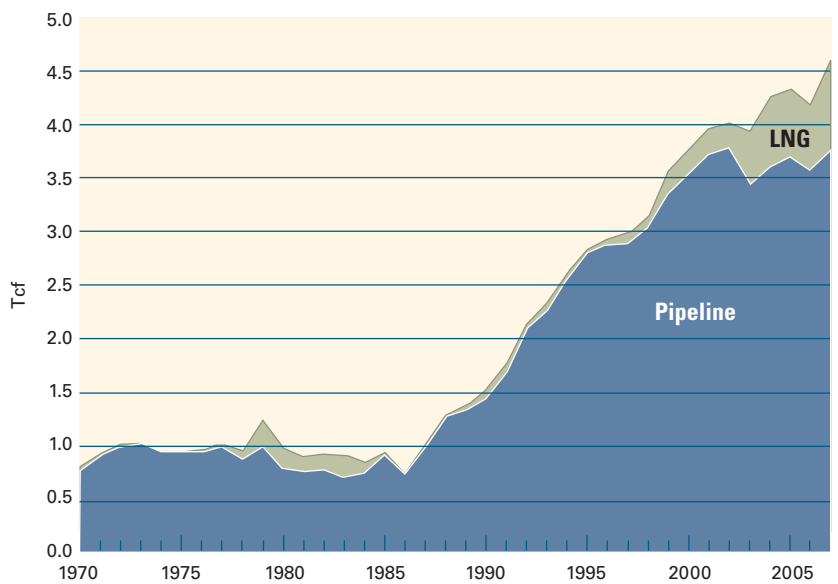
As these projects were getting under way, however, federal regulatory initiatives began to change the fundamentals of the US natural gas industry. The Natural Gas Policy Act of 1979 was the first in a series of regulations that led to a broad restructuring of the US natural gas industry.[1]

These structural reforms precluded a utility's ability to pass on the costs of more expensive contracted-for supplies when lower-cost supplies were available on the spot market and could be transported under the newly minted expedient of "open access." With financial support for projects of that era typically long-term, take-or-pay arrangements, this evolution changed the US LNG industry.

Exacerbating the situation were

US NATURAL GAS IMPORTS: 1970-2007

Fig. 1




Source: US EIA, Annual Energy Review 2007

contractual disputes over price with Algeria's Sonatrach, the sole producer and supplier of LNG for these projects, and national security concerns about heavily relying on foreign suppliers of energy for US consumption. Although LNG's peak year of supply saw imported natural gas from countries other than Canada or Mexico account for only 1.3% of US consumption, lengthy gasoline lines as the result the 1973 embargo and dislocations caused by the 1979 Iranian Revolution remained in the minds of American consumers and energy planners.

Owners at the Cove Point and Elba Island LNG terminals mothballed them in 1980, and the terminal at Lake Charles shut down shortly after its completion in 1982. By 1987, there were no deliveries of LNG to the US and only minimal deliveries throughout the 1990s.

## Second wave

By the early 2000s, higher gas prices, declining domestic production, and expectations of slowing Canadian imports once again rekindled interest in bringing LNG to US markets. Figs. 2 and 3, respectively, present a spike in Henry Hub natural gas prices and deteriorating production profiles of major US production areas (with the exception of the Rockies).[2]

Accordingly, in 2003 the US Energy Information Administration forecast that by 2015, LNG would become the largest source of gas imported into the US, rising to 39% in 2010 from 5% of imports in 2002.[3]

That optimism reflected use of the four existing US terminals, three of which had been mothballed since the 1980s, as well as a flood of proposed regasification projects. By June 2004, there were 27 new regasification terminals in various stages of investor and governmental approval for a combined capacity of 31 bcfd,[4] far more than expected demand.[5]

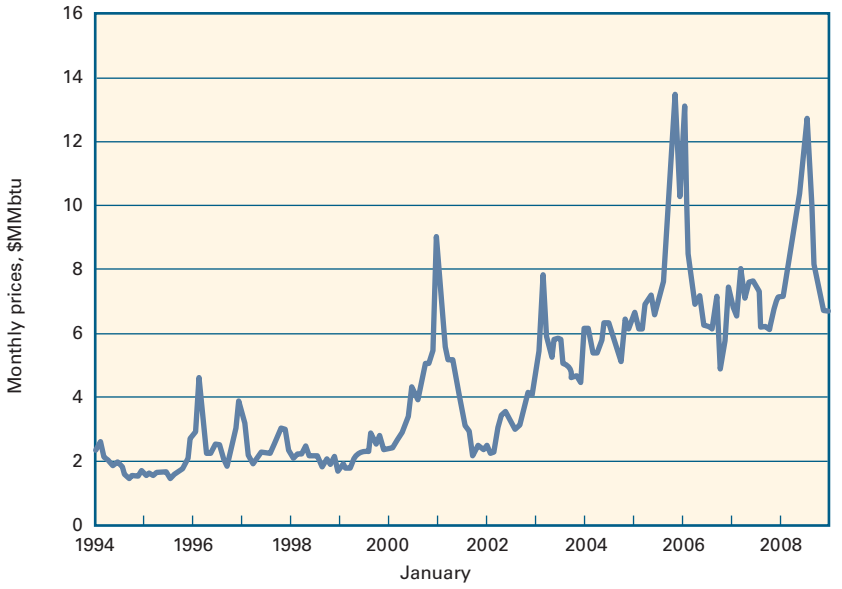
## Recent experience

2007 was the peak year for LNG imports to the US with deliveries of 771 bcf, accounting for 16.7% of natural gas imports but still only a modest 3.3% of US natural gas consumption.[6] In 2008, stronger demand for LNG in Europe and Asia diverted supplies from the US. Imports for the first 10 months of 2008 were only 298 bcf, about half of recent forecasts.

It may be argued that this downturn is cyclical in the development of a long-term LNG market and will be short. Several temporary and fundamental factors, however, emerged in 2008 to cause this bearish year for US LNG. Price, supply, and demand—while obvi-

### HENRY HUB NATURAL GAS PRICES

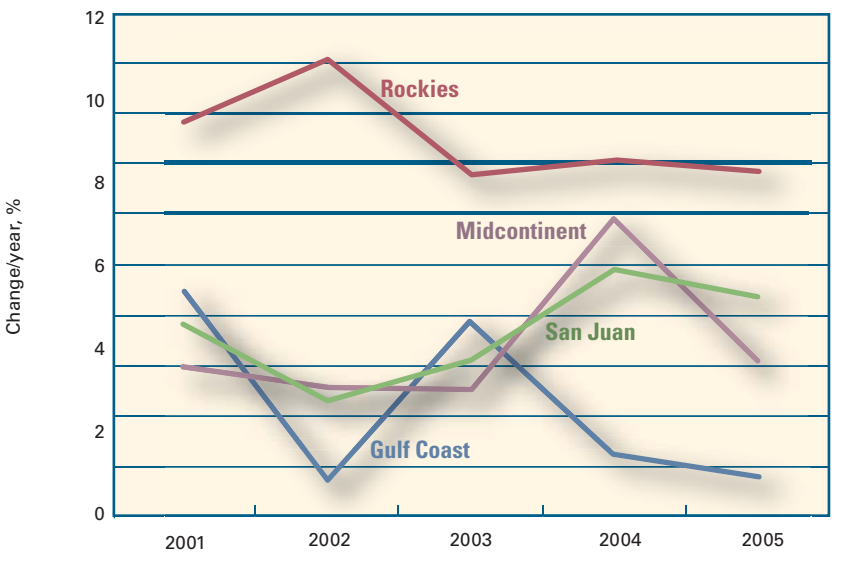
Fig. 2




Source: US Federal Reserve Bank, St. Louis; http://research.stlouisfed.org

### PRODUCTION CHANGES IN KEY US REGIONS

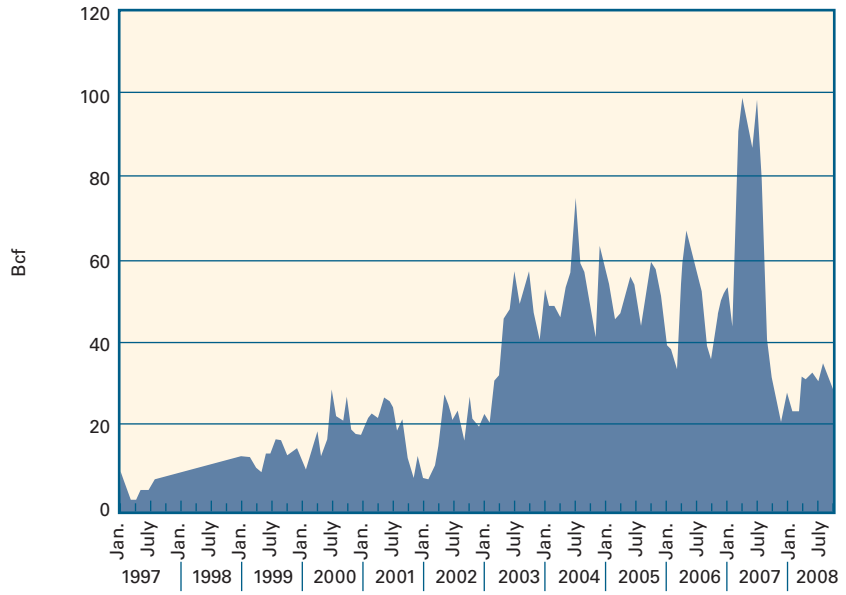
Fig. 3




Source: US EIA; http://tonto.eia.doe.gov

## US LNG IMPORTS SINCE 1997

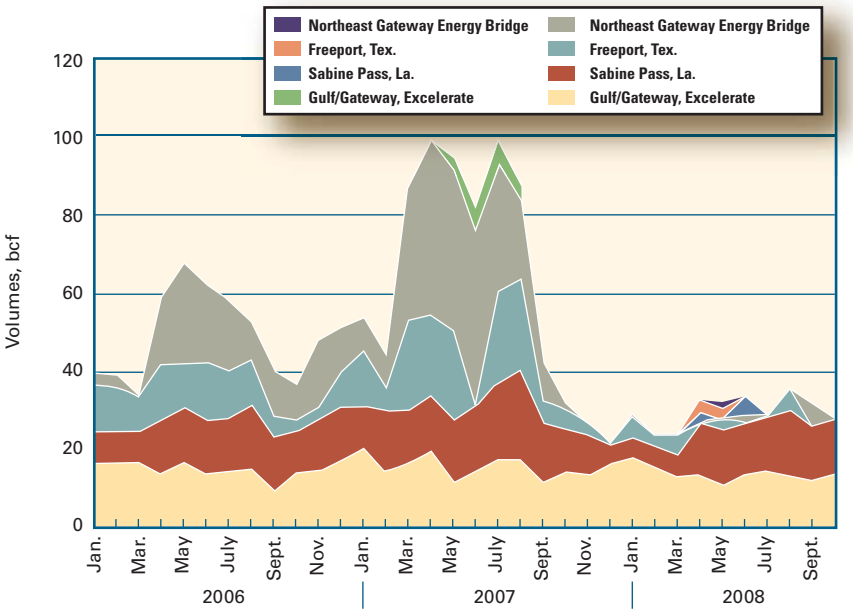
Fig. 4




Source: US EIA; http://tonto.eia.doe.gov

## US LNG IMPORTS: 3 YEARS

Fig. 5




Source: Derived from DOE Office of Fossil Energy data; updated through Dec. 5, 2008

ously linked—each experienced direct independent shocks that depressed US LNG imports in 2008. The future of US LNG rests with how persistent and powerful these dampening forces are in the face of significant new liquefaction capacity coming online and rising US natural gas demand.

### Global gas pricing

The US competes with other importers, especially southern Europe and Japan,[7] for LNG cargoes. Natural gas in these two markets is generally linked to oil prices, unlike in the US where natural gas prices are correlated to oil but through substitution and production effects vs. formula pricing. US natural gas prices are linked to prices at Henry Hub, the delivery point on the Louisiana Gulf Coast for natural gas futures contracts on the New York Mercantile Exchange. Henry Hub prices, although rising until recently, have generally been lower than prices linked to imported crude oil, as they are in Asia, or to other competing fuels, as they are in Europe.

With the run-up in crude price—NYMEX prompt month crude futures hit an intraday high of $147.27/bbl on July, 11, 2008,[8] oil and gas prices disconnected in 2008 (Fig. 6).

The historic relationship between a barrel of crude oil and an MMbtu of gas is 8.1.[9] In 2008, however, it averaged 11.5. This disconnect, combined with the nature of international oil-based formula pricing, meant that natural gas prices were much higher in Europe and Japan than in the US.

The pricing environment was further stressed by a demand shock in Japan, the world's largest LNG importer. In January 2008, a combination of cold weather and an extended nuclear-generation outage increased Japan's need for replacement gas generation, driving LNG spot cargoes close to $20/MMbtu.[10] These pricing dynamics explain why Cheniere Energy's terminal at Sabine Pass, Tex., which has the largest US regasification capacity, did not receive a commercial delivery in 2008.

The collapse of crude prices in the last months of 2008 brought the oil-to-gas relationship back within normal ranges that, if sustained, will favor a more competitive domestic LNG market in 2009 (Fig. 7).

### Supply

US LNG imports were further dampened in 2008 by two key elements:

1. The near-term shortage of global liquefaction capacity.
2. The rapid increase in domestic production largely related to unconventional gas production as an alternative to imported LNG.

## Liquefaction capacity

Regasification capacity, which is less expensive and time consuming to construct than liquefaction capacity, has substantially outstripped the availability of new supply.[10]

Global liquefaction capacity has been slow to come online, with only a 1.9% increase during first-half 2008 compared to the same period in 2007. This slow growth is due both to delayed completion of in progress projects and cancellation of new projects.

There were significant project completion delays in 2008, including Tangguh, Sakhalin 2, Yemen LNG, Qatargas 2 Train 2, and RasGas 3 Train 1.[11] Stretched vendor manufacturing capacity has led to longer delivery times. Governmental and lender requirements have become more onerous, extending the time for permitting and financing closure. And detailed engineering with less experienced personnel has also extended project timelines. Industry reports are that Qatar actually shut down some of its gas-to-liquids projects due to overextension of limited worldwide manufacturing and engineering capacity.

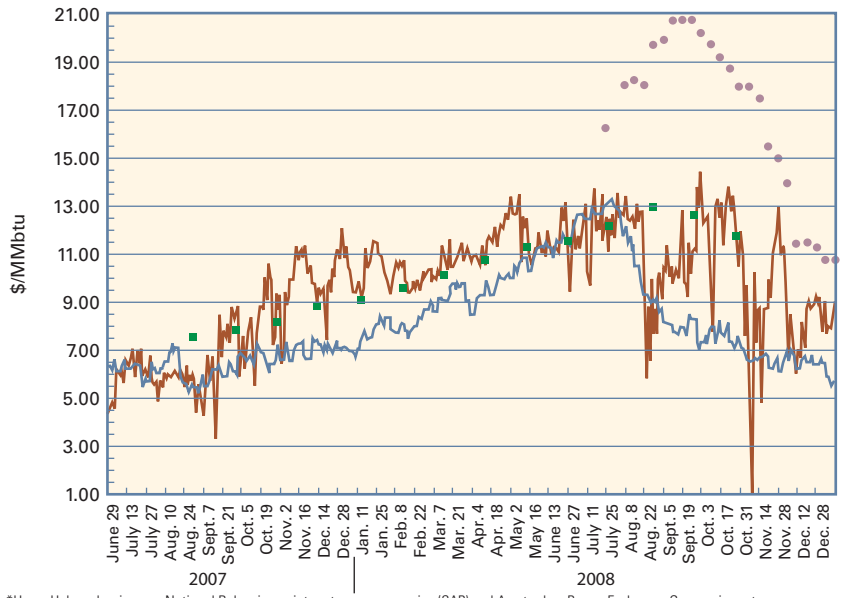
As for new projects, there are a few reasons for the slower entry of new LNG liquefaction projects. The first is the increased cost of capacity, from previous levels of about $200/metric ton to more than $600/metric ton in many cases. This reflects engineering, manufacturing, and construction costs that are higher than before. Secondly, oil companies have been cautious in making investments based on gas prices that might not be sustainable.

Finally, some projects that were being developed have stalled or been delayed due to government intervention; examples include Russia-Sakhalin (delayed), Iran-South Pars (canceled), Algeria-Arzew and Skikda (delayed), and Bolivia-Pacific (canceled).

In combination with previously mentioned pricing issues, this regasification-to-liquefaction capacity imbalance has left the US as the global swing market for excess LNG supply. This limitation will continue to be a bearish factor on the growth of US LNG imports.

INTERNATIONAL PRICE SPREADS: 2007-08*

Fig. 6




*Henry Hub cash prices vs. National Balancing point system average price (SAP) and Amsterdam Power Exchange; German import price (monthly average) and the RIM spot LNG index. Source: LNG Week in Review, NATS Weekly Summary Report, Dec. 12, 2008

## Unconventional gas

While the gap between US and international gas prices was exacerbated by the historic disconnect between oil and gas prices, that was just one side of the equation. A spike in unconventional gas production increased US domestic production to a 20-year high of just more than 20 tcf.[12]

This increase in US domestic gas production was driven largely by rapid growth in unconventional gas production (shale gas, tight sands, and coalbed methane). Unconventional gas production–primarily shale plays–over the last couple of years has reversed a long-term trend of flat-to-declining production.

Unconventional gas production is not new; it has been around for decades. The combination of sustained higher gas prices, however, and breakthroughs in production technology has opened up vast new US natural gas reserves that are economically feasible to exploit.

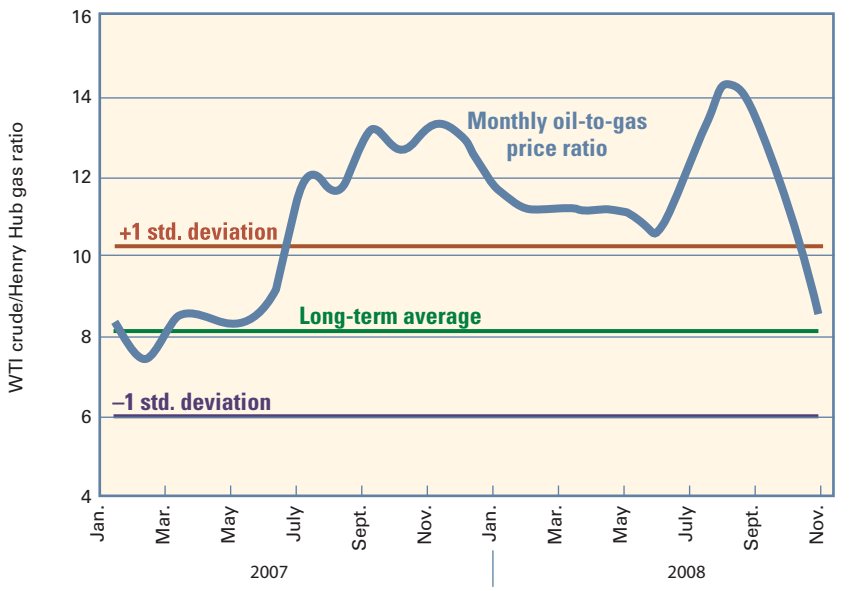
Unconventional gas production comprised about 50% of US domestic production in 2008. Estimates of future unconventional gas production are invariably bullish but vary widely. Consensus estimates from leading forecasters expect shale production to grow at 10%/year through 2015, with all sources of unconventional gas accounting for about 65% of total US production.[13]

Most of this new supply, which was not anticipated during the flood of US regasification terminal projects in the mid 2000s, will displace once-planned LNG imports. Some forecasters have suggested that the unconventional base is substantial enough nearly to eliminate the need to bring LNG to the US through 2030.[14]

US LNG import full-cycle costs are about $3.50-4.50/MMbtu,[15,16] while those for US shale production, depending on basin, are about $5.40-$7.50/MMbtu.[17] While these full-cycle costs of importing LNG are less than for US domestic unconventional gas production, the substantial imbalance of global regasification to liquefaction capacity and international pricing dynamics addressed previously left the US in 2008 the market of last resort for spot LNG.

US OIL-GAS PRICE RATIO: 2007-08

Fig. 7




Source: US EIA; http://tonto.eia.doe.gov

## US gas demand

At the beginning of 2008, EIA projected that domestic consumption would rise year-over-year by more than 3%. But consumption increased at a fraction of that, by only 0.64%.

The National Bureau of Economic Research declared that the US has been in recession since December 2007.[18] Over the last decade, the US economy has required about 500 MMbtu/$1 of gross domestic product. The recession has reduced demand, especially in many gas-intensive industries, including petrochemicals, fertilizer, steel, and other automobile-related industries. There have been a number of high-profile industrial plant closures in 2008, including, for example, that Chrysler would cease production at all its US plants for at least 1 month.[19]

EIA's Short-Term Energy Outlook (Dec. 15, 2008) projected that natural gas consumption, which had been expected to grow by only 0.5% in 2008, will remain flat in 2009. Slight growth is expected in the residential, commercial, and electric-power sectors, but the worldwide economic downturn will result in a 2.4% decline in 2009's consumption of natural gas by industry.[20]

## Impact on investment

The import experience of 2008 and uncertain prospects for substantial near-term improvement left a wake of US LNG regasification causalities both large and small. Cheniere Energy, the best example of a US LNG pure play company, has seen its stock crushed and the enterprise forced onto life support with a distressed financing arrangement.

Other players experienced related challenges. Smaller project development players such as Quoddy Bay LNG[21] and Calhoun LNG also felt the pinch, as the near-term fundamentals and credit crisis have limited interest from outside investors. BP cited LNG economic factors in its decision in late 2008 to postpone plans for its Crown Landing terminal along the Delaware River in New Jersey.

This situation has collapsed the business model pursued by some players, like Cheniere,[22] that depended on the availability of spot cargoes both from a tolling and marketing fee standpoint. In contrast, more successful business models took the approach of matching long-term commitments to regasification capacity, such as Sempra's 1-bcfd Energía Costa Azul terminal, which, in advance of construction, locked up commitments for 100% of its capacity via a mix of supply from Indonesia's Tangguh and capacity payments from Shell.[23] Other examples of this approach include the Freeport, Cove Point expansion, and Elba expansion projects. Regardless of the current business model employed, long-term viability of the US LNG industry depends on favorable natural gas pricing.

## Future

The potential for projects currently planned or in their initial stages of operation is being revisited in light of conditions that manifested themselves in 2008 but may indicate longer-term structural changes in the US economy.

Accordingly, the longer-term future of US LNG rests with how persistent and powerful these dampening forces are in terms of prospects for significant new liquefaction capacity as well as for the resurgence of demand for natural gas demand that will result from economic recovery over the coming decades.

The question also arises whether the experience of 2008 was part of a developmental business cycle or did it indicate structural change in the price, supply, and demand relationships for LNG that will discourage future investment in the sector.

Having seen two disappointing waves of interest in the concept of importing LNG, investors (who are far from obliged to risk capital on energy ventures) may doubt whether the future role of LNG in the US supply mix is compatible with constructive investment. ✦

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3. EIA, The Global Liquefied Natural Gas Market: Status & Outlook. December 2003, p. 29.

4. EIA, "US LNG Markets and Uses:

June 2004 Update," pp. 7-8.

5. In 2004, EIA's Annual Energy Outlook forecast that LNG imports would grow to 2.2 tcf (6.0 bcfd) in 2010 and 4.8 tcf (13.2 bcfd) in 2025 from 0.2 tcf in 2002 (an average daily volume of 0.5 bcf).

6. US Energy Information Administration.

7. BP 2008 Statistical Energy Review, p. 30; www/bp.com.

8. Reuters, "Oil hits record above $147," July 11, 2008.

9. 1994-2007 using WTI spot and Henry Hub spot monthly averages, as cited in http://tonto.eia.doe.gov; and http://research.stlouisfed.org.

10. Platts, Global LNG Outlook, "LNG regas capacity is outstripping new liquefaction plant at a rapid rate," Mar. 12, 2008; www.platts.com.

11. FACTS Global Energy, Oct. 8, 2008; http://globallnginfo.com.

12. EIA, US Natural Gas Marketed Production; http://tonto.eai.doe.gov.

13. Wood Mackenzie's Long-Term View, August 2008; www.woodmacresearch.com.

14. Gas Daily, "Economists: Shale gas boom will cut need for LNG imports," Dec. 8, 2008. Reporting on Rice World Gas Trade Model, presented by Hartley and Medlock at the US Association of Energy Economists conference in New Orleans, November 2008.

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18. National Bureau of Economic Research, "Determination of the December 2007 Peak in Economic Activity," Dec. 11, 2008.

19. CNN, "Chrysler shuts down all production," Dec. 17, 2008.

20. EIA, "Short Term Energy Outlook," Dec. 15, 2008.

21. Energy Current, "Quoddy Bay LNG requests additional delay," July 24, 2008.

22. While Cheniere has long-term fixed take-or-pay terminal-use agreements with Chevron and Total, the value of these agreements was spun off into a limited partnership: Cheniere Energy Partners LP.

23. http://www.sempralng.com/Pages/Terminals/Energia/default.htm.

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## Imports of crude and products

| | Districts 1–4 | | District 5 | | Total US | | |
|---|---|---|---|---|---|---|---|
| | 2-20 2009 | 2-13 2009 | 2-20 2009 | 2-13 2009 | 2-20 2009 | 2-13 2009 | *2-22 2008 |
| | 1,000 b/d | | | | | | |
| Total motor gasoline | 750 | 811 | 55 | 15 | 805 | 826 | 1,354 |
| Mo. gas. blending comp. | 648 | 670 | 0 | 15 | 648 | 685 | 843 |
| Distillate | 282 | 477 | 0 | 0 | 282 | 477 | 194 |
| Residual | 306 | 325 | 0 | 139 | 306 | 464 | 181 |
| Jet fuel–kerosine | 60 | 16 | 0 | 7 | 60 | 23 | 132 |
| Propane–propylene | 157 | 154 | 57 | 47 | 214 | 201 | 254 |
| Other | 471 | 83 | 22 | (55) | 493 | 28 | 586 |
| **Total products** | **2,674** | **2,536** | **134** | **168** | **2,808** | **2,704** | **3,544** |
| **Total crude** | **7,619** | **7,761** | **1,150** | **1,032** | **8,769** | **8,793** | **9,958** |
| **Total imports** | **10,293** | **10,297** | **1,284** | **1,200** | **11,577** | **11,497** | **13,502** |

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

## Purvin & Gertz LNG netbacks—Feb. 27, 2009

| Receiving terminal | Liquefaction plant | | | | | |
|---|---|---|---|---|---|---|
| | Algeria | Malaysia | Nigeria | Austr. NW Shelf | Qatar | Trinidad |
| | $/MMbtu | | | | | |
| Barcelona | 11.05 | 7.76 | 10.27 | 7.66 | 9.59 | 10.20 |
| Everett | 4.11 | 2.27 | 3.81 | 2.38 | 2.71 | 4.34 |
| Isle of Grain | 3.91 | 1.95 | 3.32 | 1.86 | 2.39 | 3.36 |
| Lake Charles | 1.98 | 0.42 | 1.77 | 0.55 | 0.68 | 2.52 |
| Sodegaura | 4.58 | 7.67 | 4.84 | 7.41 | 6.80 | 4.07 |
| Zeebrugge | 8.25 | 4.80 | 6.80 | 4.77 | 5.38 | 6.94 |

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 | | Jet fuel, kerosine | Fuel oils | | Propane–propylene |
|---|---|---|---|---|---|---|---|
| | | Total | Blending comp.[1] | | Distillate | Residual | |
| | 1,000 bbl | | | | | | |
| PADD 1 | 13,470 | 58,837 | 37,325 | 10,315 | 50,444 | 12,230 | 1,841 |
| PADD 2 | 83,985 | 53,919 | 21,429 | 8,141 | 35,902 | 1,179 | 12,884 |
| PADD 3 | 182,873 | 68,489 | 38,208 | 12,361 | 38,922 | 16,990 | 23,373 |
| PADD 4 | 14,981 | 6,917 | 2,444 | 444 | 3,436 | 256 | [1]1,291 |
| PADD 5 | 56,038 | 27,180 | 22,844 | 9,213 | 12,930 | 5,742 | — |
| **Feb. 20, 2009** | **351,347** | **215,342** | **122,250** | **40,474** | **141,634** | **36,397** | **39,389** |
| **Feb. 13, 2009** | **350,630** | **218,664** | **125,195** | **40,957** | **140,752** | **36,320** | **40,012** |
| **Feb. 22, 2008[2]** | **308,505** | **232,619** | **116,074** | **40,083** | **119,952** | **36,672** | **31,583** |

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

## Refinery report—Feb. 20, 2009

| District | Refinery operations | | Refinery output | | | | |
|---|---|---|---|---|---|---|---|
| | Gross inputs | Crude oil inputs | Total motor gasoline | Jet fuel, kerosine | Fuel oils | | Propane–propylene |
| | | | | | Distillate | Residual | |
| | 1,000 b/d | | | | | | |
| PADD 1 | 1,163 | 1,184 | 2,371 | 78 | 356 | 131 | 52 |
| PADD 2 | 3,233 | 3,208 | 2,291 | 209 | 1,025 | 61 | 214 |
| PADD 3 | 6,540 | 6,339 | 2,536 | 642 | 2,136 | 283 | 603 |
| PADD 4 | 569 | 551 | 301 | 29 | 176 | 8 | [1]151 |
| PADD 5 | 2,835 | 2,654 | 1,438 | 406 | 520 | 125 | — |
| **Feb. 20, 2009** | **14,340** | **13,936** | **8,937** | **1,364** | **4,213** | **608** | **1,020** |
| **Feb. 13, 2009** | **14,497** | **14,143** | **8,765** | **1,296** | **4,147** | **519** | **1,077** |
| **Feb. 22, 2008[2]** | **14,765** | **14,624** | **8,778** | **1,496** | **3,888** | **628** | **1,061** |
| | **17,621 Operable capacity** | | **81.4% utilization rate** | | | | |

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

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

OIL&GAS JOURNAL online research center

## OGJ crack spread

| | *2-27-09 | *2-29-08 | Change | Change, % |
|---|---|---|---|---|
| | $/bbl | | | |
| **SPOT PRICES** | | | | |
| Product value | 50.68 | 109.29 | –58.61 | –53.6 |
| Brent crude | 42.70 | 100.11 | –57.41 | –57.3 |
| Crack spread | 7.98 | 9.18 | –1.20 | –13.0 |
| **FUTURES MARKET PRICES** | | | | |
| **One month** | | | | |
| Product value | 50.38 | 110.62 | –60.25 | –54.5 |
| Light sweet crude | 42.18 | 100.84 | –58.66 | –58.2 |
| Crack spread | 8.20 | 9.79 | –1.59 | –16.2 |
| **Six month** | | | | |
| Product value | 54.47 | 112.93 | –58.46 | –51.8 |
| Light sweet crude | 48.74 | 99.23 | –50.49 | –50.9 |
| Crack spread | 5.73 | 13.70 | –7.96 | –58.1 |

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

## OGJ GASOLINE PRICES

| | Price ex tax 2-25-09 | Pump price* 2-25-09 | Pump price 2-27-08 |
|---|---|---|---|
| | ¢/gal | | |
| (Approx. prices for self-service unleaded gasoline) | | | |
| Atlanta | 147.2 | 193.7 | 322.4 |
| Baltimore | 149.8 | 191.7 | 311.1 |
| Boston | 147.9 | 189.8 | 311.0 |
| Buffalo | 134.8 | 195.7 | 334.0 |
| Miami | 141.2 | 192.8 | 336.0 |
| Newark | 152.1 | 184.7 | 296.8 |
| New York | 121.1 | 182.0 | 312.4 |
| Norfolk | 146.3 | 184.7 | 306.5 |
| Philadelphia | 148.1 | 198.8 | 318.3 |
| Pittsburgh | 158.0 | 208.7 | 315.9 |
| Wash., DC | 169.5 | 207.9 | 318.4 |
| PAD I avg | 146.9 | 193.7 | 316.6 |
| Chicago | 144.8 | 209.2 | 341.9 |
| Cleveland | 145.8 | 192.2 | 304.0 |
| Des Moines | 143.8 | 184.2 | 306.3 |
| Detroit | 131.8 | 191.2 | 307.3 |
| Indianapolis | 130.8 | 190.2 | 310.4 |
| Kansas City | 142.2 | 178.2 | 300.3 |
| Louisville | 146.2 | 187.1 | 320.3 |
| Memphis | 136.4 | 176.2 | 303.4 |
| Milwaukee | 136.9 | 188.2 | 304.8 |
| Minn.-St. Paul | 138.2 | 182.2 | 300.4 |
| Oklahoma City | 131.7 | 167.1 | 299.9 |
| Omaha | 132.9 | 178.2 | 309.9 |
| St. Louis | 139.2 | 175.2 | 289.3 |
| Tulsa | 134.8 | 170.2 | 297.2 |
| Wichita | 130.8 | 174.2 | 296.9 |
| PAD II avg | 137.7 | 182.9 | 306.2 |
| Albuquerque | 148.7 | 185.1 | 305.9 |
| Birmingham | 143.8 | 183.1 | 312.3 |
| Dallas-Fort Worth | 141.8 | 180.2 | 305.9 |
| Houston | 137.7 | 176.1 | 306.3 |
| Little Rock | 147.4 | 187.6 | 307.9 |
| New Orleans | 145.2 | 183.6 | 306.4 |
| San Antonio | 143.6 | 182.0 | 300.5 |
| PAD III avg | 144.0 | 182.5 | 306.5 |
| Cheyenne | 140.8 | 173.2 | 289.0 |
| Denver | 146.3 | 186.7 | 299.9 |
| Salt Lake City | 145.3 | 188.2 | 303.7 |
| PAD IV avg | 144.1 | 182.7 | 297.5 |
| Los Angeles | 147.7 | 214.8 | 334.8 |
| Phoenix | 161.9 | 199.3 | 297.7 |
| Portland | 180.9 | 224.3 | 328.8 |
| San Diego | 163.2 | 230.3 | 345.1 |
| San Francisco | 168.2 | 235.3 | 361.5 |
| Seattle | 168.3 | 224.2 | 338.5 |
| PAD V avg | 165.1 | 221.4 | 334.4 |
| **Week's avg.** | **145.5** | **191.1** | **312.4** |
| **Feb. avg.** | **144.0** | **189.6** | **303.1** |
| **Jan. avg.** | **131.5** | **177.1** | **304.5** |
| **2009 to date** | **137.7** | **183.3** | — |
| **2008 to date** | **260.3** | **303.9** | — |

*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

| | 2-20-09 ¢/gal | | 2-20-09 ¢/gal |
|---|---|---|---|
| **Spot market product prices** | | | |
| Motor gasoline (Conventional-regular) | | Heating oil No. 2 | |
| New York Harbor | 110.23 | New York Harbor | 119.24 |
| Gulf Coast | 107.31 | Gulf Coast | 115.11 |
| Los Angeles | 119.35 | Gas oil | |
| Amsterdam-Rotterdam-Antwerp (ARA) | 101.27 | ARA | 117.45 |
| Singapore | 130.71 | Singapore | 108.57 |
| Motor gasoline (Reformulated-regular) | | Residual fuel oil | |
| New York Harbor | 107.10 | New York Harbor | 85.64 |
| Gulf Coast | 106.60 | Gulf Coast | 93.38 |
| Los Angeles | 125.10 | Los Angeles | 113.07 |
| | | ARA | 80.24 |
| | | Singapore | 93.35 |

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

## BAKER HUGHES RIG COUNT

| | 2-27-09 | 2-29-08 |
|---|---|---|
| Alabama | 2 | 3 |
| Alaska | 11 | 8 |
| Arkansas | 50 | 39 |
| California | 24 | 35 |
| Land | 23 | 34 |
| Offshore | 1 | 1 |
| Colorado | 62 | 110 |
| Florida | 0 | 0 |
| Illinois | 1 | 0 |
| Indiana | 1 | 1 |
| Kansas | 16 | 9 |
| Kentucky | 11 | 11 |
| Louisiana | 144 | 144 |
| N. Land | 71 | 45 |
| S. Inland waters | 5 | 19 |
| S. Land | 23 | 29 |
| Offshore | 45 | 51 |
| Maryland | 0 | 0 |
| Michigan | 0 | 1 |
| Mississippi | 12 | 10 |
| Montana | 3 | 10 |
| Nebraska | 0 | 1 |
| New Mexico | 39 | 68 |
| New York | 3 | 7 |
| North Dakota | 58 | 57 |
| Ohio | 8 | 12 |
| Oklahoma | 120 | 200 |
| Pennsylvania | 25 | 19 |
| South Dakota | 0 | 1 |
| Texas | 538 | 859 |
| Offshore | 5 | 7 |
| Inland waters | 0 | 4 |
| Dist. 1 | 10 | 22 |
| Dist. 2 | 18 | 33 |
| Dist. 3 | 46 | 57 |
| Dist. 4 | 46 | 94 |
| Dist. 5 | 115 | 177 |
| Dist. 6 | 94 | 119 |
| Dist. 7B | 16 | 31 |
| Dist. 7C | 39 | 47 |
| Dist. 8 | 64 | 127 |
| Dist. 8A | 19 | 18 |
| Dist. 9 | 20 | 45 |
| Dist. 10 | 46 | 78 |
| Utah | 26 | 44 |
| West Virginia | 25 | 28 |
| Wyoming | 49 | 72 |
| Others—NV-5; TN-4; VA-4; WA-2 | 15 | 14 |
| **Total US** | **1,243** | **1,763** |
| **Total Canada** | **394** | **632** |
| **Grand total** | **1,637** | **2,395** |
| US Oil rigs | 260 | 337 |
| US Gas rigs | 970 | 1,418 |
| Total US offshore | 52 | 59 |
| **Total US cum. avg. YTD** | **1,623** | **1,758** |

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

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

## SMITH RIG COUNT

| Proposed depth, ft | Rig count | 2-27-09 Percent footage* | Rig count | 2-29-08 Percent footage* |
|---|---|---|---|---|
| 0-2,500 | 46 | — | 66 | 4.5 |
| 2,501-5,000 | 66 | 51.5 | 107 | 52.3 |
| 5,001-7,500 | 173 | 20.2 | 199 | 22.1 |
| 7,501-10,000 | 261 | 3.0 | 458 | 3.4 |
| 10,001-12,500 | 247 | 2.8 | 421 | 4.7 |
| 12,501-15,000 | 240 | 0.4 | 313 | 0.3 |
| 15,001-17,500 | 134 | — | 98 | — |
| 17,501-20,000 | 73 | — | 76 | — |
| 20,001-over | 41 | — | 38 | — |
| **Total** | **1,281** | **6.6** | **1,776** | **7.8** |
| INLAND | 16 | | 33 | |
| LAND | 1,215 | | 1,692 | |
| OFFSHORE | 50 | | 51 | |

*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]2-27-09 | [2]2-29-08 |
|---|---|---|
| | 1,000 b/d | |
| (Crude oil and lease condensate) | | |
| Alabama | 21 | 22 |
| Alaska | 727 | 706 |
| California | 658 | 664 |
| Colorado | 63 | 67 |
| Florida | 6 | 6 |
| Illinois | 28 | 24 |
| Kansas | 105 | 105 |
| Louisiana | 1,364 | 1,274 |
| Michigan | 15 | 16 |
| Mississippi | 60 | 58 |
| Montana | 91 | 86 |
| New Mexico | 164 | 161 |
| North Dakota | 188 | 138 |
| Oklahoma | 176 | 171 |
| Texas | 1,349 | 1,332 |
| Utah | 58 | 56 |
| Wyoming | 147 | 143 |
| All others | 69 | 70 |
| **Total** | **5,289** | **5,099** |

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

## US CRUDE PRICES

| | 2-27-09 $/bbl* |
|---|---|
| Alaska-North Slope 27° | 33.47 |
| South Louisiana Sweet | 44.50 |
| California-Kern River 13° | 38.70 |
| Lost Hills 30° | 48.15 |
| Wyoming Sweet | 30.76 |
| East Texas Sweet | 40.75 |
| West Texas Sour 34° | 33.50 |
| West Texas Intermediate | 41.25 |
| Oklahoma Sweet | 41.25 |
| Texas Upper Gulf Coast | 35.25 |
| Michigan Sour | 33.25 |
| Kansas Common | 40.25 |
| North Dakota Sweet | 32.75 |

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

## WORLD CRUDE PRICES

| $/bbl[1] | 2-20-09 |
|---|---|
| United Kingdom-Brent 38° | 42.29 |
| Russia-Urals 32° | 41.63 |
| Saudi Light 34° | 37.22 |
| Dubai Fateh 32° | 42.21 |
| Algeria Saharan 44° | 43.19 |
| Nigeria-Bonny Light 37° | 44.96 |
| Indonesia-Minas 34° | 44.33 |
| Venezuela-Tia Juana Light 31° | 37.21 |
| Mexico-Isthmus 33° | 37.10 |
| OPEC basket | 40.96 |
| Total OPEC[2] | 39.86 |
| Total non-OPEC[2] | 39.89 |
| Total world[2] | 39.87 |
| US imports[3] | 37.20 |

[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]

| | 2-20-09 | 2-13-09 | 2-20-08 | Change, % |
|---|---|---|---|---|
| | bcf | | | |
| Producing region | 723 | 737 | 581 | **24.4** |
| Consuming region east | 876 | 947 | 881 | **–0.6** |
| Consuming region west | 296 | 312 | 201 | **47.3** |
| **Total US** | **1,895** | **1,996** | **1,663** | **14.0** |
| | **Dec. 08** | **Dec. 07** | **Change, %** | |
| **Total US[2]** | **2,840** | **2,879** | **–1.4** | |

[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

| | Dec. 2008 | Nov. 2008 | 12 month average production 2008 | 12 month average production 2007 | Change vs. previous year Volume | Change vs. previous year % | Dec. 2008 | Nov. 2008 | Cum. 2008 |
|---|---|---|---|---|---|---|---|---|---|
| | Crude, 1,000 b/d | | | | | | Gas, bcf | | |
| Argentina | 608 | 630 | 609 | 625 | –17 | –2.7 | 117.5 | 116.6 | 1,490.99 |
| Bolivia | 40 | 40 | 40 | 44 | –3 | –7.7 | 42.0 | 41.0 | 503.60 |
| Brazil | 1,850 | 1,807 | 1,813 | 1,748 | 65 | 3.7 | 35.0 | 35.0 | 441.00 |
| Canada | 2,665 | 2,691 | 2,589 | 2,619 | –30 | –1.1 | 498.6 | 447.6 | 5,602.16 |
| Colombia | 590 | 600 | 580 | 531 | 49 | 9.1 | 22.0 | 22.0 | 270.00 |
| Ecuador | 490 | 480 | 498 | 499 | –2 | –0.3 | 1.0 | 1.0 | 12.00 |
| Mexico | 2,717 | 2,711 | 2,799 | 3,083 | –284 | –9.2 | 228.1 | 217.2 | 2,532.37 |
| Peru | 108 | 109 | 82 | 76 | 6 | 7.6 | 10.4 | 10.6 | 118.10 |
| Trinidad | 110 | 115 | 113 | 120 | –7 | –5.8 | 115.0 | 113.0 | 1,379.72 |
| United States | 4,989 | 4,938 | 4,943 | 5,065 | –121 | –2.4 | 1,864.0 | 1,802.0 | 21,453.00 |
| Venezuela[1] | 2,290 | 2,350 | 2,352 | 2,398 | –46 | –1.9 | 72.0 | 72.0 | 888.00 |
| Other Latin America | 83 | 83 | 83 | 83 | — | 0.1 | 5.5 | 5.3 | 65.58 |
| **Western Hemisphere** | **16,540** | **16,554** | **16,499** | **16,889** | **–390** | **–2.3** | **3,011.2** | **2,883.3** | **34,756.51** |
| Austria | 17 | 18 | 17 | 17 | — | –1.1 | 4.9 | 4.8 | 53.85 |
| Denmark | 285 | 292 | 287 | 312 | –25 | –8.0 | 30.6 | 28.2 | 330.15 |
| France | 19 | 18 | 20 | 20 | — | 0.7 | 3.1 | 2.8 | 32.94 |
| Germany | 59 | 58 | 60 | 67 | –7 | –10.8 | 48.6 | 46.0 | 547.67 |
| Italy | 87 | 92 | 100 | 108 | –8 | –7.7 | 25.0 | 24.0 | 302.00 |
| Netherlands | 29 | 29 | 34 | 40 | –7 | –16.4 | 350.0 | 300.0 | 3,030.00 |
| Norway | 2,287 | 2,276 | 2,180 | 2,271 | –91 | –4.0 | 352.4 | 332.0 | 3,503.85 |
| Turkey | 38 | 42 | 41 | 41 | — | 0.5 | — | — | — |
| United Kingdom | 1,485 | 1,415 | 1,416 | 1,524 | –109 | –7.1 | 235.3 | 226.0 | 2,594.13 |
| Other Western Europe | 3 | 3 | 4 | 4 | –1 | –15.2 | 2.2 | 2.2 | 20.39 |
| **Western Europe** | **4,309** | **4,243** | **4,157** | **4,404** | **–248** | **–5.6** | **1,052.0** | **965.9** | **10,414.96** |
| Azerbaijan | 800 | 750 | 891 | 827 | 64 | 7.8 | 35.0 | 31.0 | 388.00 |
| Croatia | 14 | 15 | 15 | 16 | –1 | –6.3 | 5.7 | 5.6 | 67.02 |
| Hungary | 14 | 14 | 14 | 16 | –1 | –8.8 | 7.8 | 7.8 | 90.02 |
| Kazakhstan | 1,500 | 1,450 | 1,398 | 1,088 | 310 | 28.5 | 100.0 | 100.0 | 1,018.00 |
| Romania | 90 | 90 | 93 | 98 | –5 | –5.2 | 19.0 | 18.0 | 215.00 |
| Russia | 9,660 | 9,760 | 9,748 | 9,883 | –135 | –1.4 | 2,000.0 | 1,900.0 | 22,750.00 |
| Other FSU | 450 | 400 | 408 | 461 | –53 | –11.4 | 550.0 | 550.0 | 5,740.00 |
| Other Eastern Europe | 46 | 46 | 48 | 48 | — | –1.0 | 20.9 | 19.8 | 210.21 |
| **Eastern Europe and FSU** | **12,573** | **12,525** | **12,614** | **12,435** | **179** | **1.4** | **2,738.4** | **2,632.2** | **30,478.25** |
| Algeria[1] | 1,320 | 1,350 | 1,373 | 1,358 | 14 | 1.0 | 275.0 | 270.0 | 3,300.00 |
| Angola[1] | 1,830 | 1,888 | 1,894 | 1,697 | 197 | 11.6 | 5.0 | 5.0 | 59.10 |
| Cameroon | 80 | 80 | 84 | 85 | –1 | –1.3 | — | — | — |
| Congo (former Zaire) | 25 | 25 | 25 | 25 | — | — | — | — | — |
| Congo (Brazzaville) | 240 | 240 | 240 | 240 | — | — | — | — | — |
| Egypt | 700 | 700 | 679 | 645 | 34 | 5.3 | 135.0 | 130.0 | 1,610.00 |
| Equatorial Guinea | 320 | 320 | 320 | 320 | — | — | 0.1 | 0.1 | 0.72 |
| Gabon | 240 | 240 | 235 | 230 | 5 | 2.2 | 0.3 | 0.3 | 3.67 |
| Libya[1] | 1,720 | 1,710 | 1,724 | 1,708 | 16 | 0.9 | 38.0 | 35.0 | 415.00 |
| Nigeria[1] | 1,910 | 1,900 | 1,944 | 2,161 | –217 | –10.0 | 82.0 | 78.0 | 957.00 |
| Sudan | 500 | 500 | 490 | 473 | 18 | 3.7 | — | — | — |
| Tunisia | 88 | 88 | 85 | 95 | –9 | –9.9 | 8.3 | 8.0 | 78.87 |
| Other Africa | 221 | 221 | 221 | 222 | — | –0.1 | 9.1 | 8.7 | 106.90 |
| **Africa** | **9,194** | **9,262** | **9,315** | **9,258** | **57** | **0.6** | **552.8** | **535.1** | **6,531.26** |
| Bahrain | 170 | 170 | 169 | 172 | –2 | –1.3 | 34.0 | 33.0 | 329.59 |
| Iran[1] | 3,880 | 3,760 | 3,907 | 3,933 | –26 | –0.7 | 300.0 | 280.0 | 3,515.00 |
| Iraq[1] | 2,410 | 2,430 | 2,382 | 2,093 | 289 | 13.8 | 22.0 | 22.0 | 241.20 |
| Kuwait[1,2] | 2,520 | 2,585 | 2,602 | 2,444 | 158 | 6.5 | 42.0 | 42.0 | 501.00 |
| Oman | 700 | 710 | 718 | 710 | 8 | 1.1 | 58.0 | 58.0 | 700.00 |
| Qatar[1] | 800 | 820 | 848 | 801 | 48 | 5.9 | 180.0 | 180.0 | 2,170.00 |
| Saudi Arabia[1,2] | 8,260 | 8,665 | 9,046 | 8,625 | 422 | 4.9 | 200.0 | 200.0 | 2,570.00 |
| Syria | 400 | 400 | 389 | 389 | — | — | 18.0 | 17.0 | 211.00 |
| United Arab Emirates[1] | 2,450 | 2,300 | 2,586 | 2,532 | 54 | 2.1 | 130.0 | 120.0 | 1,565.00 |
| Yemen | 290 | 300 | 306 | 338 | –32 | –9.4 | — | — | — |
| Other Middle East | — | — | — | — | — | — | 10.5 | 10.0 | 128.68 |
| **Middle East** | **21,880** | **22,140** | **22,953** | **22,035** | **918** | **4.2** | **994.5** | **962.0** | **11,931.47** |
| Australia | 499 | 511 | 459 | 451 | 8 | 1.7 | 121.9 | 122.6 | 1,350.80 |
| Brunei | 160 | 160 | 160 | 179 | –19 | –10.4 | 34.0 | 33.0 | 408.20 |
| China | 3,709 | 3,870 | 3,803 | 3,739 | 63 | 1.7 | 234.8 | 241.3 | 2,828.70 |
| India | 690 | 681 | 677 | 687 | –10 | –1.5 | 87.2 | 85.5 | 1,028.83 |
| Indonesia[1] | 840 | 850 | 857 | 839 | 18 | 2.2 | 220.0 | 215.0 | 2,730.00 |
| Japan | 18 | 17 | 17 | 17 | — | 0.7 | 12.0 | 11.1 | 128.95 |
| Malaysia | 740 | 760 | 757 | 759 | –3 | –0.3 | 140.0 | 140.0 | 1,725.00 |
| New Zealand | 37 | 44 | 54 | 37 | 17 | 45.5 | 10.0 | 11.5 | 147.40 |
| Pakistan | 68 | 66 | 66 | 68 | –2 | –3.0 | 124.3 | 120.1 | 1,463.00 |
| Papua New Guinea | 40 | 40 | 41 | 47 | –5 | –11.6 | 1.0 | 0.9 | 11.50 |
| Thailand | 228 | 227 | 228 | 212 | 16 | 7.5 | 25.0 | 32.0 | 496.00 |
| Vietnam | 250 | 250 | 273 | 310 | –37 | –11.8 | 15.0 | 14.0 | 178.50 |
| Other Asia-Pacific | 35 | 35 | 39 | 34 | 5 | 14.4 | 96.5 | 94.5 | 1,168.06 |
| **Asia-Pacific** | **7,313** | **7,510** | **7,432** | **7,380** | **51** | **0.7** | **1,121.7** | **1,121.4** | **13,664.95** |
| **TOTAL WORLD** | **71,810** | **72,234** | **72,969** | **72,403** | **567** | **0.8** | **9,470.5** | **9,100.0** | **107,777.40** |
| OPEC | 30,720 | 31,088 | 32,012 | 30,588 | 1,425 | 4.7 | 1,567.0 | 1,520.0 | 18,923.30 |
| North Sea | 4,077 | 4,007 | 3,901 | 4,126 | –225 | –5.4 | 723.1 | 676.0 | 7,333.70 |

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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## Obama's budget isn't just change; it's derangement

*Change is nearly always good. The same can't be said for derangement. President Barack Obama, who ran for office as the high priest of change, has crossed this line.*

*He must believe the wildest energy delusion of his party's leftmost fringe: that the US can subsidize its way off oil and gas and run the economy on alternative energy forms.*

*It can't do so anytime soon. But it can go broke trying.*

*The budget Obama sent Congress on Feb. 26 would demolish capital formation by the US oil and gas industry.*

*It proposes to raise $31.5 billion over 11 years by eliminating "oil and gas company preferences" in taxation (OGJ Online, Feb. 26, 2009).*

*It would levy an excise tax on Gulf of Mexico production.*

*It would repeal the expensing of intangible drilling costs by producers and the manufacturing tax deduction for oil and gas companies.*

*It would increase the geological and geophysical amortization period for independent producers to 7 years and repeal percentage depletion for oil and gas.*

*It also would repeal the enhanced oil recovery credit, marginal well tax credit, deduction for tertiary injectants, and passive exception for working interests in oil and gas properties.*

*For an additional $17.2 billion, the budget would revive the "Superfund" tax to pay for cleanup of abandoned hazardous-waste sites.*

*Many of these and other proposals, such as use-it-or-lose-it lease stipulations and increased fees for operating permits, resurrect bad ideas considered but rejected by Congress.*

*Revenue projections associated with them are illusory, obviously assuming levels of oil and gas activity that would be impossible if the changes were enacted.*

*This nest of economic snakes isn't the usual, sophomoric slap at "Big Oil." The imperiled drilling preferences are crucial to small operators. Percentage depletion, in fact, is available only to independent producers and restricted for all but the smallest of them. This is a broadside attack on US oil and gas in general. It makes Obama's talk about cutting dependency on foreign oil and reviving the economy laughable but sobering.*

*The president and the country he leads need a quick dose of reality.*

*(Online Feb. 27, 2009; author's e-mail: bobt@ogjonline.com)*

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

## Crude market tries to stabilize

The price of gasoline climbed and crude hit a 1-month high in a 3-day rally before dropping slightly Feb. 27 on the New York futures market.

The April contract for US light, sweet crudes climbed to $45.22/bbl Feb. 26 on the New York Mercantile Exchange after the Energy Information Administration reported an unexpected large drop in US gasoline inventories, down 3.4 million bbl to 215.3 million bbl in the week ended Feb. 20. The same contract slipped to $44.76/bbl in the next session, the last for that short month, as the Department of Commerce reported the US gross domestic product fell 6.2% during the last quarter of 2008. That was the largest decline in GDP since the first quarter of 1982. Economists were expecting a decline of 3.8%.

"Yes, unemployment is high, but the lower gasoline prices seem to finally have an impact, and with jet [fuel] demand down 15.4% (237,000 b/d), it does seem that Americans are back to driving rather than flying," said Olivier Jakob at Petromatrix, Zug, Switzerland. He said 2008 was the year of distillate vs. gasoline, while 2009 seems to be gasoline vs. distillate. "In that regard," Jakob said, "we need to keep in mind that refineries are currently on maintenance and that it is not unusual to have all sort of glitches when the units are brought on line."

In New Orleans, Pritchard Capital Partners LLC analysts said, "If gasoline price response continues, gasoline demand may push utilization up and continue to support crude prices and even pull some crude out of storage and reduce contango spreads seen across curve." EIA data indicated US gasoline consumption in the 4 weeks through Feb. 20 was up 1.7% from year-ago levels.

Paul Horsnell at Barclays Capital Inc., London, noted US demand for gasoline has been relatively robust in the face of the economic cycle compared with diesel and jet fuel demand, which have been far more negatively affected. "Gasoline inventories are much lower year-over-year and demand is improving, while distillate inventories are much higher year-over-year and demand is not improving," he said.

However, Larry Goldstein, a director at Energy Policy Research Foundation (EPRINC), said EIA is comparing the latest 4 weeks of preliminary data with final revised data from a year ago and getting the wrong figures. "The correct comparison is [preliminary] weekly against [preliminary] weekly," Goldstein told OGJ. "That will show a measurable improvement in the decline rate but still a modest decline from negative 3.5% several months ago to about 0.5% decline over the last 4 weeks—a major improvement but still modestly negative," he said.

**OPEC is 'adamant'**

Members of the Organization of Petroleum Exporting Countries "remain adamant about compliance of supply cuts and will likely cut production quotas further next month," said analysts in the Houston office of Raymond James & Associates Inc. However, they said, "The biggest driver remains the economic uncertainty and its effect on demand."

Raymond James reduced their oil price forecasts to $43/bbl from $60/bbl for 2009 and to $65/bbl from $80.bbl in 2010 "due to the severity of the global economic meltdown and bloated inventory levels at Cushing, [Okla.]," key delivery point for US crude. They said, "Non-OPEC supply has peaked, while demand will eventually recover. If such a recovery occurs in 2010, our forecast will move much higher."

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said, "Additional OPEC cuts and more convincing signs of an economic upturn are required to stabilize oil prices. Since we expect the G7 [industrialized nations: Canada, France, Germany, Italy, Japan, UK, and US] will require additional fiscal stimulus packages to support growth, we remain skeptical of near-term crude oil price rallies."

But at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, analysts said, "There is a sense that the [oil] market might be starting to tighten."

At Barclays Capital, Horsnell noted the recent sharp reduction of US crude imports. "The data also show the first week of imports below 5 million b/d into the Gulf Coast since the height of the hurricane disruption. The figures may well show occasional blips as the remaining floating storage dissipates and partially enters the data, and trends in time structure and tanker rates suggest that that process is likely to gain pace," he said. However, Horsnell said, "Despite the scope for temporary boosts to imports while the amount of floating storage is reduced, we would still expect to see a fairly prolonged period of year-over-year crude oil import compression to set in."

(Online Mar. 2, 2009; author's e-mail: samf@ogjonline.com)

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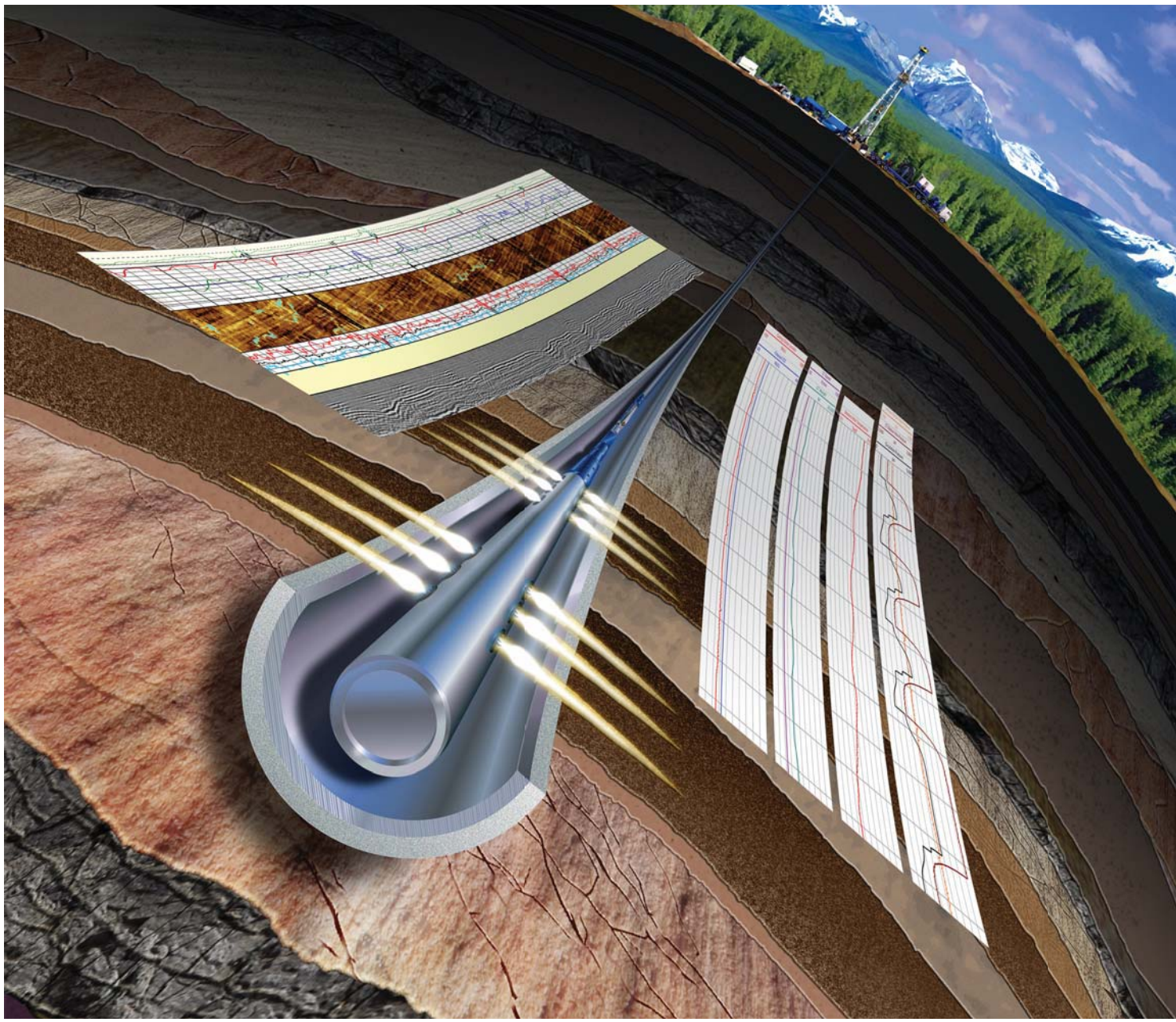

# Advanced Coiled Tubing Solutions

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An asterisk (*) is used throughout this document to denote a mark of Schlumberger.

"When you know exactly what's happening downhole, you can adjust job parameters in real time based on downhole measurements. The Schlumberger lineup of ACTive coiled tubing services that is now available applies to a variety of services—from perforating using accurate and defined BHP, to running inflatable packers, monitoring downhole temperature and pressure, and increasing zonal coverage for matrix stimulation, and even for formation evaluation. For the first time, operators can manage downhole treatments with positive feedback and make a difference to the results with complete confidence when it matters the most—while the operation is still in progress."

**Sherif Foda**
*vice president,*
*coiled tubing services*


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# A SECRET BEGINNING

The first application of coiled tubing (CT) technology was not for oil wells, but for a plan to lay emergency pipelines across the English Channel during World War II. Allied engineers made coiled tubing from 40-foot lengths of 3-inch pipe and spooled it around huge floating drums that could be towed behind ships. In 1944, some of the 23 secret pipelines they laid delivered Allied fuel for the Normandy invasion.

The Allies made their coiled tubing by welding joints of pipe end to end. The idea is simple enough, but making coiled tubing that is safe and dependable is much more complicated. The low-grade steel used in the early days couldn't take the tensile stress of heavy loads, and the many welds required to produce continuous spools of pipe frequently leaked or broke.

Steady improvements in manufacturing and metallurgy through the 1970s and 80s greatly improved the reliability of coiled tubing. In 1990, the first string of 2-inch coiled tubing was milled for a permanent well completion, and suppliers soon began offering coiled tubing up to 4-½ inches outside diameter.

Service companies quickly developed new CT applications. In well workovers, coiled tubing became the tool of choice for removing cement plugs and scale. When customers said they wanted to drill more slimhole wells for exploration and production, coiled tubing was a natural choice.

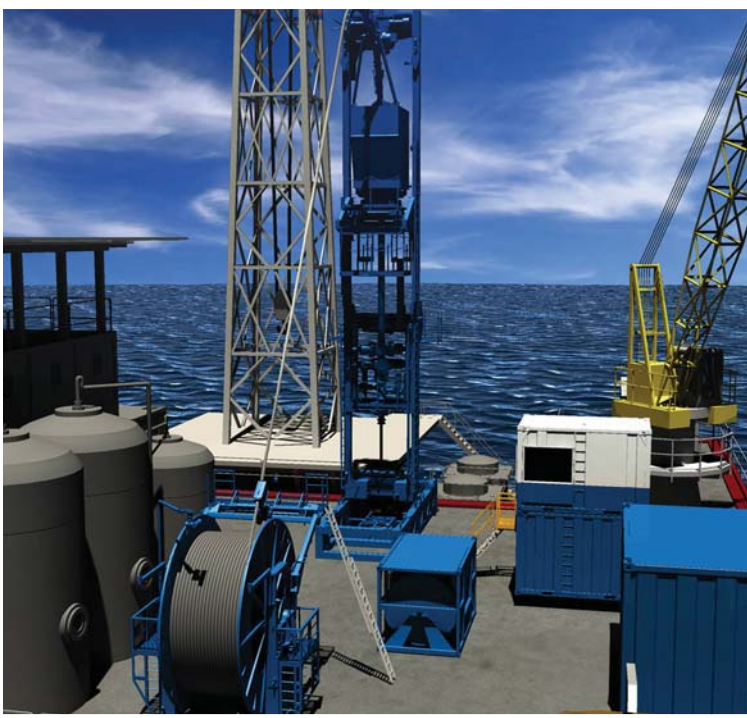

The big advantage of coiled tubing, of course, is that tripping in and out of a well is continuous. That is not only faster than making up joints of tubing, it requires fewer people on the rig floor and makes the whole operation safer.

Coiled tubing units can also deploy downhole tools that cannot be run on conventional wirelines. The two main benefits, however, are that with coiled tubing, operators can pump fluids through the coil, and they can push tools into the well rather than lowering them down on a wireline. Depending on the size of the spool and diameter of the pipe (1 inch to 4.5 inches), coiled tubing is available in lengths in excess of 30,000 feet. Once reserved for niche services only, coiled tubing is now an essential well intervention tool.

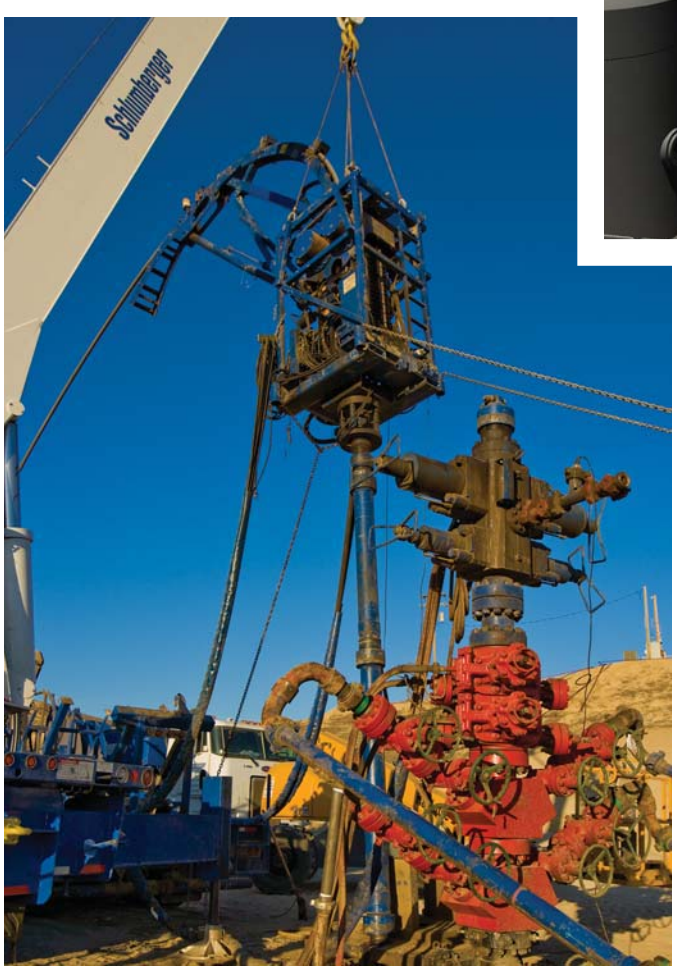
For drilling and workovers, CT rigs are much smaller and lighter than the rigs that use conventional tubing, and they need less room at the drill site. Some oil and gas operators now use CT routinely to drill shallow wells. In unconsolidated sands, coiled tubing rigs can drill at rates up to 1,300 fph, compared 400 fph for conventional rigs. Current technology allows CT drilling beyond 7,000 feet, and some heavy-duty units are targeting depths of 10,000 feet.

Coiled tubing moved offshore in the mid-1980s, where CT engineers had to overcome much greater challenges than they faced on land. Even though CT is lighter than rigid-tubing rigs, the equipment was still too bulky for most offshore platforms, and if the tubing was deployed from a nearby vessel, operators had to deal with the vertical and lateral movement caused by the sea. Today, thanks to CT SEAS* Safer, Efficient, Automated Solutions other advanced Schlumberger technology, coiled tubing offshore is an increasingly valuable option.

# The basic CT rig



The main components, other than the spool of coiled tubing itself, are the injector head, the stripper and the blowout preventers. Of these, the injector head is the driver, because it is the machine that pushes and pulls coiled tubing in and out of the well. The device includes a curved gooseneck beam that guides the coiled tubing from its spool into the top of the injector head.




Pipe passing through the injector head straightens before it enters the wellbore. A stripper, set below the injector head, contains the packing that seals the outside diameter of the tubing and isolates pressure from the well.

Blowout preventers, located below the stripper, are emergency devices that can either cut the coiled tubing and seal the wellbore, or if necessary, seal the casing or riser.

The tool string at the bottom of the coil is called the bottomhole assembly. One advantage of coiled tubing is that it can run a much wider range of tools and perform many more downhole jobs than can be done with conventional wirelines.

# Applications

Coiled tubing can perform almost any downhole job. In depleted gas wells, CT has even been installed as production tubing and can be run inside a well's conventional tubing string. While many production engineers think of CT as an alternative to wireline service—and it is—the technology is much broader than that.

**Well cleanouts:** Nearly half of all coiled tubing jobs are done to get a well back in production by circulating fluids and debris from the wellbore. Through an innovative mix of hardware, software, fluid cleanout systems and monitoring, production engineers worldwide are using Schlumberger coiled tubing applications to reduce the cost and risk of cleanout operations and quickly return their wells to production.

The difficulty of any cleanout job depends largely on the geometry of the well, properties of the cleanout fluid, flow rate, downhole pressures, the nature of the solids that must be removed, and how deep they are in the well.

Cleanouts are relatively easy for shallow wells with simple geometries. When deviation angles reach above 40 degrees, however, almost any wellbore can be hard to clean. Often, several techniques are combined to clean one well. Schlumberger began integrating its wellbore cleanout and optimization systems in 2002 and continues to improve this robust lineup.

Jet Blaster* jetting scale removal service is a CT-conveyed through-tubing tool that uses a rotating head and high pressure fluids to remove scale, including hard scale (strontium and iron sulfide), from wellbores in one trip. It is a fast and cost-effective alternative to nozzle systems, positive-displacement motors, impact hammers and other techniques on the market.

PowerCLEAN* engineered fill removal service is a CT service that efficiently lifts sand, silt, wax, scale and other debris from the wellbore. The system's innovative software, coupled with engineered nozzle and fluids, optimizes the job by evaluating the flow rate, circulating pressure, bottomhole pressure and other variables before taking each bite of fill.

**Workovers:** In recent years, coiled tubing has become an efficient, cost-effective solution for open-hole milling, fracturing and many other workover jobs.

CoilTOOLS* is a one-stop source for the latest downhole CT tools. The portfolio includes standard bottom-hole assemblies such as motor heads, connectors, check-valve, disconnect assemblies, knuckle joints, fixed and hydraulic centralizers, fixed and rotary wash tools, nipple locators, gauge carriers and the entire suite of downhole valves.

Discovery MLT* multilateral tool is a cost-effective reentry system for maximizing the performance of multilateral wells. The downhole tool sends a pressure signal to confirm that it has reached the correct lateral. The tool's orientation adjusts from the surface and provides real-time feedback, which greatly increases the chance of a successful reentry on the first try to Level 1 and

2 multilateral wells. The Discovery MLT software displays several essential parameters, such as the tool's orientation relative to the lateral window. The application also monitors previous indexes and guides the operator through subsequent indexing cycles to provide accurate, real-time information.

Coiled tubing is often used to pump fluids to specific sections of a well, and Schlumberger has a suite of CT tools that make the job go easier. CoilFLATE* through-tubing inflatable packer designed for extreme conditions. CoilFLATE packer can isolate selected perforation intervals with pump-through capability, without the need for a workover rig. The system also allows operators to permanently abandon zones or temporarily isolate areas of the wellbore for testing.

CoilFRAC* stimulation through coiled tubing is a well stimulation service that incorporates unique bottomhole assemblies to selectively isolate zones of interest. CoilFRAC service can treat multiple zones in a single trip and stimulate zones that were bypassed during the original completion. Many operators are using this economical system to stimulate lower-producing zones that were too expensive to treat before.

CoilCAT* coiled tubing computer-aided treatment raises informed real-time decision making to a new level of confidence. The new CoilCAT well site service makes well interventions more efficient and reliable. CoilCAT service combines the Coiled Tubing Sensor Interface advanced data acquisition system with the Universal Tubing Integrity Monitor and software to efficiently merge design, execution and real-time evaluation capabilities in one package.

**Perforating:** Coiled tubing offers many advantages over other conveyance systems, particularly for highly deviated and horizontal wells. First is the strength and rigidity of the tubing, which can endure more tensile and compressive forces than wireline systems. Schlumberger routinely runs coiled tubing perforating strings in excess of 2,000 feet (600 meters) on Alaska's North Slope.


For live wells, CT perforating can run long gun strings and either drop them off or retrieve them without having to kill the well. The ability to continuously circulate through the tubing also makes it easy to spot-treat with fluids. Treating a carbonate interval with acid just before perforating, for example, creates cleaner perforations.

In depleted wells where there is not enough difference between the bottomhole pressure and pressure from the reservoir, nitrogen can be circulated to lighten the fluid column and increase the drawdown at the target zone.

# Fit-for-purpose solutions

**CT EXPRESS*** rapid-deployment coiled tubing service is designed for low- to medium-pressure, intermediate-depth land-based wells. The simple, reliable design can handle rough terrain and extreme weather conditions.

The unit consists of just two trucks and a crew of three. One truck holds the CT rig itself, and the second vehicle carries a combination nitrogen and liquid pump, plus electrical and hydraulic systems to run the entire unit. Since there are no hydraulic or electrical connections to be made on location, rig-ups are safer and more efficient than with other systems. During field tests, CT EXPRESS crews performed more than 200 jobs without a lost-time incident.

With CT EXPRESS service, rig-up and rig-down times are as short as 30 minutes. Coiled tubing rigs with similar capabilities typically require four trucks and a crew of five. CT EXPRESS service can be used on wellheads up to 20 feet high; the system can also be deployed onto the rig floor of land rigs if required.

**CT SEAS*** Safer, Efficient, Automated Solutions, is a fit-for-purpose offshore CT system that greatly improves the efficiency and safety of moving from one well to the next. Designed for harsh offshore conditions, the system incorporates the same proven process control and distributed architecture of the CT EXPRESS rapid-deployment coiled tubing unit for land-based operations.

Speed is a key feature. In some cases, well-to-well time is as little as four hours. The system's ergonomic design, smaller footprint and high degree of automation also make it less costly than other alternatives.

The CT SEAS system provides one central control point for the entire coiled tubing operation, as well as real-time data acquisition and data transfer to offsite locations. The versatile, space-saving design combines all the major coiled tubing components into modules that are easy to transport and assemble with zero discharge. Because several key processes have been automated, CT SEAS systems also require fewer operators than conventional CT units, which is a real advantage offshore.

CT SEAS systems have a flexibility that makes them readily adaptable for many offshore structures, including platforms, floaters and tension leg platforms. But even with a high degree of flexibility, they retain all the capabilities of conventional coiled tubing units.

This advanced system improves the overall safety of coiled tubing operations; with a proven 15 percent increase in operational efficiency, a substantial reduction in boat lifts, and 30 percent

fewer offshore personnel. The design of the equipment package features fewer mechanical connections, improved control room ergonomics, and faster well-to-well cycle times. Compared to earlier systems, CT SEAS systems can also run heavier coiled tubing at increased speeds.

**CT TCOMP*** advanced coiled tubing motion-compensation system is made specifically for deepwater use. It is the result of a two-year field study to identify the potential safety and efficiency that could be gained by improving the design and packaging of compensation equipment. The result is a total motion-compensation package for deepwater CT operations.

CT TCOMP system trims up to 16 hours from the average 87 hours it takes to rig up and rig down a standard deepwater CT system, and it is safer than other CT packages. It protects wellhead integrity during CT operations by limiting wellhead stresses, and by compensating for vertical and horizontal wellhead motion from inside or outside the derrick. And since the equipment rigs up quickly, it can be used on some spars (caisson vessels) and TLPs where conventional coiled tubing systems would be too expensive to use.

# ACTive services – a breakthrough in CT technology

In May 2008, Schlumberger introduced the ACTive family of coiled tubing services for onshore and offshore use. This innovative suite of downhole coiled tubing services provides continuous feedback that allows engineers—either at the well or in remote locations—to measure, interpret and act on downhole events in real time.

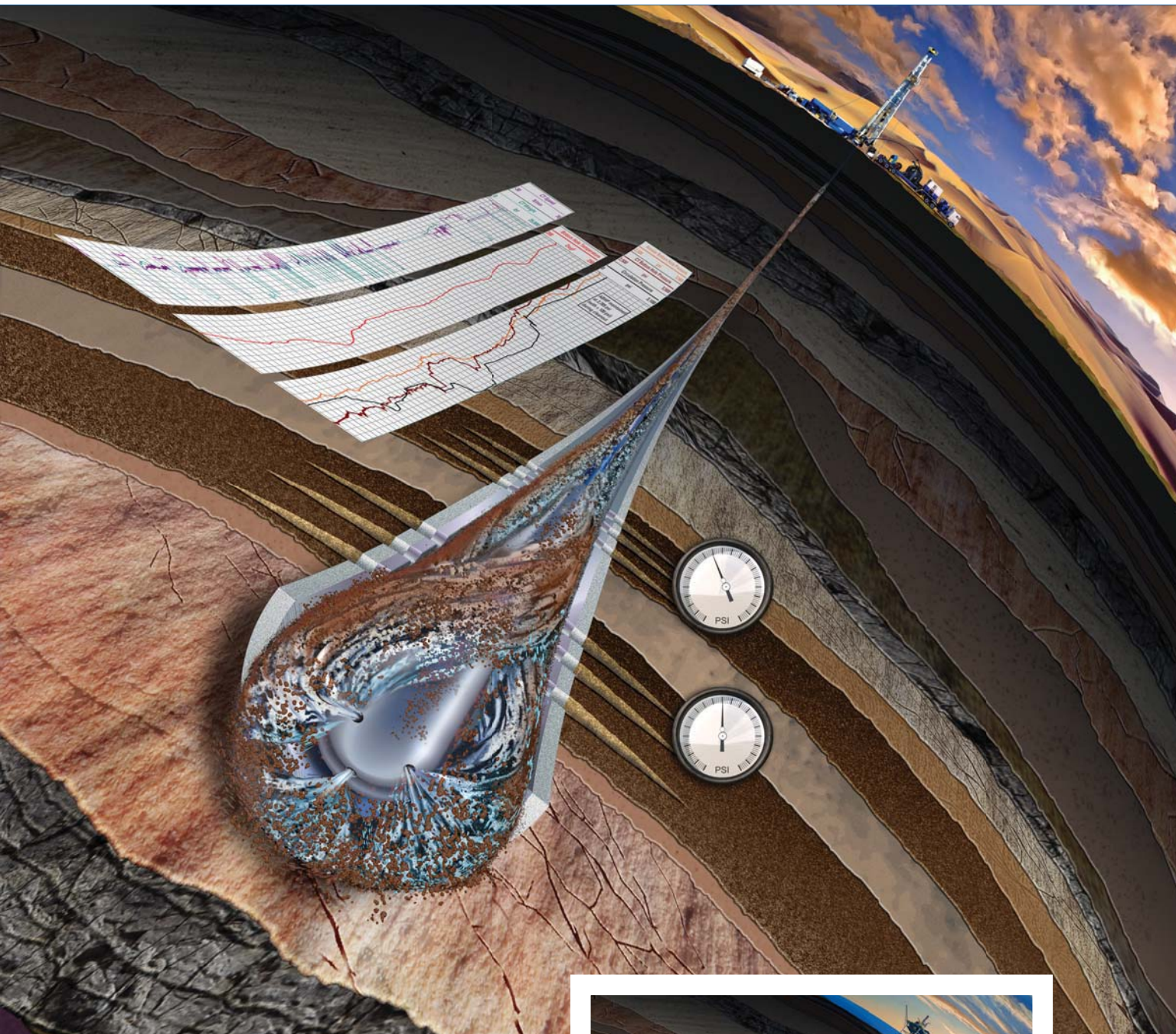
All previous systems relied on surface data and feedback from the well to determine what was happening downhole. Downhole pressure was estimated from pressure readings at the pump, the wellhead or both. Actual tool depth was inferred from the amount of coiled tubing in the hole, which is only accurate to within about 0.3 percent. When jobs required greater accuracy, crews might tag a known bottom or restriction, use tubing tail locators, or run mud-pulse telemetry logging tools. These techniques, however, are inaccurate, expensive and time consuming, and they can complicate the job.

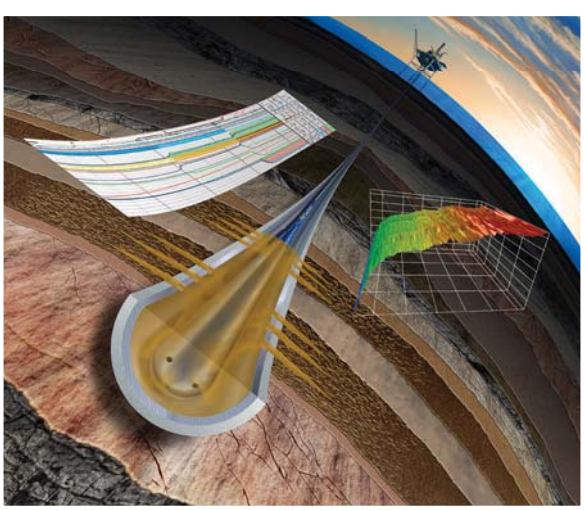
The ACTive difference is a rugged, high-bandwidth fiber optic cable inside its own nickel-chromium-based super-alloy steel carrier that is deployed inside the coiled tubing string. The fiber optic cable links bottomhole sensors with surface monitors and controls, allowing specialists to measure, interpret and act on downhole events as they occur.

The complete system includes a bottomhole assembly, fiber optic carrier, surface electronics and software that delivers internal and external pressure, temperature, casing collar locator depth correlation, and distributed temperature measurements that provide data back to surface in real time.

ACTive services can elevate the performance, efficiency and results of coiled tubing operations in various types of wells. Operators in western Canada, for example, need cost-effective ways to achieve maximum reservoir contact in their partially depleted carbonate reservoirs. Multilateral completions give them greater reservoir contact and the ability to reach isolated parts of the reservoir without excessive construction cost or complexity. Conventional coiled tubing services are often used to access and treat these multilateral wells, but without accurate depth information, it can be hard to confirm access in all the laterals. Operators not only have to correctly orient the bottomhole assembly to enter the lateral, they must first determine which lateral they are entering. For them, ACTive services represent a step change in CT capabilities.

ACTive services give operators the tools they need to diagnose and respond to changing conditions in real time. To take full advantage, Schlumberger fields a team of CT experts who stand ready to diagnose and respond, based on their knowledge, experience and the information they get from ACTive real-time downhole measurements.



As Schlumberger experts monitor the well, Decipher* dynamic evaluation software provides the information they need to cross-reference what they see downhole with surface and petrophysical data. For the first time, adjustments to job parameters are based on immediate feedback from the job in progress. Changes can be made decisively and with greater confidence than ever before.

# THE ACTIVE PORTFOLIO

There are six services in the ACTive portfolio. Each presents its own unique solution in the market by combining advanced, high data-rate telemetry, fiber optics and real-time downhole measurements with state-of-the-art interpretation software.

**ACTive Matrix** monitors the injection rates, downhole pressures and temperatures of matrix treatments to promote the penetration of fluids, enhance diversion and optimize treatment volumes. The service also aids in the design of subsequent treatments.

**ACTive Cleanout** is a fill-removal service that uses differential pressure readings to avoid formation damage and minimize the number of trips in and out of the well. It also reduces the total operating time by optimizing fluid volumes and penetration rates into the fill.

**ACTive Isolation** provides efficient, on-depth settings of isolation devices in a single run. It allows operators to insure the integrity of the seals by controlling both the inflation pressure and the differential pressure across the sealing elements. ACTive Isolation can also be used to accurately place fluids for temporary operations or to permanently isolate zones, all in one trip in the hole.

**ACTive Lift** improves the time and fluid efficiency of nitrogen lift jobs by continuously monitoring pressure in the wellbore. The result is a faster, more controlled restoration of production, without the risk of producing excessive sand and debris from the reservoir. This service also aids in the characterization of field performance and the evaluation of artificial lift programs.

**ACTive Perf** achieves accurate depth control in a single run and ensures full coverage of the target zone. Controlling the hydrostatic balance avoids damage to the formation, and prevents the invasion of formation fluids and sand into the wellbore. Verification that the perforating guns have been activated improves the safety and reliability of CT perforating jobs.

**ACTive Profiling** enhances all ACTive services with DTS profiling to provide a 3D temperature profile of the entire wellbore to monitor the placement of treatment fluids and production performance of the well. Temperature profiling also gives operators the ability to perform active point measurements and DTS spatial measurements on the same run.

# ACTive case studies

## Increased stimulation coverage of a multilateral gas well:

When an operator in Canada needed to increase the productivity of two openhole legs in an existing multilateral gas well, they turned to ACTive Matrix for a solution. The well, which is in a naturally fractured dolomite formation, was producing a high concentration of $H_2S$ and some $CO_2$.

Coiled tubing was run in the hole to obtain downhole measurements, which were used to stimulate the openhole legs. Acid treatments temporarily diverted and treated the sections of the open hole that would otherwise not have been stimulated. Pre- and post-treatment distributed temperature survey (DTS) data were used to optimize acid placement.

Using the more reliable real-time bottomhole pressure measurements, rather than surface pressure measurements, increased the accuracy and effectiveness of the stimulation treatments.

The initial acid treatment was confirmed. Injection points and other zones to be opened were identified. Thermal analysis results were used to generate a revised pump schedule that provided details of the appropriate diverter and acid stages, which allowed temporary diversion of the initially stimulated zones and better overall treatment of the multilateral leg.

A final DTS confirmed that the treatment successfully diverted the acid and stimulated all of the targeted zones.

## Accurate placement for a successful water shutoff:

Saudi Aramco chose ACTive Isolation when a 60 percent water cut caused one of its new horizontal wells to stop flowing. Most of the water was coming from the toe of the openhole completion. ACTive Isolation* provided a coiled tubing solution by allowing operators to deploy an inflatable packer through the production tubing and a cement plug to isolate the water-producing zone.

An initial CT run confirmed accessibility and revealed an accurate downhole temperature, which was needed to prepare the cement slurry. On the second run, the through-tubing inflatable packer was deployed to the depth of the oil/water interface. After confirming the depth, a ball was dropped in the coiled tubing to set the packer, and real-time measurements confirmed that the packer was properly located and set. A third run spotted cement on top of the inflatable packer.

Kill fluids were displaced with nitrogen, which was confirmed at the surface by monitoring the downhole pressure. With the well back in production, the water cut decreased by 50 percent and oil production increased by 1,000 barrels per day.

# ACTive case studies

## Effective sand cleanout:

Talisman Malaysia Ltd. (TML) drilled a water injector well in Malaysian waters of the South China Sea. After perforating the first zone, produced sand plugged the next perforating intervals. Despite efforts to clean the well using conventional CT methods, the planned intervals could not be reached. Injecting nitrogen to circulate fluids and flow the well only produced more sand.

The operator chose ACTive Cleanout and ACTive Perf to obtain real-time downhole measurements, which allowed better control of the cleanout and accurate placement of the perforating guns.

The existing sand in the wellbore was lifted out by keeping the bottomhole pressure balanced or slightly overbalanced using real-time bottomhole pressure data. The designed pumping schedule was then followed with continuous real-time monitoring of the pressure and temperature. Before continuing with the planned perforation run, an injectivity test ensured that the tunnels in the existing perforation interval were open.

Perforating resumed, with the guns successfully conveyed to the target depth and correlated against the base depth log. The real-time bottomhole pressure reading assured operators that they were maintaining the proper balance to keep additional sand from entering the wellbore. Using the real-time CCL correlations, the guns were positioned. The e-Fire* electronic firing head system was activated via nitrogen pulses through the coiled tubing. Both the bottomhole pressure and temperature increased after the guns were fired.

ACTive services allowed operators to effectively clean sand from the well, accurately place the perforating guns, fine-tune the bottomhole pressure and receive feedback at the surface once the guns were fired. As a result, the final water injectivity rate was 8,900 bbl/d at 700 psi surface pressure, which confirmed that sand was not reintroduced into the wellbore after the perforating operations were complete.

# ACTive case studies

## Identifying the causes of lost production:

When production dropped in a well that was completed using an openhole slotted liner in the Bunga Raya field, the operator, Talisman Malaysia Ltd. (TML), performed a chemical treatment to remove the emulsion and polymers left behind by the drilling fluid used to drill the well. Immediately after the treatment, production increased from 500 bbl/d to 2,000 bbl/d, but within five hours, it dropped dramatically and then stabilized at its pretreatment rate.

TML suspected that the emulsions and asphaltenes had formed in the wellbore during the shut-in time while rigging down. However, the operators did not have adequate information about the formation characteristics and the trajectory of the well. Without the data, they could not understand the cause of the production decline after treatment, where and how the emulsions and asphaltenes were forming, and how to dissolve them or prevent them from reforming.

TML asked Schlumberger to design a well cleanup plan, to obtain pressurized bottomhole samples, and to run a DTS. ACTive Profiling was chosen to provide a single-point temperature reading at the tool and to provide a temperature reading across the fiber optic cable used to deliver the DTS measurements.

The objectives were to check the conformance of the first DTS results and interpretation, to use the DTS data to select the location for collecting representative bottomhole hydrocarbon samples and to optimize the treatment interval.

The pressure survey and DTS data revealed minimum pressure support from the water injector, which, in turn, caused the gas cap to expand. Temperature dropped across the entire interval, but was lowest at the toe. The cooling effect and subsequent drop in liquid production was caused by gas coming from the heel and toe of the well as the gas cap expanded. The combination of gas rates with oil and water production was also creating a tight, viscous emulsion that further hindered the well's performance.

TML concluded that with this well, due to the horizontal openhole slotted-liner completion, the high gas production from the toe and heel could not be selectively shut off or controlled.

# ACTive case studies

## Using downhole measurements to boost well performance:

Talisman Malaysia Ltd. operates more than 130 wells in the South China Sea, but many of them do not perform to full potential because of perforation damage at suboptimal reservoir conditions.

Initial attempts to solve the damage problem involved CT perforating with the well in an underbalanced condition. The main advantages of CT were the ability to lower the bottomhole pressure using nitrogen and a lower overall cost when compared to tubing-conveyed perforating using a standard rig.

Although conventional CT methods were considered effective in this application, concerns included perforating off-depth due to inaccurate depth control, an inability to detect fired guns and improper pressure balance in the well. Too much pressure in the wellbore could result in an ineffective cleaning of the perforations and too little pressure could cause the guns to be sanded in after they fired.

ACTive Perf was selected because the service provides downhole measurements, tools and techniques to perforate in properly balanced conditions. It also allows the accurate placement of the guns, a pressure activated electronic firing head system and the ability to receive real-time confirmation that the guns have fired.

The ACTive Perf system was used to complete a TML offshore gas well. The perforating gun was positioned on depth using real-time CCL correlation. Prejob calculations showed that the correct underbalance would be reached after the displacement of wellbore fluid with nitrogen. However, when real-time pressure data showed that the desired underbalance pressure had not been achieved, operators were able to respond immediately to correct the problem.

Nitrogen pulses were sent down through the coiled tubing to fire the guns. Downhole measurements quickly showed an increase in bottomhole temperature and pressure, which confirmed a successful firing.

By perforating under optimal reservoir conditions, TML achieved a higher-than-expected and sand-free gas production rate of 70 MMcf/d.

Company Profile

# Coiled Tubing Units, Nitrogen and Coiled Tubing Support Equipment

NOV Hydra Rig is the recognized world leader in coiled tubing units, nitrogen and coiled tubing support equipment, having supplied more coiled tubing units than all current manufacturers combined.

National Oilwell Varco's Hydra Rig Division couples advanced technologies with proven high-quality components, service and technological expertise to provide the single source for all of your well intervention requirements worldwide. NOV Hydra Rig delivers the complete CT equipment advantage with brand names relied upon for more than 30 years and is constantly developing new and innovative solutions for all of your future CT requirements.

*Coiled tubing drilling operation utilizing an NOV Hydra Rig coiled tubing unit and nitrogen unit, NOV Texas Oil Tools pressure control equipment, NOV CTES data acquisition system, and an NOV Rolligon twin fluid pumper.*

NOV Hydra Rig

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# Coiled Tubing (CT) Pressure Control Equipment

### NOV Texas Oil Tools

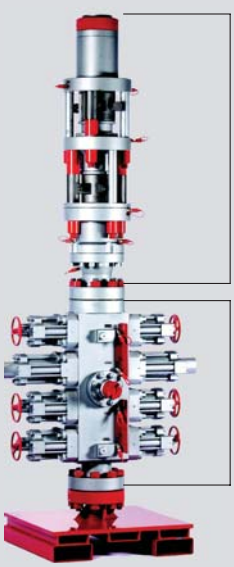
Since its founding in 1978, Texas Oil Tools (TOT) has established itself as one of the leading specialty manufacturers and suppliers of pressure control equipment. During this period, TOT has expanded its range of products to meet the dynamic demands of the industry.

A proven track record of excellence in design, manufacturing and service has gained NOV Texas Oil Tools worldwide recognition as a leader in pressure control products. We design and manufacture our products to the most stringent standards. We are a licensed API manufacturer and supply our equipment to meet or exceed industry standards.

Our product range begins with 1.50" bore and goes up to 9.00". In addition, our spectrum of products exhibit working pressures up to 20,000 psi and temperature ranges from -75°F arctic service to 500°F geothermal applications.

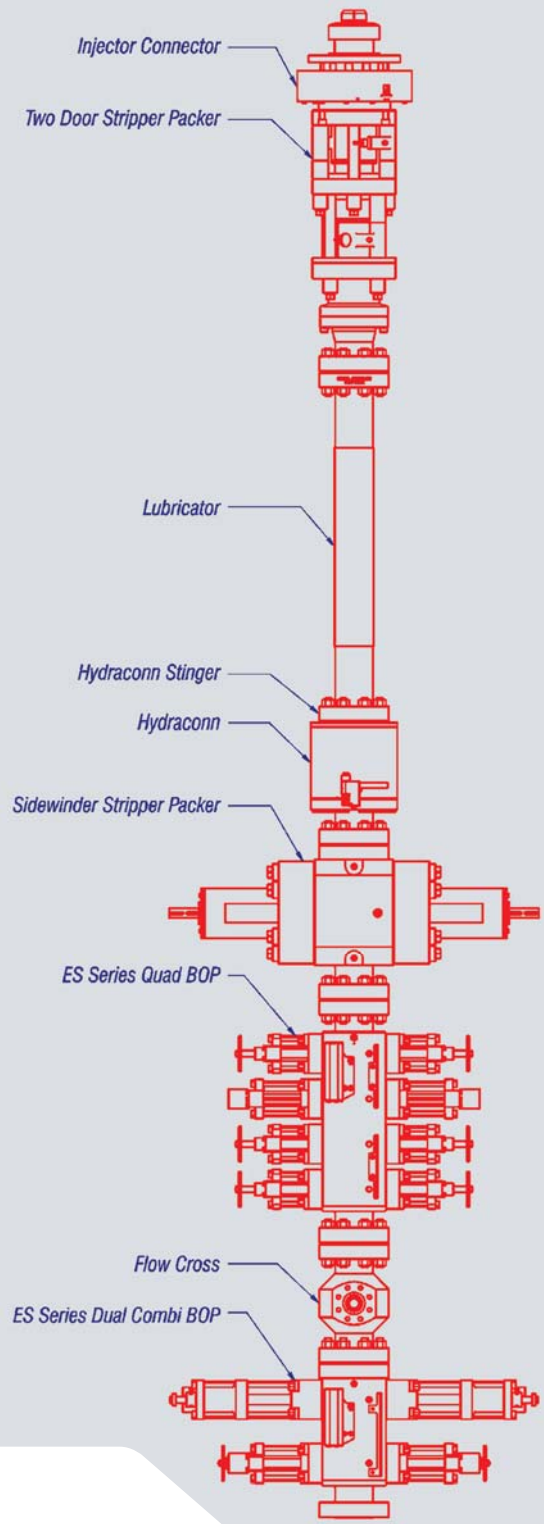
### NOV TOT CT Pressure Control Equipment

- **Blowout Preventers**
  Single, Dual, Triple, Quad, Quint, and Combi Ram Designs
- **Stripper Packers**
  Side Door, Sidewinder, Conventional, Tandem Side Door, Over/Under, Two Door
- **Quick Latches**
  Hydraconn, Injector Connector, Quick Disconnect, Hydraulic Releasing Connector (JHS)
- **Additional Equipment Offered:**
  - Flanges
  - Flow Cross
  - Hand Unions
  - Lubricators
  - Safety Valve
  - Transport Lift Frames
  - Tubing Punch
  - Tubing Shear



**Two Door**
**Stripper Packer**
NOV Texas Oil Tools has enhanced the Over/Under design to have two easy access doors. The new Two Door Stripper packer provides two packers in one Stripper with easy replacement and extended life packers.

**"ES" BOP**
**3.06", 4.06", 5.12", and 7.06"**
This is a lightweight, high pressure coiled tubing BOP package. Features include hydraulic ram change, balanced shear piston and combi shear seal and pipe slip ram capabilities.

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Company Profile

# Tenaris offers the most diverse line of coiled tubing for downhole applications

Tenaris is the leading manufacturer of coiled tubing products worldwide. At its two Houston facilities, the company manufactures coiled tubing and coiled line pipe in a range of sizes and grades, including corrosion resistant alloys for sour service environments. As a result of Tenaris' capabilities, Schlumberger chose the company to be its exclusive provider of coiled tubing for their global coiled tubing services organization.

Tenaris has differentiated its product offerings by not only supplying coiled tubing strings used for downhole production-related coiled tubing services, but also through manufacturing of larger coiled tubing that may be utilized for marine pipeline requirements. The company is the world's first tube or pipe manufacturing facility to obtain ISO-9001 certification for its quality assurance programs. Tenaris is the world's only supplier of 4 ½-in. and 5-in. OD coiled tubing and the sole provider of heavy wall coiled tubing with available thickness from 0.224-in. to 0.300-in.

Additionally, Tenaris operates the world's only dedicated three-layer continuous coating line for coiled line pipe, consisting of fusion bonded epoxy, copolymer adhesive and polyethylene or polypropylene. The coiled line pipe is delivered on spools to marine vessels where they are consolidated to enable the vessel to pay out the tubing significantly faster compared with conventional stick pipe welded joint by joint and laid by a traditional pipelay vessel.

Coiled line pipe typically is used in water depths of 200-3,000 ft. with one Gulf of Mexico installation in more than 7,000 ft. of water and other projects in locations from Norway to New Zealand. Tenaris also pioneered the API 5LCP coiled line pipe certification standards, and continues to be the only certified supplier.

### Continuously setting records

The company holds numerous production records for the longest and heaviest coiled tubing service work strings, all of which have been in conjunction with Schlumberger as its global alliance supplier of coiled tubing.

- A project in the Gulf of Mexico calling for 28,900 ft of 1 ½-in. high strength (HS) 110 tapered coiled tubing;
- A Gulf of Mexico project requiring 32,600 ft of 2-in. tapered coiled tubing, plus a second 33,300 ft tapered string of 2-in. HS 110 tubing. The strings have seven wall thickness transitions from 0.204-in. to 0.125-in. The project took two years to develop, including six months of pre-planning and the manufacturing of two mini-strings to test bias welds;
- A third Gulf of Mexico project for Schlumberger required 30,600 ft of 1 ¾-in. HS 110 coiled tubing;
- A project offshore eastern Canada called for 30,200 ft of 2-in. HS 90 coiled tubing with electric line cable for logging equipment.

### Optimizing manufacturing process

Tenaris' coiled tubing plant in Houston went through a debottlenecking and expansion program from late 2005 through spring 2007, significantly improving workflow as well as adding the latest technology to increase production efficiency. The expansion project also improved service handling and simplified truck traffic flow through the plant.

Improvements included increased assembly lines, additional assembly consolidation wheels, which dramatically reduced the amount of time the coiled tubing was in the assembly area, and the addition of digital radiography technology to reduce the time for welds and inspection by 50% compared with the older film processing technology.

Two heavy-duty overhead crane systems were installed providing for safer and more reliable transportation of the coiled tubing strings throughout the plant. There are more and larger spooling reels available for long coiled tubing strings, and additional hydro test bays were built. The expansion program increased output by 75%-80% and significantly reduced backorder time. There also is additional infrastructure to allow for further expansion, including a third mill and bias welding cells as well as room for onsite master coil slitting.

Tenaris continuously works with other innovative companies to develop new applications for coiled tubing and coiled line pipe. The forward thinking company is currently testing the applicability of large diameter coiled line pipe for marine riser applications, unique artificial lift products, and tubular products as subcomponents for more advanced production equipment for tertiary and SAG-D production.

Tenaris is a leading supplier of tubes and related services for the world's energy industry and certain other industrial applications. Its mission is to deliver value to its customers through product development, manufacturing excellence and supply chain management. The company minimizes risk for its customers and helps them reduce costs, increase flexibility and improve time-to-market. Tenaris' employees around the world are committed to continuous improvement by sharing knowledge across a single global organization.

Tenaris

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