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NORTH AMERICAN OUTLOOK

U.S. drilling plateaus, despite high oil prices

OIL COUNTRY TUBULAR GOODS

Incorrect testing after manufacturing may cause brittle failures

SHALE TECH: EAGLE FORD

Play extends beyond the core to Eaglebine and Pearsall

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ABOUT THE COVER

Drilling underway in McMullen County's AWP field, where Eagle Ford operator Swift Energy is focusing on liquids-rich production. Photo courtesy of Swift Energy.

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www.iri-oiltool.com

World Oil®

Mailing Address: PO Box 2608
Houston, TX 77252-2608, USA
Phone: +1 (713) 529-4301
Fax: +1 (713) 520-4433
WorldOil.com

PUBLISHER Ron Higgins

EDITORIAL

Editor Pramod Kulkarni
Executive Editor Kurt Abraham
News Editor Melanie Cruthirds
Associate Editor John Betz
Contributing Editors
Dayse Abrantes, Brazil
Dr. A. F. Alhajji, Middle East
Dr. Roger Bezdek, Washington
David Blackmon, Production
Robert Curran, Canada
Dr. Ali Daneshy, Shale Technology
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Dr. William J. Pike, Exploration
Jim Redden, Drilling
Dr. Jacques Sapir, FSU
Richard R. Vernotzy, PE, Offshore
Russell Wright, At Large

MAGAZINE PRODUCTION / +1 (713) 525-4633

Vice President—Production Sheryl Stone
Manager—Advertising Production Cheryl Willis
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Artist/Illustrator David Weeks
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ADVERTISING SALES

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Article reprints: *World Oil*, Cheryl Willis, Gulf Publishing Company, Advertising Production Manager. 2 Greenway Plaza, Suite 1020, Houston, Texas 77046. Phone: 713-525-4633. Fax: 713-525-4615. Email: cheryl.willis@gulfpub.com.

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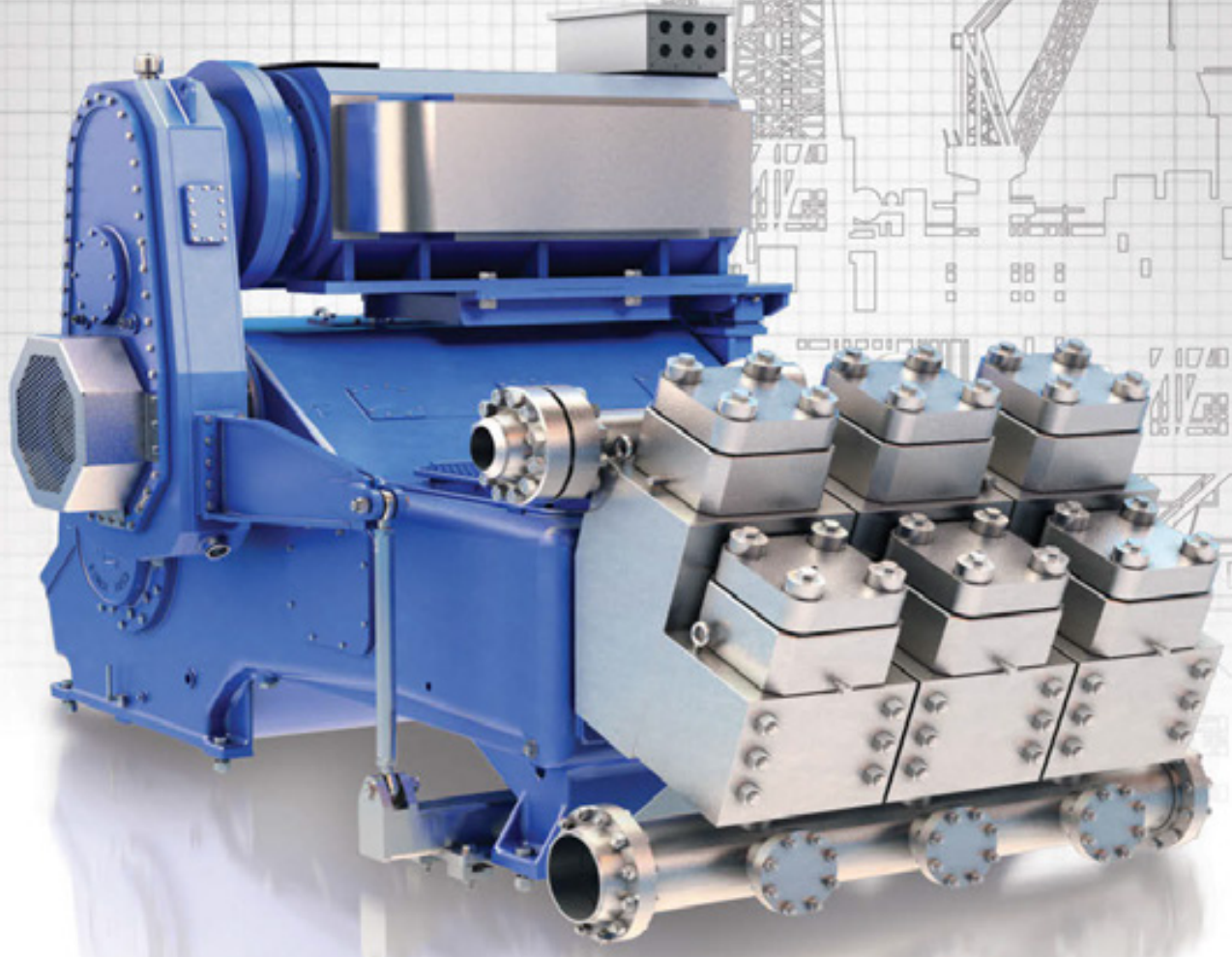
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PRAMOD KULKARNI, EDITOR



Shakespearean farce in the swamps

"The first thing we do, let's kill all the lawyers."

—Dick, the butcher, in *King Henry The Sixth*, by William Shakespeare.

At the risk of annoying lawyers at large, I am of the same opinion as Dick, the butcher, at least in the case of two sets of lawyers in Louisiana. The first set belongs to the Plaintiff's Steering Committee that BP says is disbursing funds to businesses that did not suffer losses from the Gulf spill. The second set of lawyers represents the Southeast Louisiana Flood Protection Authority-East (SLFPA-E), and has filed a suit against nearly a hundred oil and gas companies for allegedly damaging the coastal wetlands in southeast Louisiana.

If Dick, the butcher, were alive today, he would be inclined to arrange for a public hanging. Mindful of the U.S. Attorney General's assurances to Russia that the U.S. would neither pursue a death penalty against National Security Agency (NSA) whistleblower Edward Snowden nor torture him, the highest punishment I can hope for is a whack on their collective wrists with a wet noodle.

Paying legitimate claims. In the aftermath of the Gulf spill, BP has paid over 300,000 claims worth $11 billion through a compensation process administered by Kenneth Feinberg. The Plaintiff's Steering Committee consists of lawyers, who have persuaded their clients to skip the Feinberg process and press their claims against BP through lawsuits. BP even settled with this steering committee, expecting the additional claims to total about $7.8 billion.

Joe Nocera, columnist for *The New York Times* (no friend of the oil and gas industry), reports that through the committee "businesses that not only weren't affected by the BP disaster, but hadn't even suffered losses, were getting millions of dollars. Some had seen increased profits during the oil spill—and still got money. Lawyers started trolling for new clients, trumpeting the fact that claims didn't have to have any connection to the disaster." It remains to be seen whether BP can use the appeals process to put a stop to what it politely calls a "misinterpretation" of the settlement process. As acknowledgment of the futility of protesting against the exorbitant payments, BP has increased its allocation for additional payments to $9.6 billion.

Lawsuit for a bonanza. In late July, trial lawyers, representing the SLFPA-E, filed a lawsuit against 97 oil and gas companies, charging them with inflicting severe damage on fragile coastal wetlands.

The tiny SLFPA-E board's action sidesteps the state's $50-billion, 50-year coastal protection and restoration Master Plan, which outlines how the state and localities will restore wetlands and improve flood protection in the New Orleans area and elsewhere along the state's coast. Governor Bobby Jindal criticized the lawsuit, through a statement saying the levee board had overstepped its authority, and would damage Louisiana's ability to effectively tackle coastal issues.

"This is nothing but a windfall for a handful of trial lawyers," Jindal said. "It boils down to trial lawyers, who see dollar signs in their future and, who are taking advantage of people, who want to restore Louisiana's coast. These trial lawyers are taking this action at the expense of our coast and thousands of hardworking Louisianians, who help fuel America by working in the energy industry."

We readily agree with Gov. Jindal. Protecting the coastland is everybody's responsibility. If there are specific instances of damage, such incidents can be resolved outside the courts. If the lawyers want to restore Louisiana back to the way it was before a century of developments, they will have to take a pirogue to the courthouse, while fanning themselves with their filing papers. Even William Shakespeare will declare it to be poetic justice. WO

IN THIS ISSUE

39 Refracturing horizontal shale wells with solid-expandable liners. Featured in our Oil Country Tubular Goods section is an article by an Enventure author, who explains how shale laterals can be refractured more effectively using an expandable liner than other methods of perforation isolation, such as cement squeezing or plugging with sand. The article presents successful refracturing case studies from the Barnett shale plays.

65 North American mid-year forecast update. While oil prices have been high and gas prices are rising from historic lows, the U.S. rig count is oscillating within a narrow band around 1,750 rigs. Activities in Canada and Mexico are in a similar holding pattern. Executive Editor Kurt Abraham provides an analysis of well data from the state agencies and explains how the operators remain in cautious in anticipation of possible regulatory restrictions or changes in tax allowances and credits.

C-127 Advances in Coiled tubing supplement. With each passing year, we see increasingly innovative applications for coiled tubing beyond its routine use as a drilling and completion intervention tool. The increasing application range is the result of sturdier coiled tubing and greater reliability due to sophisticated computer modeling methods to test coiled tubing fatigue under actual field conditions. *World Oil* coiled tubing supplement this year includes articles describing how coiled tubing was used for challenging acid stimulation of deep, HPHT sour-gas multilateral wells, and for reducing water usage during hydraulic fracturing.

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DISCOVERIES

GDF Suez makes West of Shetlands gas discovery

GDF Suez E&P UK has confirmed that the Cragganmore exploration well was a successful gas discovery. In Block 208/17, this is one of two wells drilled in the West of Shetlands, in partnership with DONG Energy as operator. The Cragganmore well results are being evaluated to assess viability and determine further activity. The second well, Glenrothes, in Block 208/11, has been plugged and abandoned, having reached a TD of 4,295 m. The water depths of the wells were 673 m for Cragganmore and 1,169 m at Glenrothes. The drilling campaign commenced at the end of 2012, and continued into early 2013. In the West of Shetlands, GDF Suez secured its first license as operator, with three other firms as partners, in October 2012. The company now holds seven licenses in the West of Shetlands province. The company's next exploration well in the region is planned for 2015. GDF Suez is a partner (30%) in the exploration wells at Glenrothes and Cragganmore. DONG Energy is the operator (40%), and Dana Petroleum is also a partner (30%).

BG Group raises Tanzania gas estimate after offshore find



BG Group raised its estimate for total gross recoverable resources of natural gas from its Tanzania discoveries to around 13 Tcf, following its eighth consecutive find off the East African country's coast. Increasing the estimate from 10 Tcf underscores the region's importance as one of the energy industry's hottest new areas. Neighboring Mozambique, with its discoveries of giant offshore gas fields, aims to export its first cargoes of LNG by 2018. Analysts say the region is well-placed to serve growing energy demand in Asian markets. The mounting volume of gas discoveries off the coast of East Africa has already stimulated a wave of multi-billion-dollar acquisitions in projects in Mozambique. BG Group said that its eighth consecutive gas discovery offshore Tanzania occurred in July, in the Ngisi-1 exploration well in Block 4. The Ngisi well is the first to penetrate a reservoir section adjacent to the previously announced Pweza and Chewa discoveries in Block 4, opening up a new play in the tertiary formation of the northern block. BG Group is in the process of selecting a site for an onshore LNG plant, and said that the process was progressing well. Terminal capacity will be determined by further exploration and appraisal results across the company's three offshore blocks.

Oil Search encouraged by PNG gas discovery

Oil Search said that it discovered modest quantities of natural gas during a new exploration campaign in Papua New Guinea (PNG), but that the find had encouraged it to continue drilling. Oil Search began looking for gas in the Gulf of Papua this year, as part of a campaign that may help it develop another gas export plant in the impoverished Southeast Asian nation. The Australian company is already a major shareholder in the $19-billion Papua New Guinea LNG export project, led by ExxonMobil. Oil Search said in a statement that its Flinders and Hagana wells in the Gulf of Papua intersected good-quality geological properties that may indicate the presence of larger resources nearby. Hagana is still drilling ahead to its target depth.

CNOOC hits two discoveries in Bohai bay

CNOOC Limited has struck two new discoveries, Bozhong 8-4 and Kenli 10-4, in Bohai. Bozhong 8-4 is on the west slope of Bozhong Sag in Bohai bay, with an average water depth of about 28 m. The discovery well, Bozhong 8-4-4, was drilled and completed at a depth of 1,962 m, and encountered oil pay zones and a gas reservoir with total thickness of about 50 m and 11 m, respectively. During the test period, the well's oil production was around 660 bopd. Kenli 10-4 is on the southern slope of Laizhou Bay Sag in Bohai, with an average water depth of about 15 m. The discovery well, Kenli 10-4-1, was drilled and completed at a depth of 2,395 m, and encountered oil pay zones with total thickness of about 45 m. During the test period, the well's oil production was around 2,800 bopd.

BUSINESS

Wintershall raises Norwegian production with Statoil deal



Wintershall will increase its production in Norway from 3,000 boed to almost 40,000 boed, with the closing of an asset swap with Statoil for shares in Brage (32.7%), Vega (30%) and Gjøa (15%) fields. The effective date of the transaction is Jan. 1, 2013. In addition, at Brage, Wintershall will take over operatorship of a major production platform on the Norwegian Continental Shelf for the first time. Transfer of the operatorship from Statoil to Wintershall is planned for Oct. 1, 2013. In return, Statoil will receive a 15% share in the Edvard Grieg development project from Wintershall, and financial compensation of $1.35 billion. The compensation payment is being offset by the earnings derived from the share in production from Brage, Vega and Gjøa since Jan. 1, 2013. An additional payment of up to $100 million will be paid by Wintershall, contingent on the successful future development of Vega field. As part of the transaction, the two companies also agreed to conduct joint research activities into EOR, and to work together in researching unconventional hydrocarbon deposits in Germany and other regions. Photo courtesy of Øyvind Hagen/Statoil.

Nigeria LNG resumes normal operations, lifts force majeure on exports

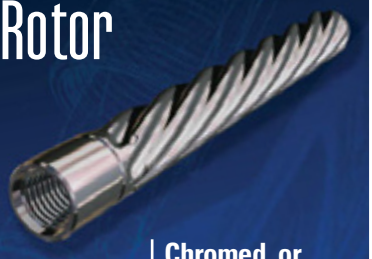
Nigeria LNG said on July 26 that it had lifted force majeure on its LNG exports, two weeks after Nigeria's maritime regulator lifted a blockade of the company's operations amid a tax dispute. Nigeria LNG declared the force majeure, effective June 28, after a blockade by the Nigerian Maritime Administration and Safety Agency, or NIMASA, prevented LNG tankers from accessing the company's loading terminal on Bonny Island in the Niger Delta region. The blockade was the result of a long-running dispute over the payment of duties on freight and exports. The blockade, imposed on June 21, was lifted in July after Nigeria LNG was ordered by the government to pay about $159 million to settle levies allegedly owed to NIMASA from October 2009 to May 2013, and to continue paying the levies going forward. Nigeria LNG said it made the payment "under protest." Nigeria LNG is a JV between Nigeria's state oil company, NNPC, and Shell, Total and Eni.

Shell approves new deepwater Brazilian projects

Shell, with its partners, expects to boost production with two new deepwater projects at Brazil's Parque das Conchas (BC-10) and Bijupirá/Salema fields. For Parque das Conchas (BC-10), Shell, with Petrobras and ONGC, has decided to move forward with Phase 3 of the project, which will include installation of subsea infrastructure at Massa and Argonauta O-South fields. These fields will be tied back to the *Espírito Santo* FPSO, at the center of the Parque das Conchas development. Once online, Phase 3 of the BC-10 project is expected to reach peak production of 28 Mboed. Since coming onstream in 2009, the BC-10 project has produced more than 70 Mboe. Phase 2 of the project continues to progress and is expected to come online in late 2013 with peak production of 35,000 Mboed.

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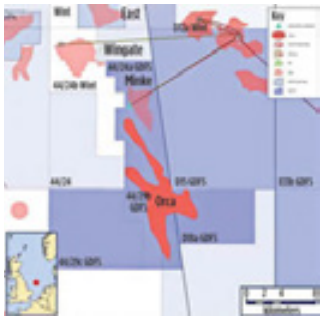
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PRODUCTION

Major milestone completed on the Orca project



The project partnership operated by GDF Suez E&P, of which RWE Dea UK is part, completed the installation of the platform to develop Orca gas field in the southern North Sea. The first development well was spudded, and first production from Orca is expected in late 2013/early 2014. Installation of normally unmanned platform D18a-A was successfully completed by the installation vessel, *Oleg Strashnov*. The platform is in the Dutch sector, 500 m from the UK sector, in approximately 40 m of water. It is designed to produce natural gas from up to six wells.

Lundin Petroleum enters into new PSC offshore Indonesia

Lundin Sareba has entered into a production-sharing contract (PSC) with SKKMigas to substitute the existing Sareba Block with new acreage, named Cendrawasih VII, offshore northeastern Indonesia. Under the amended agreement, Lundin is awarded the new acreage, as a result of the existing block being declared a protected nature conservation area. The CVII Block covers an area of approximately 5,545 sq km, and has been lightly explored. The block contains the shallow-water portion of the Mamberamo delta and an undeveloped gas discovery in Pliocene turbidite reservoirs. Large carbonate build-ups have also been identified on a 950-sq-km, 3D seismic survey acquired in 2009, and which Lundin expects to reprocess prior to possible future drilling.

Shell's Olympus platform departs for deepwater Mars field

Shell's massive Olympus tension leg platform (TLP) set sail from Ingleside, Texas, for a 425-mi trek to its final home on the Mars field in the Gulf of Mexico. For 10 days, tugboats will have transported the more-than-120,000-t platform to location, where work will begin to secure the platform in place. The Olympus TLP will be moored to the seafloor by tendons grouped at each of the structure's corners, and will float in approximately 3,000 ft of water. Olympus is Shell's sixth and largest TLP, and will provide process infrastructure for two of Shell's deepwater discoveries, West Boreas and South Deimos. The project also includes pipelines that will be routed through West Delta 143C, the recently installed shallow-water platform. The Olympus TLP is expected to start production in 2014, producing at a maximum rate of 100,000 boed.

ACQUISTIONS & EXPANSIONS

Halliburton acquires distributed acoustic sensing systems provider

Halliburton has completed acquisition of the assets of Optiphase, a provider of interferometric fiber optic sensing solutions, including distributed acoustic sensing (DAS) interrogation systems. The terms and cost of the acquisition were not disclosed. DAS technology turns a piece of fiber optic cable, similar to what one would use for cable or telephone service, into a fully distributed noise logging system. When applied to an oil and gas well, operators can tune in to any section of the fiber, and listen to what is happening in their well. Applications include stimulation and production monitoring, verification of downhole equipment operation, pipeline monitoring and collection of seismic data. Optiphase joins the ranks of Halliburton's other fiber optic assets.

Acteon acquires UK-based J2 Engineering Services

Acteon has completed the acquisition of J2 Engineering Services. The Aberdeen-based company is involved in the rental, maintenance and repair of ROV manipulator arms, and associated tooling and equipment. J2 Engineering's service offering runs along very similar lines to that of well-established Acteon company Seatronics, a provider of subsea electronic equipment to the offshore and ocean industries. J2 Engineering and Seatronics have already collaborated successfully on a number of projects. The J2 Engineering team will continue to operate from its premises in Torry, Aberdeen.

HSB Solomon Associates acquires large consulting firm

HSB Solomon Associates, a performance improvement company, has acquired Ziff Energy Group, an international energy consulting firm. The transaction adds global E&P benchmarking and North American natural gas forecasting to Solomon's suite of products and services. The terms of the transaction were not disclosed. Ziff, with offices in Calgary and Houston, focuses principally in two areas: E&P studies across 40 countries, covering more than 4,300 production fields, and gas services in North America. Its gas services include in-depth analysis of North American and regional markets, gas and liquids supply, transportation, midstream, storage, regulatory affairs and long-term gas pricing forecasts.

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Switching from an extralarge-diameter conventional sampling probe to the Saturn 3D radial probe, an operator in the Middle East acquired fluids from a low-permeability dolomite at 6.5× the flow rate and ⅓ of the drawdown to confirm mobile oil where openhole logs were inconclusive.

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slb.com/saturn

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EXPLORATION

Drillship sets water-depth record offshore India



Transocean's ultra-deepwater drillship, *Dhirubhai Deepwater KG1*, has set a new world record for the deepest water depth operated by an offshore drilling rig. The rig recently spudded a well in 10,411 ft of water, while working for ONGC off the east coast of India. This accomplishment surpasses Transocean's prior world record of 10,385 ft of water, also set by *KG1* while working for ONGC in India during February.

BGP deploys nodes for game reserve seismic project

BGP has deployed 15,100 of FairfieldNodal's ZLand nodes for a 3D seismic acquisition project in the Murchison Falls National Park and Game Reserve in Uganda. The project marks the largest seismic acquisition ever allowed in this, or any, of the country's nine parks and game reserves. The Murchison Falls area is an extremely sensitive environment, attracting large numbers of wild game. The seismic equipment being used for the survey must be as invisible as possible to ensure the protection of the wildlife, as well as that of the seismic acquisition itself. The seismic project, being done for Total, is expected to last for a year.

First data sets released ahead of licensing round in Greece

PGS has acquired 2D multiclient data offshore western and southern Greece for the country's Ministry of Environment, Energy and Climate Change, and the first fast-track datasets are now available. Given the recent results of other Mediterranean plays, this offshore area, which is the subject of an upcoming licensing round, shows great potential. The objectives of the acquisition program are to improve understanding of regional structure and depositional basins, and identify petroleum systems in advance of the licensing round in Greece, scheduled for mid-2014.

GOVERNMENT

Jindal demands East Bank levee authority drop lawsuit

Saying that it had overstepped its boundaries, Louisiana Gov. Bobby Jindal is demanding that the East Bank levee authority drop a lawsuit, filed July 24, that would require producers and pipeline companies to restore damaged wetlands, and pay damages for the effects of lost wetlands on levees. Jindal also demanded that the Southeast Louisiana Flood Protection Authority-East fire the attorneys, who filed the suit, saying they were hired in violation of state law, which requires that their hiring be approved by the governor. The state's $50-billion, 50-year coastal protection and restoration Master Plan outlines how the state and localities will restore wetlands and improve flood protection in the New Orleans area, and elsewhere along the state's coast. In interviews, and at a news conference announcing the lawsuit, authority V.P. John Barry and attorney Gladstone Jones said that any restoration and improvements resulting from the lawsuit would have to comply with the Master Plan. In a statement responding to Jindal, Barry defended the authority's action in filing the lawsuit, and challenged the governor's allegation that it had been improperly influenced by trial lawyers. Barry said that the lawsuit decision, and the decision to hire trial lawyers, had been properly vetted.

Brazil antitrust agency to decide if OGX and Petrobras violated law

Brazil's antitrust agency, Cade, will soon decide whether OGX, controlled by entrepreneur Eike Batista, and Petrobras, violated the antitrust law in a deal announced in November 2012, the agency said. At the time, Petrobras said that it agreed to sell its 40% stake in the BS-4 oil block to OGX for $270 million. The block contains two oil fields, and is 185 km off the Brazilian coast. Cade's press office said, in an email, that the agency will investigate to see whether the deal has been concluded in violation of Brazil's antitrust law. If the agency decides that there has been what they call "gun-jumping," or having finalized the deal without Cade's approval, the companies may be subject to fines of between $27,000 to $2.6 million, according to Cade.

Ecuador delays bid deadline for 11th round

For a second time, Ecuador has extended the deadline for companies interested in the country's 11th oil licensing round to submit offers to explore for oil in blocks in the southeastern Amazon region, the Ministry of Nonrenewable Natural Resources said. The original deadline to submit offers was the end of May, but, in April, the government of President Rafael Correa extended the deadline to mid-July. Now, the government has extended the deadline again, to the end of November. The licensing round was called last November for 13 oil blocks in Pastaza and Morona Santiago provinces, near the border with Peru. As part of the licensing round, state oil company Petroamazonas also plans to negotiate directly with foreign state-owned companies, to develop three other blocks in the area.

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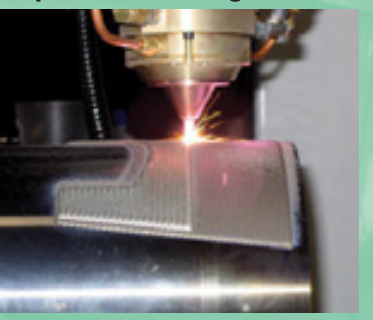
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DR. WILLIAM J. PIKE, EDITORIAL ADVISORY BOARD CHAIRMAN



A photo worth a thousand rock properties

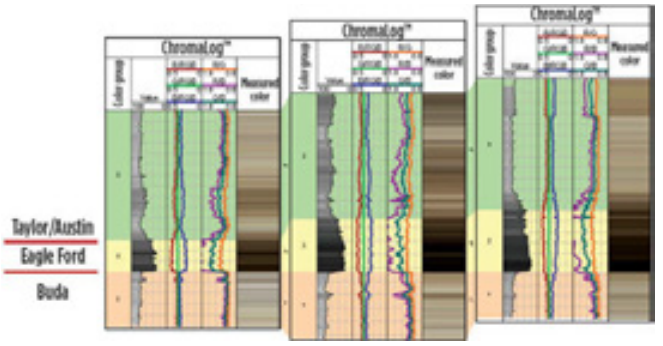
I am an avid photography enthusiast. I have been since my teens. I have plenty of pictures of rigs in sunsets, in sunrises, in storms offshore and myriad other scenarios, not to mention pumping units silhouetted against purple West Texas skies. It never occurred to me, however, that cameras and the familiar red, green and blue spectrum might find a use in the oil and gas industry outside beautiful pictures.

Fortunately, it did to the folks at Ellington & Associates, a geoscience laboratory and wellsite services company specializing in paleontology and rock analysis in Houston. Specifically, they have put photography to work evaluating cuttings to help determine stratigraphic well correlation on the fly at the wellsite through worldwide mudlogging companies, and after the fact, in the lab. They have named this patented method and service: Chromastratigraphy.

Chromastratigraphy is stratigraphic service that studies how changes in the color of lithologic strata relate to the changing composition of the strata, and the quantification of these changes to identify stratigraphic variation. By accurately recording and reproducing the stratigraphic colors, a visual record of the stratigraphic column can be created from ditch cuttings or core samples. Chromastratigraphy relies on the changing abundance and composition of rock forming constituents; principally, minerals, organic molecules and compounds, and cementing agents. As the relative abundances of these constituents change, the perceived color of the sample will likewise change. Color is measured by digitally recording the electromagnetic spectrum of each sample in the near ultraviolet-visual, near infrared range (the wavelengths humans can perceive, from approximately 390 nm to 750 nm).

In addition to more common logs, the technology can be a standalone stratigraphic correlation tool and, in many areas, a substitute or proxy for TOC and paleo events. The potential of this service is to combine it in geosteering programs as a second data point in troubled lithologic areas.

Fig. 1. Correlation can take place on a local-to-basin scale. Chromatic changes can be linked to geochemical, paleo, wireline or other geological data.



For years, Ellington observed significant color variations while processing washed well cuttings and core rock samples. Early on, these variations were not investigated because there was no accurate way to define the observed color changes, or to measure them. The use of color as a descriptive tool for geologic samples has traditionally relied upon qualifying modifiers such as "light" and "dark" to describe the varied range of rock values and hues. Attempts at more systematic methods have relied upon descriptive systems, such as Munsell Soil Color Charts, but, without graphical methods to display the data, it was difficult to identify and see patterns. In 2010, the company decided to determine if sample color could be captured digitally, standardized, and used as a correlation tool. The result was a procedure using protocols and software to prepare and analyze well samples for color. The analyses provide the following information:

- Quantifies variations and changes in color observed in strata;
- Provides accurate color and spectral measurements;
- Spectroscopic data is transformed into readable well log information;
- The subjectivity of traditional lithological descriptions (i.e., "light gray") is removed, and;
- Results are repeatable and reproducible.

A number of factors influence the observed and measured colors. Mineralogy and thermal history are key, as is lithology, specifically including grain size and cementation. Geochemistry also has a large influence on color, due to inorganic compounds (sulfides, etc.), organic compounds (TOC), redox conditions at deposition (i.e., anoxia) and post-depositional chemical alteration.

The analytical process begins with raw cuttings samples delivered from the rig, which are carefully washed, finely ground and mixed with water to fully hydrate them. The resultant slurry is photographed under carefully controlled light in specially-designed photographic chambers using a digital camera and a spectrophotometer. The RGB spectrum of the image is then processed, analyzed, and a gray-scale correlation generated. Together, the RGB analysis and gray-scale index indicate minerology, lithology, TOC and thermal maturity that are correlated with depth.

The ChromaLog can be integrated with traditional gamma-ray logs for log correlation and additional definition. On a larger, regional scale, Chromastratigraphy logs can be used for regional stratigraphic correlation such as illustrated in Fig. 1 showing distinct, correlatable changes in the Austin-to-Buda formations in the South Texas Eagle Ford play. WO

WILLIAM.PIKE@CONTR.NETL.DOE.GOV / BILL PIKE has 45 years' experience in the upstream oil and gas industry, and serves as Chairman of the *World Oil* Editorial Advisory Board. He is a consultant with Leonardo Technologies and works, under contract, in the National Energy Technology Laboratory (NETL), a division of the U.S. Department of Energy. His role includes analyzing and supporting NETL's numerous R&D projects in upstream and carbon sequestration technologies.



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JIM REDDEN, CONTRIBUTING EDITOR



A futures market for cuttings?

The outlying stench was wholly incompatible with the perfectly manicured meadows, rolling vineyards and lush botanical gardens, all within the shadows of regal Mt. Taranaki and abutting one of the world's most pampered coastlines. Well north of bucolic New Plymouth, on New Zealand's North Island, the pungent smell of decaying and burning wastes provided a less-than-inviting welcome, as we pulled off rural Highway 3 and into the Uruti Composting facility.

Among the myriad rubbish being remediated were symmetrical, tarpaulin-covered rows that could easily be mistaken for an everyday vegetable garden, save for the nose-pinching odor and the resulting crop. For there, beneath the coverings, thousands of common earthworms chowed down on drill cuttings generated from a specially formulated M-I SWACO paraffin-based drilling fluid. During the April 2008 site visit, it was explained that the collective end-result of the creatures' digestive process was commercial-grade fertilizer that found an eager market with area garden centers and the local government, which used the nutrient-rich product for community landscaping.

The pilot project represented the first attempt at using vermiculture to convert cuttings from a waste product to a marketable resource. Five years on, worm-driven drilling waste management may still seem like an out-of-the-box methodology to some, but with reducing the volume and costs of the well construction waste stream even more de rigueur, it appears that any proposal not utterly implausible will remain on the table. Owing in no small part to the ramp-up in shale exploration, nearly all the investigations into beneficial reuse of cuttings have focused on using the erstwhile waste in more straightforward applications, such as bases for lease roads and drilling pads. However, that has not stopped folks from continuing to propose more unconventional recycling treatments.

British cuttings patent. Last December, the UK's World Intellectual Property Organization (WIPO) published a patent application that Aberdeen-based Total Waste Management Alliance Ltd filed last summer, which calls for using North Sea drill cuttings in plastics manufacturing. The integrated drilling waste management company said that the patent-pending process would treat and reuse much of the estimated 40,000 of contaminated cuttings shipped to shore each year from wells in the UK North Sea. The potential feedstock promises to increase exponentially, if the UK follows through and exploits its purportedly sizeable onshore shale reserves.

According to the filing, the process thermally treats the cuttings to extract entrained hydrocarbons, much of which, likewise, can be reused. Afterwards, the company's patented TCC RotoMill process can be used to grind the solids into an ultra-fine powder that is compressed and mixed with recycled plastic, to form pellets. The pellets are then used in the manufacture of bollards, planters, benches, decks and other rigid plastic products.

Making new roads. The new-age recycling options notwithstanding, most people agree that properly treated drill cuttings are intrinsically well-suited for use in laying down roads, drilling pads and the like. Such initiatives are gaining a receptive following in the U.S. shale plays, where transportation to often-remote disposal sites creates a host of economic and environmental headaches.

One of the more enduring projects has been in the Permian basin, where Scott Environmental Services of Longview, Texas, used specially treated water-based mud cuttings to construct a lease road. The access road has accommodated rig traffic for nearly five years with no side effects, said David Burnett, a director and research coordinator at Texas A&M University's Department of Petroleum Engineering, who has monitored the project since its inception. "We monitored to see if there was any dust or leaching. It does not leach out, and has held up well to the West Texas environment. It is very environmentally acceptable," said Burnett.

Scott uses its proprietary Firmus process, which is based on accepted solidification and stabilization technology, to treat cuttings from water, oil and saltwater-based muds for conversion into construction material for lease roads, drilling pads, compressor station pads, tank battery berms, and similar load-bearing structures.

According to the *San Antonio Express-News*, Scott has similar projects in Madison County, Texas, in the Eaglebine play, as well as in the East Texas portion of the Haynesville shale, the Granite Wash and elsewhere. The waste management company also is looking for opportunities for oil-based cuttings in the core EagleFord play. While the process would seem a natural fit for public roadways under constant assault by rig traffic, thus far the recycling option has been restricted to operator-controlled projects, such as lease roads and drilling pads.

In a related project, fellow Texas-based waste management concern, Polk Operating LLC, plans to begin operating a cuttings and liquids recycling facility in the heart of the Eagle Ford later this summer. The Polk Karnes R3 facility in Karnes County is designed to remediate oil-based mud cuttings into commercial road construction material. The facility also includes a saltwater disposal system that was recently permitted by the Texas Railroad Commission. The Bowie, Texas-based company operates a similar recycling facility in Jefferson County, Okla.

Polk spokesman Christopher Saenz said the facility now under construction will process and recycle more than 25,000 cubic yards/yr of drill cuttings, as well as over 25,000 bbl of liquids. WO

■ JIMREDDEN@SBCGLOBAL.NET / Jim Redden, a Houston-based consultant and a journalism graduate of Marshall University, has more than 38 years of experience as a writer, editor and corporate communicator, primarily on the upstream oil and gas industry.



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DAVID BLACKMON, CONTRIBUTING EDITOR



Solutions for upstream water usage proliferate

One of the challenging aspects of shale oil and gas development in the U.S. comes from the fact that some of the large shale reservoirs are located in areas that are arid or semi-arid. Some, like the Eagle Ford and Cline shales in Texas, and the Niobrara in Colorado, are affected by ongoing drought conditions. This reality can make the sourcing of water for hydraulic fracturing operations a difficult undertaking.

The good news is that the industry is becoming increasingly creative in recycling, conservation and water sourcing efforts as time goes on, allowing the development of America's incredible wealth of oil and natural gas shale resources to continue. The pre-existing water situation is unique to each part of the country, so solutions to water-sourcing challenges vary by region.

Regional solutions. The northeast Louisiana area, home to the Haynesville shale, has provided a good example in recent years. The underground water aquifers in that area were not capable of providing the water necessary to sustain rapid, initial drill-out of that play, so companies were forced to look for other options. Many companies with leaseholds near the Red and Sabine Rivers, which flow along the eastern and western perimeters of the Haynesville play area, were able to obtain adequate water from those large streams. Other companies in the play were able to purchase treated effluent water from the City of Shreveport, and treated wastewater from a large, nearby plant operated by International Paper Company.

In the Eagle Ford region, we see a much different situation. Most companies in the western two-thirds of that region are able to source water from the deep, prolific Carrizo/Wilcox underground aquifer, which is a blessing, since the only rivers in that region often run at little more than a trickle, especially during droughts. Some of the small communities in the area have begun to follow Shreveport's example, creating a new profit center by selling treated effluent water for oilfield use.

As is always the case in the oil and gas industry, advancing technology is also playing a key role in addressing water issues. Recycling and conservation have become key elements of the water equation in the oil patch. Smaller companies that own proprietary recycling systems have proliferated across the country, providing solutions in isolated areas.

Service company innovation. But larger oilfield service providers with multi-million-dollar, annual R&D budgets are also playing a major role. For example, in March, Halliburton announced the commercialization of a new integrated suite of water services called H2OForward. This water system formulates stable fracturing fluids that are able to work with water containing total dissolved solids (TDS) of up to 285,000 ppm, an advance that Walter Dale, Halliburton's Global Strategic Business manager of Water Management Solutions, refers to as "…a paradigm shift that negates the use of fresh water and meets the supply chain needs of the customer."

XTO Energy partnered with Halliburton in the use of the H2OForward system on a group of wells in Eddy County, N.M., and earlier this year issued a report that documents savings of between $70,000 and $100,000 per well, with no discernible loss of production.

FTS International, formerly Frac Tech, has a treatment and recycling technology that it calls Aquacor. One of the company's Aquacor units can clean up to 15,000 bbl (630,000 gal) of returned fracturing fluid each day. The company expects to have three of its systems in operation by year's end.

Baker Hughes offers a water management technology that it calls H2PrO. Tom Whalen, the company's V.P. of Water Management, recently told Reuters that, when the company introduced its product about 18 months ago, its customers initially expressed interest, but were slow to commit to using it daily. But, he said, "In the last 12 months, that's totally changed," and there are now more than 300 employees engaged in water management in North American shale plays.

Of course, one of the industry's ongoing challenges is to help the public and policymakers look at its overall water use in the context of, and compared to, society's other uses of water. In recent years, we've all seen factoids and slides comparing water used in the average hydraulic fracturing job to other uses, like crop irrigation, power generation, city drinking water and other societal uses that consume far more water. I've used many of those factoids, myself, in presentations and speeches.

One of the more compelling recent comparisons comes from the June 28 edition of *The Wall Street Journal.* The *Journal* cites a study compiled by a University of Texas instructor named Rusty Todd, who compared water used in Texas for hydraulic fracturing operations to the volume of water used by Texans for watering their lawns.

Todd's somewhat astonishing finding was that the amount used for lawn watering was 18 times the amount of water used in fracturing operations in Texas in 2011. Given the disproportionate attention paid by the news media to water used by the industry, that ratio is pretty amazing.

Yet, the reality for this industry is that public perception, largely impacted by media coverage, matters. And it matters even more when the subject is water, one of our most critical life-sustaining substances. So, in order to maintain the public's confidence and, ultimately, its license to operate, the industry is obligated to continue to find ways to conserve, recycle and source water.

Fortunately, a lot of very smart people at many of the industry's most innovative companies are involved in doing exactly that. WO

■ DAVID.BLACKMON@FTICONSULTING.COM / DAVID BLACKMON is a managing director of FTI Strategic Communications, based in Houston. Throughout his 33-year, oil and gas career, he has led industry efforts to develop and implement strategies to address key issues at the local, state and federal level. His stops along the way include stints with The Coastal Corp. Tesoro Petroleum, Hughes Texas Petroleum, Burlington Resources, Shell and El Paso Corp.



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RICHARD R. VERNOZTY, P.E., CONTRIBUTING EDITOR



Get it while drilling

Further to, and continuing from, the Forward Thinking Technology section of my column in the June 2013 issue of *World Oil*, operator asset teams are always looking for better ways to get as much advanced information from the wellbore and reservoir formation as they can. Achieving this with minimal risk and maintenance of safety is of upmost importance.

Technology for obtaining real-time formation information (commonly from log technology), while drilling, has improved over the years. These tools contain radioactive sources, which could be a risk during transportation, storage, and handling at the rig site, and which are potential environmental concerns. If lost/stuck in the wellbore, they would need to be recovered.

The continuation of this column, below, describes some forward-thinking technology that could possibly provide this information. Our industry has been successful over time, because we have continued to develop new technology to make operations safer, save more time, and improve cost-effectiveness, using best practices.

Forward-thinking technology. Managed Pressure Wellbore Control includes the drilling and completion phases of the well operation. Coupled with Formation-Pressure-While-Drilling (FPWD) measurements, it may provide an aid in setting boundaries, especially in HPHT exploration and exploitation wells.

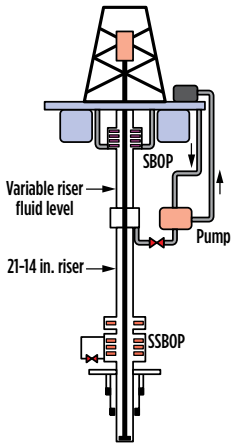
As regards underbalanced and managed pressure drilling (MPD), IADC has defined it as an adaptive drilling process, used to control the annular pressure profile precisely throughout the wellbore. It ascertains the downhole pressure environmental limits and manages the annular hydraulic pressure profile accordingly. The technology process avoids continuous influx of formation fluids to the surface. Any incidental flow will be contained safely by use of an appropriate process.

The MPD process uses tools and techniques that may mitigate the risks and costs associated with drilling wells that have narrowed, downhole environmental limits, by managing the annular hydraulic pressure profile proactively. MPD may include control of backpressure, fluid density, fluid rheology, annular fluid level, circulating friction and hole geometry, or combinations of all of them. MPD may enable faster corrective action to deal with observed pressure variations. Controlling annular pressures dynamically facilitates drilling of what would be economically unattainable prospects.

Overbalanced drilling (OBD) has been the method of choice for most wells drilled since the early 20th century. The drawback is its dependency on multiple casing strings to prevent fluid loss, due to density increases, and as ECD approaches formation fracture initiation pressure. In ultra-deep water, pore pressures may be high, relative to formation strength, even in shallower depths. This results in numerous casings before reaching the target formation. Thus, the diameter through the producing formation is too small to accommodate production casing and tubing, to produce economic volumes of hydrocarbons.

Mud filtrate and solids can be an issue, along with potential differential sticking of the drillstring. Maintaining ECD below fracture gradients in horizontal sections can also be an issue. Managing drilling fluid properties, flowrates and penetration rates is being implemented. A micronized weighting fluid has been developed, with particles 10 times smaller than conventional barite. The MPD technique is a closed system approach, compared to conventional open systems.

The FPWD tool provides direct, real-time measurement of formation pressure and mobility.



The FPWD tool provides direct, real-time measurement of formation pressure and mobility. The tool is a probe-type formation tester, similar in design and operation to conventional wireline formation testers. Use of the FPWD tool controls the pre-test, to provide the correct rate and volume to yield a stable pressure. The parameters of the pre-test may be either fixed or downhole-variable. Taking pre-tests for drilling applications, such as a pore pressure calibration, can be challenging, given the very dynamic nature of the wellbore and near-wellbore formation, shortly after drilling that section. Lack of mud cake seal can cause supercharging, which can lead to non-representative formation pressures, and continuous invasion and secondary supercharging from mud circulation during the pre-test. This needs to be observed.

Use of the data obtained with the FPWD and MPD technologies needs to be carried through to the completion phase, commencing with installation of the casing strings, along with the cementing design and installation procedure, through to the completion of the producing reservoir.

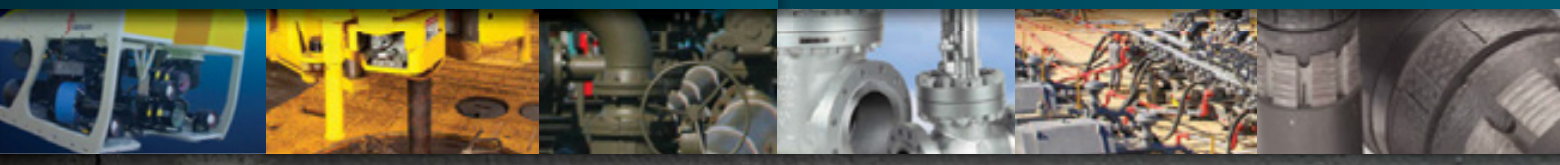
MPD development and practice, and the equipment required to execute it, have been demonstrated in wells in Australia and the U.S., in mature fields and in HPHT environments. WO

■ RVERNOTZY@ROCKWELLENTERPRISE.COM / RICHARD VERNOTZY, president of Houston-based Rockwell Enterprises LLC, holds a BS degree in petroleum engineering from University of Louisiana at Lafayette, and is a registered professional engineer. He has 30 years of industry experience, particularly in offshore drilling and production, as well as project management, with major engineering firms and operating companies.

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DR. JACQUES SAPIR, CONTRIBUTING EDITOR, FSU



Sechin's star rises over Rosneft

Igor Sechin's star is rising, indeed. Rosneft's chairman is now one of the most potent, influential men in Russia after President Putin. The gigantic deal that led to Rosneft's absorption of TNK-BP made this company one of *the* most important firms—if not the company—in Russia's oil sector. So, after the appointment of Sechin to the board of directors of RAO-EES, who and what could stop the man?

On the other hand, at the beginning of July, Dmitry Medvedev, the former president turned prime minister, sacked Alexander Popov, the head of Rosnedra, an agency responsible for granting licenses to develop natural resources. Popov worked with Sechin for years, but this is most probably the last bite of a dying tiger, as Medvedev's own position is not well-assured. Most of his power has been transferred to the presidential administration, and he has lost most of his allies since last winter. The probability that he would leave, or be dismissed by next fall, seems pretty high now. Sechin is thus, and without doubt, the most influential of all Putin's allies and quite certainly Russia's new rising star.

Sechin has been pivotal in Rosneft's transformation into not just one of the biggest oil companies, but into a major player in the whole energy market. Through its association with BP, Rosneft gained access to E&P technology, not just in the oil sector, but as regards associated gas, too. Rosneft also gained a very important technology inflow, which would allow it to be a leader in the shale sector, when Russian authorities decide that the time has come for such activity.

Recent developments in the electric power sector, certified by Sechin's nomination, first to the board of directors and then as president of the board at the annual assembly of shareholders on June 25, are but one example of the diversification strategy he has implemented. During this same time period, he has also prepared Rosneft to become an important competitor in the gas sector, and then to become a supplier to RAO. This is proof that Gazprom, the traditional Russian gas monster, is progressively losing its influence. And, once again, one could correlate this loss to the diminishing status of Dmitry Medvedev.

Sechin has understood, too, which responsibilities belong to him. On July 16, while President Putin was closely monitoring the most important exercise ever launched by the Russian armed forces (and in close cooperation with China), he promised to invest $30 billion in Eastern Siberia and Russia's Far East. By doing so, he made Rosneft one of the most important actors in Russian territorial development policy. Quite certainly, this announcement was timed to correspond with negotiations on the tax burden weighing on Russian oil producers. Also quite certainly, this was timed to fit with Putin's plans to develop the Far East.

Nevertheless, Sechin took an important option in a decisively important field. It is also well known that he has, for years, advocated a so-called "Chinese course" for Russia and has strongly favored the Chinese model. This gives even greater weight to the promise of investing $30 billion, a decision that appears to reflect a change in Russian strategy.

Would then, Sechin become Russia's most important man after Putin, mimicking the former *Duc de Rohan* motto, "King I couldn't, Duke I wouldn't, I am Rohan." Sechin's path to supreme power is still undecided. Maybe, he would prefer to stay in the shadows. Or maybe, he would prefer a more tangible position as prime minister, replacing Medvedev and entering the race for Putin's succession. However, his current status depends on two things.

The first item is Rosneft's and, more generally, the oil sector's contribution to Russian modernization and development. Modernization is important to Putin, and the Russian political elite, who are looking at the U.S. and China with a mix of admiration, envy and resentment. Could Rosneft become, both directly (by using advanced E&P technologies) and indirectly (by fostering a large demand in other industries for advanced technologies), one of Russia's engines of innovation and development?

The second item is more subtle. Sechin's ascent must be compatible with others' ambitions. He would be well-advised to remember what happened to Nicolas Fouquet, King Louis XIV's *surintendant aux finances* (equivalent to Minister of Finance and certainly the most powerful man after the king at the beginning of Louis XIV's reign). Fouquet was a man, whose personal motto was "*Where will I ascend*?" His meteoric rise was succeeded by a dramatic fall, as he attracted the jealousy of too many people, including the king. Sechin's future depends on not antagonizing people.

Sechin's path to power is plagued with uncertainties and enemies, but few doubt that he will become an influential leader, and, maybe, a Putin successor. Putin failed, in his previous attempt, to find a successor. He cannot fail the next time, in 2018. After trying different people from the administration, Putin could then choose someone with a good track record, both in the administration and in business. Sechin appears to be a quite viable candidate. WO

Rosneft Chairman Igor Sechin (right) hands a cooperation agreement to Sakhalin Regional Governor Alexander Khoroshavin in October 2012. Photo courtesy of Rosneft.



SAPIR@MSH-PARIS.FR / Jacques Sapir is a professor of economics at the School for Advanced Studies in the Social Sciences (EHESS) in Paris, and at the Higher School of Economics in Moscow. An expert on Russian economic policy, he graduated from the Institute of Political Studies in Paris in 1976, and earned a PhD in economics from EHESS in 1980.

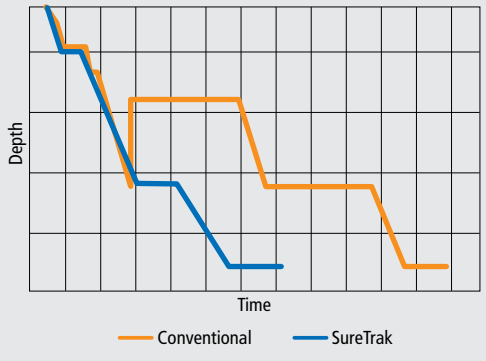


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MELANIE CRUTHIRDS, NEWS EDITOR



Today in Energy

EIA's digital dashboard satisfies curiosity

When the precursor to the U.S. Energy Information Administration (EIA) was established in 1976, people in this country, and elsewhere, lived in an "information-poor world." If you wanted domestic oil production numbers, you might not have known where to look for answers. Even if you did know where to look, you might not have trusted the response you got.

But, that was then. Now we live in an information-rich world, where a single Internet search returns so many millions of "answers" that finding useful, trustworthy information can be daunting. Today, thanks, in part, to the efforts of Charlie Whitmore, the EIA has a powerful information-disseminating tool on its own "Today in Energy" webpage, known as "TIE" for short. While the agency is tasked with collecting, disseminating, evaluating and analyzing energy-related information, TIE gives readers a more, relatable look at the issues.

As a former Federal Energy Regulatory Commission staffer, and senior advisor to the TIE staff, Whitmore said the idea for a more frequently updated source of information within the EIA took form during his interactions with former EIA Administrator Richard Newell. As head of the agency, Newell liked to have a "dashboard" prepared each day for the Secretary of Energy and the White House. As staffers continued to put more into these daily reports, the move to producing longer-form, stories was a natural step. Newell later gave the go-ahead, and, soon, TIE was launched on the front page of the EIA website.

These days, TIE offers a daily stream of topical stories covering a multitude of areas within the energy landscape. What began as a method of recapping data for internal distribution has now become a reference for industry experts who are crunched for time, but would still like to be exposed to things outside their area of specialization.

And, just like the energy industry in which these expert professionals work, things are never stale in the world of TIE. Whitmore said the page often works as a test bed for new ideas, like animated graphics, for the entire digital realm of the EIA.

Recently, said Whitmore, the TIE team has incorporated day-ahead energy pricing information on the page, so that users can compare data all in one place. He added that the successful launch of such projects within the TIE space has demonstrated that the EIA has the potential to play a larger part in the current energy development landscape.

This willingness to test-run new, different concepts has made possible other agency projects, like a proposed rig and well productivity report. The report, which is still in development, would mean that data across all major basins would be collected, and the question of rig count versus productivity could be explored.

Another function poised for expansion is what Whitmore called "response to extraordinary events," in which the agency, on multiple levels, would have the ability to disseminate timely, accurate information to communities experiencing natural disasters like hurricanes, tornadoes, heat waves and cold snaps. The near-real-time release of information, along with more in-depth post-mortems on major events impacting energy, is an ongoing TIE—and EIA—goal.

Whether TIE and the agency are looking to show where energy in the U.S. has been, is going or is currently, Whitmore said the most important thing is a continued sense of curiosity. As long as people want to know more than they do today, there will be a space for TIE and the invaluable information it provides. WO

Members of the Today in Energy team, some of whom are pictured above, cover energy news from sectors such as oil, gas, electricity and renewables. Back row (L-R): David Peterson, Chris Peterson, Michael Ford and Owen Comstock. Front row (L-R): Colleen Blessing, Michael Mobilia, Tom Doggett and Patricia Hutchins.

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U.S. production fell slightly in June, decreasing by 82,000 bopd, mostly in Louisiana, Texas and Alaska. As a whole, world production fell 200,000 bopd, with the greatest declines occurring in Iraq and Norway.

U.S. rotary rig count was down a mere five units to 1,762. Worldwide, however, the number of active rigs increased a healthy 104 units, just barely surpassing last year's June count of 1,510. As has been the trend for the past year, the international offshore rig count remains mostly flat.

Natural gas prices declined to $3.83/Mcf in June, continuing the slow downward trend of the past two months.

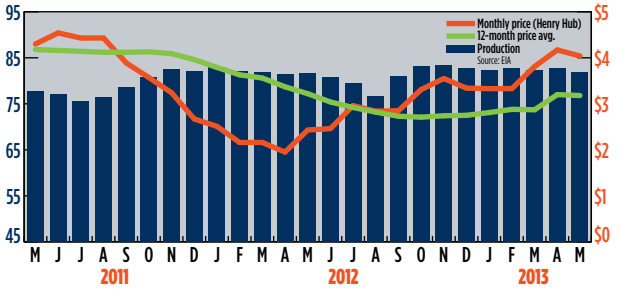
U.S. OIL PRODUCTION[1]

Thousand barrels per day

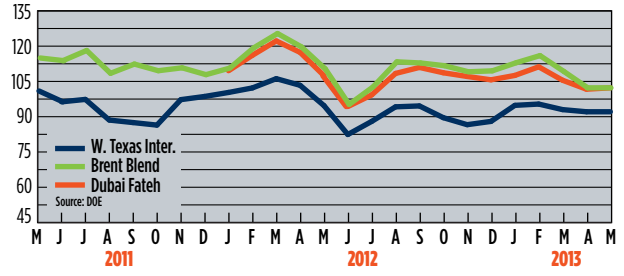
STATE	JUNE 2013[2]	JUNE 2012[3]	% DIFF.	MAY 2013[2]
Alabama	28	25	12.0	29
Alaska	509	493	3.2	545
Arkansas	18	18	0.0	19
California4	580	530	9.4	583
Colorado	145	123	17.9	147
Florida	5	6	–16.7	6
Illinois	27	27	0.0	27
Kansas	128	117	9.4	129
Kentucky	7	7	0.0	7
Louisiana4	1,348	1,400	–3.7	1,399
Michigan	20	19	5.3	21
Mississippi	70	68	2.9	71
Montana	75	64	17.2	75
Nebraska	7	7	0.0	8
New Mexico	280	222	26.1	269
North Dakota	824	660	24.8	810
Ohio	13	13	0.0	13
Oklahoma	302	238	26.9	282
Texas[4]	2,541	1,900	33.7	2,564
Utah	89	78	14.1	90
Wyoming	171	161	6.2	174
Others5	33	31	6.5	34
TOTAL U.S.	**7,220**	**6,207**	**16.3**	**7,302**
LOWER 48	**6,711**	**5,714**	**17.4**	**6,757**

[1] Includes lease condensate.
[2] Preliminary estimate, API.
[3] DOE's revision, as of 10 months from current issue date, adjusted.
[4] Includes federal OCS production.
[5] Includes Arizona, Indiana, Missouri, Nevada, New York, Pennsylvania, South Dakota, Tennessee, Virginia and West Virginia.

U.S. GAS PRICES ($/MCF) & PRODUCTION (BCFD)



SELECTED WORLD OIL PRICES ($/BBL)



WORLD OIL & NGL PRODUCTION

Million barrels per day

	JUNE 2013	MAY 2013	AVG. 2012	AVG. 2011
OPEC–CRUDE OIL[1]				
Saudi Arabia	9.44	9.30	9.51	9.06
Iran	2.70	2.68	3.00	3.62
Iraq	3.05	3.14	2.95	2.67
United Arab Emirates	2.73	2.73	2.65	2.50
Kuwait	2.56	2.58	2.46	2.24
Neutral Zone	0.52	0.52	0.54	0.59
Qatar	0.73	0.73	0.74	0.74
Angola	1.78	1.78	1.78	1.66
Nigeria	1.88	1.96	2.10	2.18
Libya	1.15	1.38	1.39	0.46
Algeria	1.10	1.15	1.17	1.18
Ecuador	0.50	0.50	0.50	0.50
Venezuela	2.48	2.45	2.50	2.50
NGLs & condensate	6.50	6.50	6.33	5.92
TOTAL OPEC	**37.12**	**37.40**	**37.62**	**35.82**
OECD[1]				
U.S.	10.07	10.15	9.17	8.14
Mexico	2.90	2.90	2.92	2.94
Canada	3.70	3.60	3.76	3.53
United Kingdom	0.79	0.88	0.95	1.11
Norway	1.68	1.83	1.91	2.04
Europe-others	0.57	0.60	0.61	0.61
Australia	0.45	0.41	0.48	0.49
Pacific-others	0.08	0.08	0.08	0.09
TOTAL OECD	**20.24**	**20.27**	**19.88**	**18.95**
NON–OECD				
Russia	10.90	10.86	10.73	10.60
FSU-others	2.98	2.82	2.94	2.97
China	4.21	4.29	4.18	4.10
Malaysia	0.69	0.69	0.67	0.65
India	0.93	0.88	0.91	0.91
Indonesia	0.82	0.84	0.89	0.93
Asia-others	1.14	1.12	1.12	1.09
Europe	0.14	0.13	0.14	0.14
Brazil	2.13	2.09	2.16	2.20
Argentina	0.61	0.62	0.67	0.69
Colombia	0.98	1.02	0.95	0.92
Latin America-others	0.42	0.42	0.42	0.43
Oman	0.95	0.96	0.92	0.89
Syria	0.09	0.09	0.16	0.33
Yemen	0.15	0.10	0.18	0.23
Egypt	0.71	0.72	0.73	0.74
Gabon	0.25	0.23	0.25	0.25
Africa/Middle East-others	1.62	1.59	1.52	1.61
TOTAL NON–OECD	**29.72**	**29.47**	**29.54**	**29.68**
PROCESSING GAINS[2]	**2.15**	**2.15**	**2.14**	**2.11**
TOTAL SUPPLY	**89.23**	**89.29**	**89.18**	**86.56**

Source: International Energy Agency Note: Totals and subtotals may not add, due to rounding.
[1] Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
[2] Net of volumetric gains and losses in refining (excludes net gain/loss in China and non-OECD Europe) and marine transportation losses.

U.S. ONSHORE WELL COUNT

Basin	Q2 2013	+/–	Q1 2013	+/–	Year Ago
Ardmore Woodford	45	–4	49	10	35
Arkoma Woodford	5	–8	13	–27	32
Barnett	407	–36	443	–135	542
Cana Woodford	92	10	82	–7	99
DJ–Niobrara	293	27	266	–104	397
Eagle Ford	1,050	5	1,044	118	932
Fayetteville	190	33	157	11	179
Granite Wash	153	12	141	–25	178
Haynesville	112	3	109	3	109
Marcellus	448	–27	475	–71	519
Mississippian	317	–26	343	13	304
Permian	2,294	126	2,169	–203	2,497
Utica	160	29	131	70	90
Williston	609	27	582	42	567
Others	2,624	94	2,530	–478	3,102
TOTALS	**8,800**	**266**	**8,534**	**-782**	**9,582**

Source: Baker Hughes

JOHN.BETZ@WORLDOIL.COM

INTERNATIONAL ROTARY RIG COUNT

Monthly average

REGION & COUNTRY	JUN 2013 Land	JUN 2013 Offshore	MAY 2013 Land	MAY 2013 Offshore	JUN 2012 Land	JUN 2012 Offshore
CANADA	**181**	**1**	**125**	**2**	**223**	**3**
EUROPE	**87**	**51**	**78**	**47**	**70**	**44**
Germany	5	0	5	0	6	0
Italy	4	1	3	2	2	1
Netherlands	4	5	4	3	2	4
Norway	0	19	0	19	0	17
Poland	5	0	3	0	7	0
Romania	8	0	8	0	9	0
Turkey	32	0	29	0	25	1
United Kingdom	0	18	0	14	1	17
Others	29	8	26	9	18	4
MIDDLE EAST	**346**	**43**	**318**	**44**	**349**	**51**
Abu Dhabi	19	7	19	8	14	10
Egypt	52	11	47	11	59	13
Iraq	89	0	80	0	79	0
Kuwait	34	0	30	0	35	0
Oman	48	1	45	1	50	1
Pakistan	24	0	21	0	11	0
Saudi Arabia	64	18	64	19	64	20
Syria	0	0	0	0	27	0
Others	16	6	12	5	10	7
AFRICA	93	40	87	37	69	37
Algeria	48	0	46	0	41	0
Angola	0	13	0	11	1	11
Kenya	5	0	2	0	2	0
Libya	14	1	15	0	10	0
Nigeria	10	10	11	11	4	15
Others	16	16	13	15	11	11
LATIN AMERICA	**328**	**95**	**330**	**94**	**352**	**83**
Argentina	81	0	85	0	70	0
Brazil	17	44	20	42	50	41
Colombia	45	0	44	0	44	0
Ecuador	26	2	25	2	14	0
Mexico	59	40	69	41	84	29
Venezuela	81	6	71	7	70	9
Others	19	3	16	2	20	4
ASIA-PACIFIC	**142**	**108**	**143**	**106**	**139**	**90**
Australia	11	8	12	8	12	8
China, offshore	0	20	0	18	0	13
India	84	35	83	35	85	26
Indonesia	27	9	28	11	27	9
Malaysia	0	11	0	10	0	12
New Zealand	5	1	7	1	5	0
Thailand	5	16	4	15	5	12
Vietnam	0	3	0	3	0	6
Others	10	5	9	5	5	4
TOTAL	**1,177**	**338**	**1,081**	**330**	**1,202**	**308**

Source: Baker Hughes
Note: Totals may not add, due to rounding.

*No data available for Iran and Sudan/South Sudan.

INTERNATIONAL OFFSHORE RIGS

JUNE 2013	U.S. GULF OF MEXICO Mobile	U.S. GULF OF MEXICO Platform*	EUROPE/MEDITERRANEAN Mobile	EUROPE/MEDITERRANEAN Platform*	WORLDWIDE Mobile	WORLDWIDE Platform*
Total rigs in fleet	110	54	120	105	852	299
year ago	114	52	119	105	829	298
Contracted rigs,	78	29	113	101	725	254
year ago	76	27	108	102	685	253
Rig utilization, %,	70.9	53.7	94.2	96.2	85.1	84.9
year ago	66.7	51.9	90.8	97.1	82.6	84.9

Source: Offshore Data Services' Weekly Mobile Offshore Rig Count

*Updated quarterly.

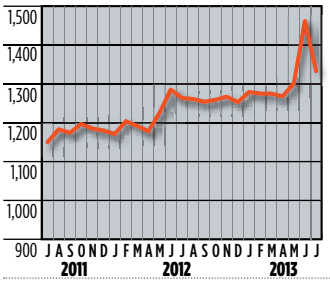
WORKOVER RIG COUNT

REGION	JUNE 2013	MAY 2013	APRIL 2013	JUNE 2012	% chng mo. ago	% chng yr. ago
Texas Gulf Coast	206	258	197	229	-20.2	-10.0
ArkLaTex	133	140	138	132	-5.0	0.8
Eastern U.S.	88	92	92	96	-4.3	-8.3
South Louisiana	22	20	27	29	10.0	-24.1
Mid-Continent	212	215	213	232	-1.4	-8.6
West Texas / Permian	697	673	678	716	3.6	-2.7
Rocky Mountains	357	360	353	348	-0.8	2.6
West Coast / Alaska	334	341	341	357	-2.1	-6.4
TOTAL U.S.	**2,049**	**2,099**	**2,039**	**2,139**	**-2.4**	**-4.2**
CANADA	**506**	**447**	**429**	**671**	**13.2**	**-24.6**

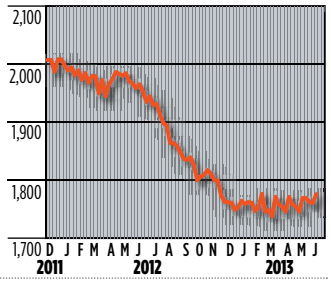
Source: Cameron

Note: Totals may not add, due to rounding.

INTERNATIONAL ROTARY DRILLING RIGS



U.S. ROTARY DRILLING RIGS



Source: Baker Hughes

U.S. ROTARY RIG COUNT

Monthly average

STATE & AREA	JUNE 2013	MAY 2013	JUNE 2012	% DIFF. JUNE '12 JUNE '13
ALABAMA-TOTAL	**7**	**6**	**7**	**0.0**
Land	7	6	7	0.0
Inland water	0	0	0	0.0
Offshore	0	0	0	0.0
ALASKA-TOTAL	**8**	**8**	**7**	**14.3**
Land	7	7	6	16.7
Offshore	1	1	1	0.0
ARKANSAS	**14**	**14**	**20**	**-30.0**
CALIFORNIA-TOTAL	**38**	**41**	**54**	**-29.6**
Land	36	39	52	-30.8
Offshore	1	2	2	-50.0
COLORADO	**62**	**61**	**69**	**-10.1**
FLORIDA	**1**	**1**	**1**	**0.0**
KANSAS	**28**	**27**	**28**	**0.0**
KENTUCKY	**1**	**1**	**4**	**-75.0**
LOUISIANA-TOTAL	**106**	**107**	**124**	**-14.5**
North - Land	23	21	31	-25.8
South - Inl. water	22	24	19	15.8
South - Land	17	18	29	-41.4
Offshore	45	44	46	-2.2
MICHIGAN	**1**	**1**	**1**	**0.0**
MISSISSIPPI	**10**	**12**	**3**	**233.3**
MONTANA	**10**	**10**	**21**	**-52.4**
NEBRASKA	**1**	**1**	**1**	**0.0**
NEVADA	**3**	**4**	**2**	**50.0**
NEW MEXICO	**76**	**76**	**87**	**-12.6**
NEW YORK	**0**	**0**	**0**	**0.0**
NORTH DAKOTA	**177**	**176**	**200**	**-11.5**
OHIO	**32**	**32**	**20**	**58.8**
OKLAHOMA	**179**	**188**	**193**	**-7.1**
PENNSYLVANIA	**54**	**58**	**82**	**-34.1**
SOUTH DAKOTA	**2**	**1**	**1**	**75.0**
TENNESSEE	**0**	**0**	**0**	**0.0**
TEXAS-TOTAL	**841**	**838**	**932**	**-9.7**
Offshore	8	5	1	700.0
Inland water	1	1	1	0.0
District 1	139	136	144	-3.5
District 2	84	87	92	-8.7
District 3	47	47	44	6.8
District 4	32	35	41	-22.0
District 5	13	13	19	-31.6
District 6	26	26	33	-21.2
District 7B	13	13	13	0.0
District 7C	81	82	87	-6.9
District 8	281	278	318	-11.6
District 8A	35	36	37	-5.4
District 9	21	22	26	-19.2
District 10	62	60	76	-18.4
UTAH	**34**	**31**	**39**	**-12.8**
W. VIRGINIA	**23**	**23**	**25**	**-8.0**
WYOMING	**47**	**43**	**40**	**17.5**
OTHERS	**7**	**7**	**6**	**16.7**
U.S. OFFSHORE TOTAL	**55**	**52**	**50**	**10.0**
U.S. GRAND TOTAL	**1,762**	**1,767**	**1,967**	**-10.4**

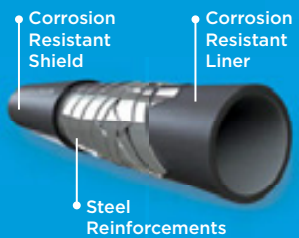
Source: Baker Hughes

Note: State monthly averages may not add up to U.S. total, due to rounding.

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Brittle failures of OCTG components due to improper testing after manufacturing



Improper test methods, used after component manufacture, may lead to catastrophic brittle failures during service. Material testing should be performed on the test specimens taken from the heat treated raw bar and at the critical section of the component.

SRINIVASA KONETI, JOHN ROSS and SAMIT GOKHALE,
T H Hill Associates

Brittle cracking of oilfield tubular components can occur, due to poor fracture toughness of the material. For heat-treated material, most vendor and user manufacturing specifications, including those from the American Petroleum Institute (API), require the mechanical test specimen to be removed from either a sacrificial production part, a prolongation removed from a production part, or a QTC from the same heat.

Testing of OCTG components requires careful attention to specimen selection, to avoid possible brittle cracking. The specimen should be taken from either a sacrificial production part, a prolongation removed from a production part, or from a Quality Test Coupon (QTC) from the same heat, that is correctly sized.

In certain cases, manufacturers prefer to perform all mechanical testing on a QTC. Improper testing methods used after manufacturing, including improper QTC testing, may lead to catastrophic, brittle failures.

This article presents case studies, which show that the material test results obtained on the QTC, especially Charpy V-notch (CVN) impact energy values (pointing to the fracture toughness of the material), varied significantly from the material properties of the actual component. If the testing had more accurately reflected the material properties of the actual component, it would not have been put in service and would not have failed. The article also discusses the testing locations on larger-diameter components, apart from appropriate, representative testing methods. The mechanical properties of larger-OD components vary significantly from the OD to the ID of the component. The article provides procedures for testing at appropriate locations to get the actual mechanical properties at critical sections in the finished component.

CASE STUDIES

Case 1 (C1) is a mandrel hanger failure. It was reported that the string was picked up, after making up the mandrel hanger and pup joint with the casing running tool. When the string weight was on the mandrel hanger tool, a loud sound was heard. Lifting was stopped, and the casing was examined, where it was observed that a huge longitudinal crack had formed on the mandrel hanger box connection, Fig 1.

Fig. 1. Overall view of the C1 longitudinal crack.



Fig. 2. Overall view of the C2 pin failure.



The failed mandrel hanger was sent to T H Hill Associates (THHA) to determine the root cause of the failure.

Case 2 (C2) is a BOP wear bushing running tool failure. The pin connection of the tool twisted-off, while making up with the drill collar box connection. Based on a visual examination of the fracture surface, the failure mechanism was identified as a brittle fracture with rapid crack propagation, **Fig. 2.** To confirm the cause of the failure, the failed wear bushing running tool was sent to THHA for further investigation.

Case 3 (C3) is a saver sub, which had no physical failure. A review of material test reports was requested by an operator for a 12-in. OD top drive saver sub (NC77 box x 6⅝ FH pin) as part of a fit-for-purpose evaluation associated with a deepwater landing string analysis. The material testing was performed at 1 in. below the OD of the bar stock, which was not the critical

Fig. 3. Saver sub (C3) as received for testing.



Fig. 4. Overall view of the fracture surface on C1.



section of the saver sub. A representative saver sub was sent to THHA, to determine the material properties at the critical section of the saver sub, **Fig. 3.**

Visual examination

The C1 and C2 fracture surfaces were examined visually to identify signatures on the fracture surface to help determine the fracture mechanism. The overall appearance of the fracture surfaces was flat and exhibited a grainy texture, **Figs. 4** and **5**. This is typical morphology for brittle cracking.

SEM analysis

The C1 and C2 fracture surfaces were observed, using a scanning electron microscope (SEM). The fracture examination revealed transgranular features (**Figs. 6** and **7**), which are typical of a brittle fracture. This examination confirmed that the failures were caused by brittle cracking.

Material testing

Material testing was performed on the C1 and C2, to compare the tested results with Material Test Reports (MTRs) and to determine if poor material properties contributed to failures. Material testing was also performed in the critical section and 1 in. below the surface of the top drive saver sub (C3). **Tables 1** and **2** present the test results obtained on the components. The material properties obtained on the failed mandrel hanger, wear bushing running tool and the saver sub (obtained at the critical section) varied significantly from those listed in the MTR.

C1: Mandrel hanger. Upon review of the MTR, THHA determined that the mandrel hanger was machined from a heat-treated raw bar of 14.23-in. diameter by 160-in. length. A QTC of 4-in. H x 4-in. W x 8-in. L size (meeting PSL 3 and PSL 4 requirements from API Spec. 6A) was also heat-treated, along

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with the raw bar, to represent the material properties of the raw bar. All the material testing was performed on the QTC, instead of the raw bar. The variation in properties between QTC and hanger can be attributed to the difference in the thickness of the raw bar to the thickness of the QTC. The Charpy results obtained on the failed sample were very low and also showed a huge variation from the MTR values. Impact toughness correlates well with fracture toughness of the steel. Low-fracture toughness makes the material notch sensitive and typically results in a predominately brittle fracture [Hill, T.H.: Drill String Design and Failure Prevention], as was seen in the failure itself.

C2: Wear bushing running tool. Similar to C1, the wear bushing running tool was machined from a heat-treated raw bar of 18-in. diameter. Along with the raw bar, a QTC of size 4-in. H x 4-in. W x 6-in. L (which meets PSL 3 and PSL 4 requirements from API Spec. 6A) was also heat-treated to reflect the material properties of the raw bar. The material testing results, obtained on the QTC, varied significantly from the mechanical testing results obtained on the failed component. This variation in mechanical properties can be attributed to the difference in the thickness of the raw bar (18-in. diameter) to the thickness of the QTC (4-in.).

C3: Top drive saver sub. For the sub, Fig. 8 shows the pin size relative to the body. The sub had a 12-in. OD with a 4-in. ID. Mechanical testing was performed at 1 in. below the body surface and at the critical section (near pin neck) of the saver sub to evaluate the sub's properties against API Specification 7-1 material testing requirements, and to compare against MTR values, Table 2.

The results obtained from 1 in. below the surface met API Specification 7-1 for strength and Charpy V-notch Impact En-

Fig. 5. Overall view of the C2 fracture surface.



Fig. 6. C1 fracture surface, as seen under SEM.

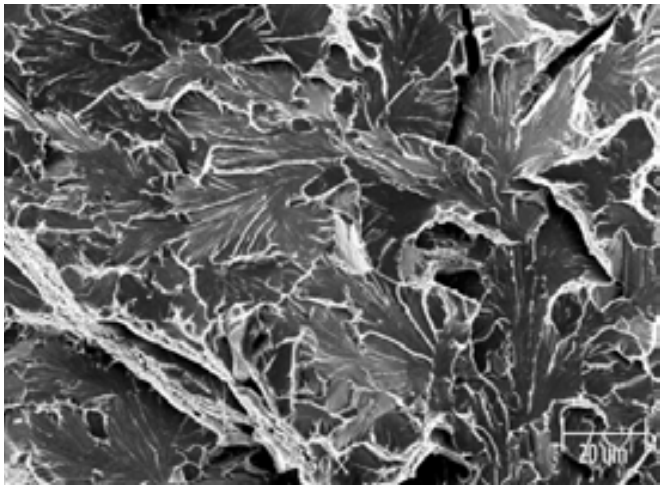


Fig. 7. C2 fracture surface, as seen under SEM.

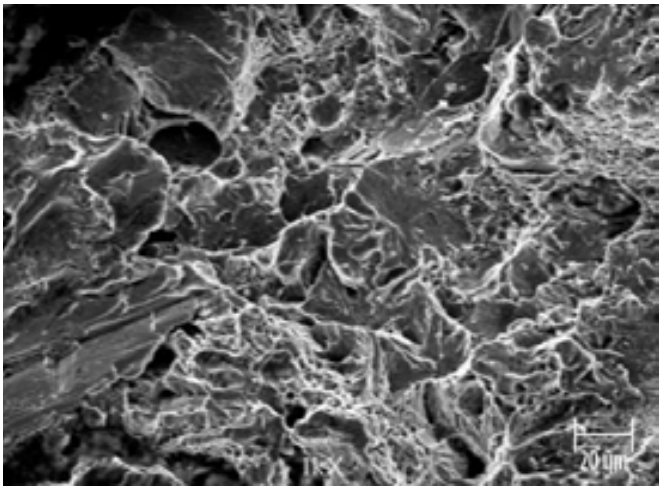


Fig. 8. Saver sub 6⅝ FH pin and body size.

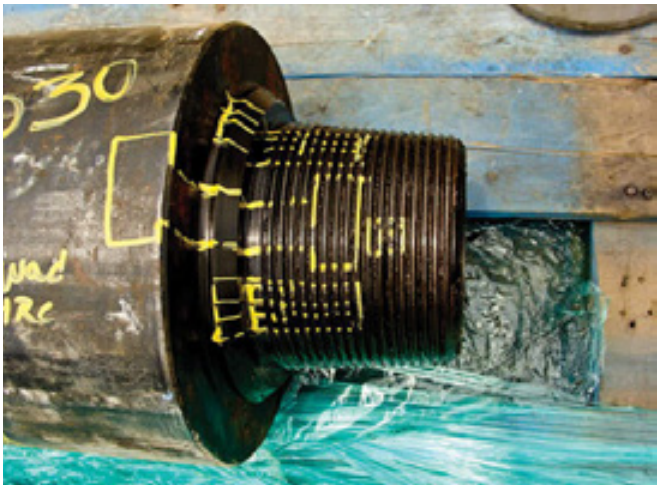


Table 1. Material properties obtained on C1 and C2.

	Yield strength, ksi	Tensile strength, ksi	Elongation, %	CVN Single reading, ft-lb	CVN Average value, ft-lb
C1: MTR values	78.1	112.8	22.5	52, 39, 62	51
C1 : Mandrel hanger	92.4	103.9	21.9	6, 7 , 7	7
C2: MTR values	184.9	197.2	12.0	21, 19, 22	21
C2: Wear bushing running tool values	201.0	213.0	15.6	10, 10, 10	10



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Table 2. Material properties obtained on C3.

Requirements, results	Specimen testing location	Tensile test (0.2% offset method)			Charpy V-notch impact energy @ 70°F test temperature	
		Yield strength, ksi	Tensile strength, ksi	Percent elongation, %	Single reading, ft-lb	Average value, ft-lb
API Spec. 7-1, drill-stem subs	1-in. below OD	100 (min)	135 (min)	13, min.	35, mi.	40 (min)
MTR values	1-in. below OD	128.6	152.2	16	50, 41, 51	47
Saver sub(C3)	1-in. below OD	128.7	153.5	17.4	44, 45, 45	44
	Near pin neck (critical region)	111.8	139.4	16.9	18, 19, 20	19

ergy (CVN). However, the Charpy impact values obtained near the pin neck critical section did not meet the minimum CVN requirements. The reason for the low CVN values is likely associated with the difficulty of heat treating large-diameter, frequently solid bar stock.

The critical section was found to have significantly low CVN values, which are indicative of brittle material that is sensitive to cracking. This means that typical crack detection inspection intervals may likely be too long to find the cracking prior to failure. Further, failure of this type of component can be very dangerous, as it is overhead in the top drive section and sees the highest loads in the string.

QTC SELECTION

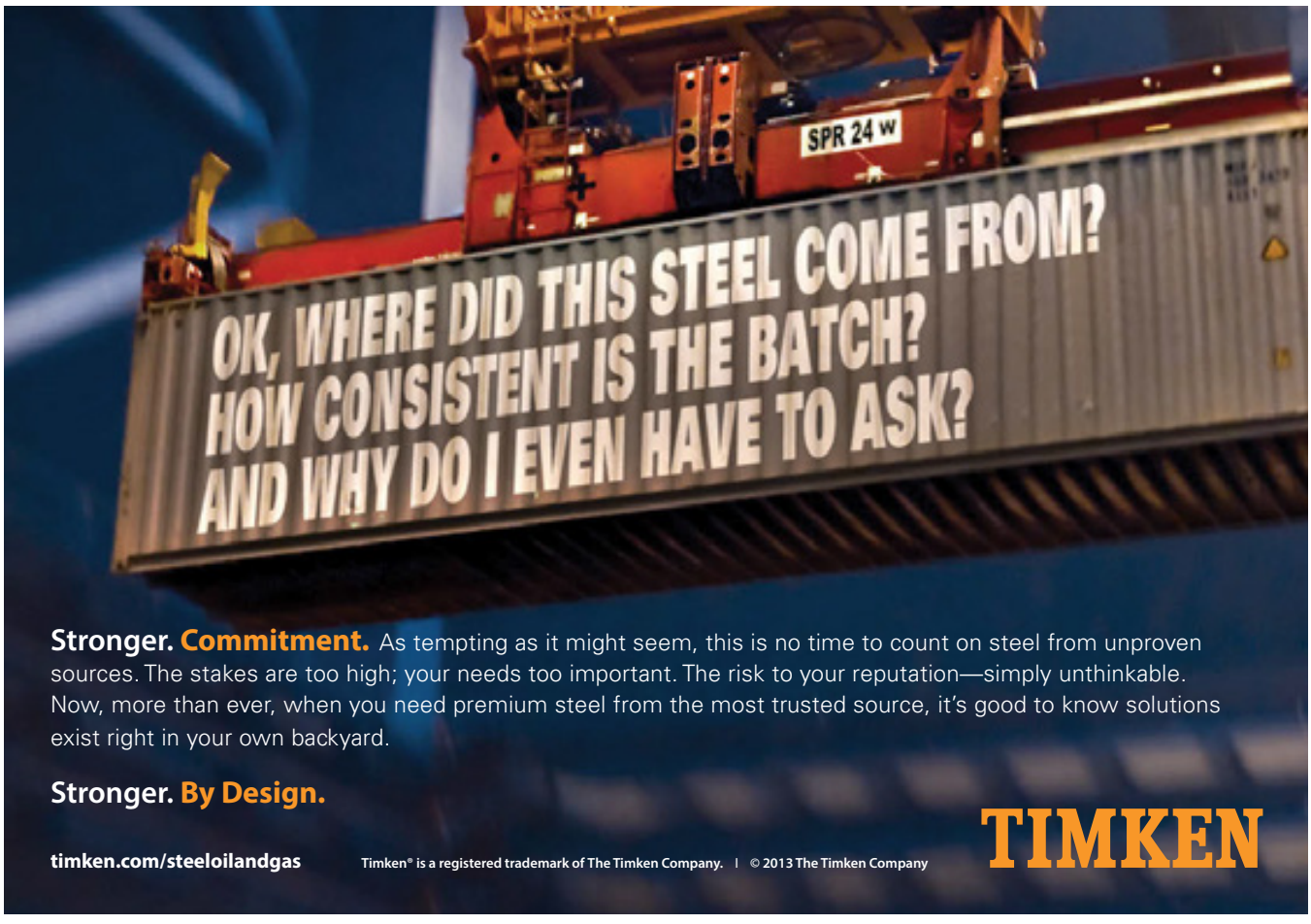
Equivalent Round (ER) methods, as specified in API Specification 6A (twentieth edition) section 5.7.2 and API Specification 7-1, Annex C, C.5.3.1, are used to determine the size of a QTC. The ER of a part is determined using the actual dimensions of the part in the "as heat-treated" condition. The ER of the QTC must be equal to, or greater than, the ER of the part it qualifies, except as follows (API Spec. 6A):

For Product Specification Level (PSL) 2:

1. Forging: size not required to exceed 2½ in. ER
2. Casting: size not required to exceed size shown in ASTM A703/A703M

For PSL 3 and PSL 4: size not required to exceed 5 in. ER.

API 7-1, Annex C has no QTC requirements for PSL 2, and above, for drilling components. In several cases, manufacturers prefer to select the QTC size, based on PSL 3 and 4 requirements from specification 6A, which are intended to be more stringent for wellhead components. However, the limited ER is only meant to apply to wellhead and Christmas tree equipment



(the scope of 6A). If ER methods are used on drilling components, there is no reason to limit the ER value at all.

CONCLUSIONS

Improper test methods used after component manufacture, such as QTC testing, may lead to catastrophic brittle failures during service. Material testing should be performed on test specimens that are taken from either a sacrificial production part, a prolongation removed from a production part, or from a QTC from the same heat that is correctly sized.

In some cases, the manufacturers prefer to perform all mechanical testing on a QTC, instead of an actual heat-treated raw bar. However, case studies C1 and C2 indicate that material test results obtained on the QTC, especially Charpy V-notch impact energy values, which point to the fracture toughness of the material, often do not accurately represent the material properties of the actual component. Using prolongations or sacrificial components are preferred, since they tend to more accurately represent the machined component material properties. Even following the QTC requirements to API 7-1, Annex C will more accurately represent the actual raw bar properties as API 7-1, Annex C has no limits on QTC requirements.

C3 showed that the testing performed at 1 in. below the surface is also not desired for large-diameter bar stock that has smaller critical sections. Additional testing at mid-wall should be performed to evaluate the critical section of the component. The best way to evaluate the material properties is to perform the testing at the critical section (near pin neck). WO

ACKNOWLEDGMENT

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SRINIVASA KONETI is a senior failure analyst and materials engineer at T H Hill Associates. He has been with the company since 2008 and has worked on numerous failure analysis projects for major and independent operators in oil and gas regions of the world. He also manages the failure analysis and materials engineering consulting work by delegating and overseeing the projects. He holds an MS degree in material science engineering from Florida International University.



JOHN ROSS has been a drilling and completion project consultant at T H Hill Associates since 2008. He has provided engineering support for an array of projects, including deepwater landing string analysis, failure investigation, mechanical design review and drill string design. He holds a BS degree in both mechanical engineering and aerospace engineering from the University of Florida.



SAMIT GOKHALE, vice-president of engineering at T H Hill Associates, has been with the company since 2001. He manages all engineering projects and is an instructor for drillstring design and failure prevention courses. He also provides expert witness support for investigations that lead to litigation. He holds a MS degree in mechanical engineering from the University of Florida.

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Many times, a well that must be hydraulically fractured to be economic will experience a production decline that will make attaining the well's estimated ultimate recovery (EUR) impossible. In unconventional reservoirs, such as shales with long laterals requiring multiple frac stages, it is often more economical to refracture the same lateral wellbore, rather than to drill a new well. In shale reservoirs, it is common to shoot 1-to-3-ft perforation clusters, with four to six phased shots per ft (13 to 20 shots per m), with clusters spaced greater than 50 ft (15.2 m) apart.

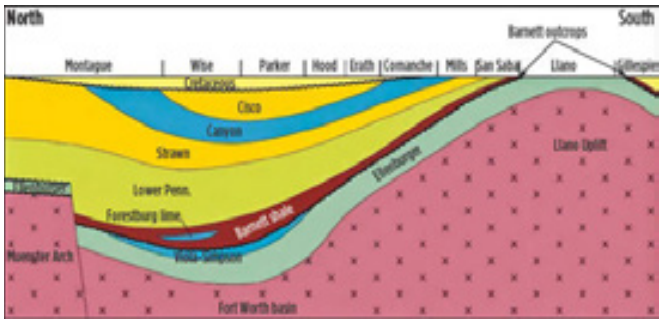
To effectively refracture the well, it is desirable to at least restimulate all the old perforations, but it is preferable to seal them off, and shoot new perforation clusters between them, especially for widely spaced perf clusters. A common way of doing this is to squeeze off all the old perforations with cement, drill out the cement from the wellbore, and conduct a standard plug-and-perf frac treatment from the toe to the heel of the well, perforating between the old perforations. This may work, assuming the cemented perforations, especially near the heel of the well where frac pressures are highest, hold up.

Other methods of refracturing use diverters, such as 100 mesh sand, rock salt, perforation ball sealers, benzoic acid flakes and biodegradable particulates.[1] These are designed to plug the perforations, taking the most flow, thereby diverting flow to other perforations to get a more uniform injection of fracturing fluid and proppant along the lateral. These are also designed to unplug the perforations during flowback, to allow production from all the perforations.

Refracturing has been done in shale oil wells with uncemented liners, using methods that include the "pump-and-pray" method, where fracturing fluid slurry is bullheaded into the formation through the perforations or fracports. Wells initially fractured using this method are thought to be good candidates for refracs, which would imply they were understimulated initially.[2] It is interesting, however, that, anecdotally, at least one operator has also had successful refracs using this method in the Bakken.

The other extreme is the use of mechanical isolation, such as a liner and packers placed in the well at locations to provide isolation for each frac stage from the old perforations uphole.

Fig. 1. Cross-section of the Fort Worth basin in North-Central Texas showing the Barnett shale.[6]



However, this method using conventional packers and liners can severely reduce the effective ID of the wellbore available for refracturing operations.[3]

For instance, for the refrac in a 5½-in., 17-lb/ft casing with an ID of 4.892-in., the use of a 3½-in. conventional liner with swellable elastomers would result in an available drift of 2.992 in., compared with a post-expanded drift of 4.151 in., when using the expandable 4¼-in. liner. The solid-steel expandable liner would give ample room to run the large guns necessary for perforating two strings, as well as the coiled tubing for drilling out the frac plugs.

BARNETT SHALE BACKGROUND

The Barnett is one of the largest shale gas plays in the U.S., with 43 Tcf of technically recoverable gas reserves, of which about 7 Tcf have been recovered as of 2010.[4, 5] Annual production was about 0.7 Tcf by 2010. However, with the drop in gas prices after 2007, gas production is expected to level off, or fall, as operators stop drilling new gas wells and even shut in existing wells. The Barnett was a game-changing shale gas development in the U.S., where Mitchell Energy and Development experimented during the 1980s and 1990s, to commercialize shale gas production in North-Central Texas.

The technology developed was the advent of multi-staged fracturing treatments of predominately horizontal wells, which created hydraulic fractures running perpendicular to the lateral wellbore. In the Barnett, laterals range in length from 2,500 to 3,500 ft, although lengths as long as 5,000 ft have been drilled. Barnett laterals are usually cased and cemented using 5½-in. casing, and hydraulically fractured using the plug-and-perf method, with multiple frac stages. Each frac stage is perforated with multiple perforation clusters where fractures are initiated. Over time, spacing of hydraulic fractures has become smaller, and, today, the spacing of hydraulic fractures, or perforation clusters, is usually as narrow as 50 ft.

Barnett wells have been fractured with either cross-linked gels, to get wider fractures and to carry more proppant (100 mesh to 20/40 mesh sand), or with water containing drag-reducing additives (slick water), to allow high pumping rates to better enable proppant transport, and to encourage multiple fracture development. Presently, slick water is used more in shale gas plays, while cross-linked gels are used more in shale oil plays. A typical slickwater frac in the Barnett shale consists of 500,000 to 6 million gal of fluid, 80,000 to 1.0 million lb of sand, and pumps at rates of 50 to 100 bbl/min.[6] Greater quantities of fluid and proppant are used in horizontal Barnett wells, as opposed to vertical Barnett wells.

Figure 1 shows the location of the Barnett shale in the Fort Worth basin and its neighboring stratigraphy. Fracture barriers are necessary in the Barnett shale, to control fracture height, so that fracture network creation will be maximized and the induced fractures will be kept from intersecting any nearby water-bearing unit, such as the Ellenburger formation. Water encroachment into the Barnett from the underlying Ellenburger can be a significant problem. The Viola-Simpson limestone formation that lies between the Barnett and the Ellenburger helps to provide a barrier to the downward growth of hydraulic fractures.[6]

Initial production of a Barnett horizontal gas well typically ranges from 1.6 MMcfgd to 2.5 MMcfgd, with well EUR of 2.4 Bcf to 3.5 Bcf. Declines in production can be 50% to 55% during the first year for a Barnett horizontal well.[6] When determining good well candidates for refracturing, one should consider other factors outside of production decline. Reservoir quality and completions effectiveness, including the azimuth of the fracture, should also be considered.[2, 7]

In the Barnett shale, refracs have been successful, especially when wells that were originally fractured with gelled fluids or foams have been refractured with slick water. This was demonstrated in the second refrac of the Mitchell Energy "discovery" shale well using slick water, where the initial post-refrac production was triple that of the initial frac using foam and the first refrac using gelled fluid.[8] This is attributed to the slick water bypassing polymer damage, opening smaller fractures than gelled fluid could, and extending the fracture system more, because of the larger quantities of slick water used.[8] When new areas in the shale are exposed by a refrac, especially if re-perforated in new locations in the lateral, there should also be a gain in reserves.

SOLID EXPANDABLE TECHNOLOGY

There are several commercial processes for expanding solid-steel liner downhole for wellbore repair and perforation isolation.[9] All of these use some form of hydraulic pressure and/or mechanical force to expand the liner, and/or sealing elements downhole at in-situ temperature and hydrostatic pressure conditions. The process used in this work is a hydraulically-pressured, cone-driven expansion assisted by mechanical pull from the inner string running from the rig floor to the top of the cone, as shown in **Fig. 2.** Clean fluid pumped behind the cone through the innerstring exerts hydraulic pressure behind the cone, which is machined using specially formulated, hardened steel. In addition, pull applied to the innerstring can increase the force available for the expansion. When the net stress applied to the liner exceeds its yield stress, the liner will start deforming in the plastic region of the stress-stain envelope, in a cold-working manner. The cone angle and size is designed such that the total deformation of the liner does not exceed the strain that creates the ultimate stress necessary for the material to fail. The liner strength actually increases during expansion, although the remaining ductility is reduced.

The tubing used for expandable liners is manufactured using electric resistance welding (ERW) and a special quality steel. This steel is designed to match the strength properties of L-80 steel, with enhanced expansion properties. For refracturing purposes, the usual sizes are 4¼ in. for use in 5½-in. base casing, and 5½ in. for use in 7-in. base casing. For higher pressure and



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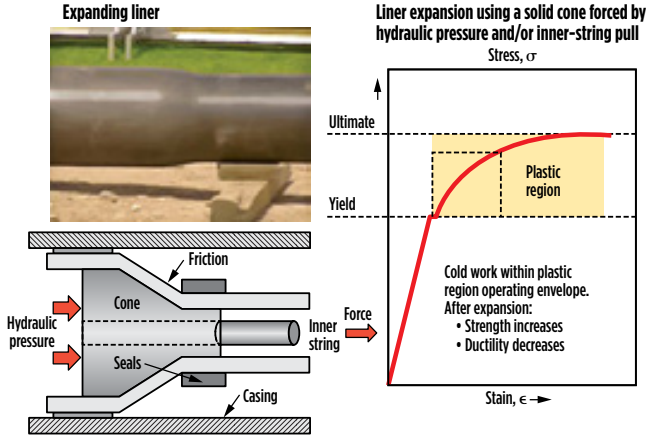
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Fig. 2. Cone-driven expansion using hydraulic pressure and/or inner-string pull.



temperature applications, and for the smallest size base casing, 4½ in., special partially expandable systems or single-joint liners, where connections do not have to be expanded, have been designed using 110-ksi-rated materials. This article considers the application of refrac liners for the Barnett shale and other shale formations, where temperatures and refrac pressures are moderate enough to allow the use of liner with strength properties comparable to L-80, as well as connections with standard tensile loading ratings.

Table 1. Dimensions and properties of the expandable 4¼-in. liner.

Pre-expansion specifications		Post-expansion specifications	
Grade	EX-80	Expansion ratio	12.3%
Nominal yield	80,000 psi	Collapse	3,980 psi
Nominal weight	10.70 lb/ft	Nominal weight	11.35 lb/ft
Nominal OD	4.250 in.	Nominal OD	4.688 in.
Nominal ID	3.750 in.	Nominal ID	4.210 in.
Drift ID	3.625 in.	Drift ID	4.151 in.
Wall	0.250 in.	Wall	0.239 in.
Internal yield	8,240 psi	Internal yield	7,348 psi

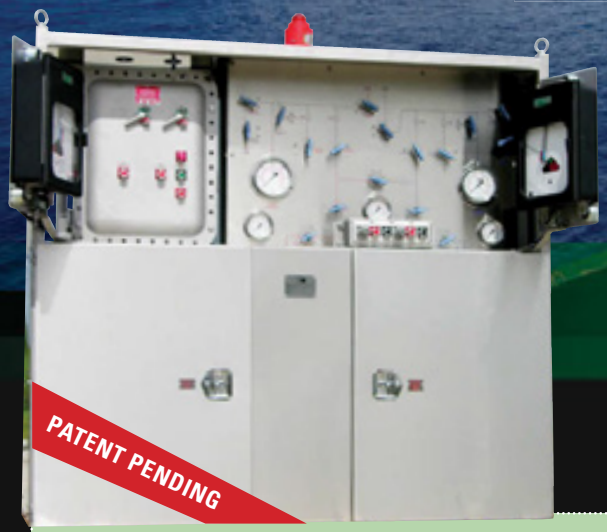
The top photo in Fig. 2 shows a liner in the process of expansion. The amount of increase in ID during expansion varies from 5% to 18%, and depends on the size and weight of the base casing. However, expansions have been done successfully above 20%. Wall thickness decreases during the expansion, usually by less than 4%. During the expansion, the liner also shrinks in length by a small amount, usually less than 5%. The illustration in the lower part of Fig. 2 shows seals, both uncompressed and compressed, after expansion. The compressed seals support the liner in the base casing and provide isolation for frac stages. These also provide isolation from unwanted perforations, as well as from casing damage. Cone expansion takes place at rates from 30 to 15 ft/min, although the effective rate is less when taking into account the time for disconnecting and laying down workstring joints. An internal lubricant is coated on the inner surface of the liner to minimize cone friction during expansion. Sometimes, a secondary lubricant is added to the wellbore fluid,

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to assist in running the expandable liner into the wellbore. A special connection sleeve is installed with each connection, to protect it from being damaged while running in the wellbore. This sleeve is usually 0.04 in. thick, adding 0.08 in. to the OD, which should be less than the drift of the base casing.

This expandable liner process was first successfully implemented in 1998, and it has undergone upgrades and refinements. Presently, solid expandable solutions have been constructed and installed for applications requiring: lengths to 6,935 ft, seals for temperatures to 400°F (with special applications up to 518°F); up to 20 ppg mud weight; installations to depths of 28,750 ft, MD; and installations in wells with inclinations up to 100°.

Description of the well and expandable liner. The refrac liner used in the first case history was installed in the lateral section of a horizontal well in the Barnett shale, referred to here as Well #1. This well has 10,730 ft of 5½-in., 17-lb/ft, N-80 production casing. Well #1 has a total length of approximately 10,800 ft, MD, and a TVD of approximately 7,000 ft. The well was initially completed with perforation clusters in the lateral section from 7,633 to 10,628 ft, spaced about 100 ft apart. The initial fracturing treatment was done in four stages, with total volumes of 32,000 gal of acid and 1.6 million gal of slick water, and 713,000 lb of frac sand.

Fig. 3. Anchor hanger and perf spacing for the refrac of Well #1.

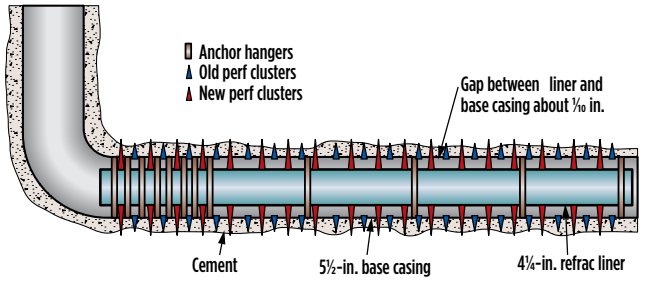
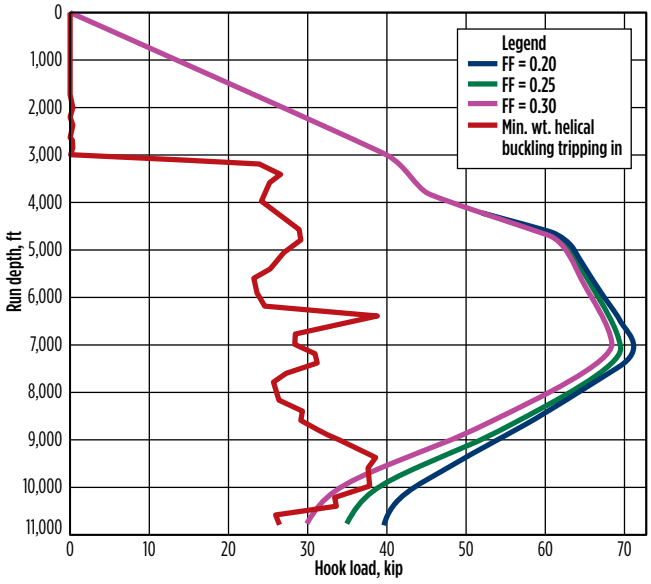


Fig. 4. Torque and drag analysis, showing the impact of friction coefficient on hookload when running the refrac liner assembly downhole.



Well #1 was produced for three years, during which time production dropped from a peak rate of 2.6 MMcfgd to 0.4 MMcfgd, after which the decision was made to re-fracture the well. Mechanical isolation of perforations was designed to be done using approximately 3,244 ft of 4¼-in., L-80-strength expandable liner. Table 1 shows the dimensions and properties of the liner, before and after expansion.

Isolation of stages and frac clusters was done, using joints of this liner with bands of elastomer thermally bonded to the liner surface. These joints are referred to as "anchor hangers," because of their ability to anchor the liner in place, as well as to isolate frac stages and/or perforation clusters. Each of the interior anchor hanger joints contained three bands of elastomer bonded to the surface of the liner, spaced evenly over a 30-ft interval. The interior anchor hangers had an average length of 41 ft, each. The first and last anchor hanger joints were 21 ft long, with five bands of elastomer.

The refrac was planned to occur with an optimized number of stages, with anchor hanger joint spacing designed to demonstrate both stage and perforation isolation. All anchor hanger joints, except for the first and last, were positioned to straddle directly across each perforation cluster. The last perforation cluster at the toe of the well was left open to facilitate the pumping of tools during the refracturing treatment.

The concept for the anchor hanger spacing was that the lower two-thirds section of the refrac liner would have approximately 500-ft spacing between anchor hanger joints, whereas the upper third of the liner would use anchor hanger joints straddled across each existing perf cluster.

After the installation of the refrac liner, new perforation clusters were shot between the old perforation clusters, spaced approximately 100 ft apart. The refrac treatment was done using optimally-positioned frac plugs. Thus, the first stages were over lengths of about 500 ft, in which the interior perf clusters were not isolated by the anchor hangers—only stage isolation was achieved. In the last stage, each of the old perforation clusters was isolated by an anchor hanger. It may be that the small gap of 0.102 in., between the expanded liner with OD of 4.688 in. and base casing with ID of 4.892 in., would be effective in preventing channeling down the annulus to neighboring perforation clusters.

This gap is further reduced at the connections to 0.042 in. because of the presence of the connection sleeves. Fracturing diagnostics, such as downhole microseismic, could be used to tell if fractures were being created uniformly over the stages and whether individual isolation of perforation clusters is necessary. Figure 3 is an approximate illustration, showing spacing of anchor hangers and perforation clusters. Here, the 1/10-in. gap is exaggerated to show how channeling in the annulus could occur, however minimal this may be.

Placing a frac plug above the previous anchor hanger, and within the 500-ft interval of interest, would expose this portion of the refrac liner between the frac plug and the previous anchor hanger to a collapse condition. Sufficient expandable liner was used, such that the end of the post-expanded liner was 100 to 200 ft above the upper-most perforation cluster.

INSTALLATION PROCESS

Engineering provided the specifications of the pre- and post-expanded liner (Table 1), as well as the elastomer specifications. Also calculated were the expected torque and drag

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requirements to avoid buckling and lock-up while running in the refrac liner. Such a calculation was modeled using a 2⅞-in. workstring connected to the 4¼-in. refrac liner, with well survey information for a range of friction factors from 0.2 to 0.3. The elastomer-clad refrac liner, with its inner string, was modeled as a composite string. To avoid buckling, it was necessary to use drill collars in the workstring. **Figure 4** shows that buckling is observed at roughly 9,600 ft, with a friction coefficient of 0.3. However, it was believed that a conservative estimate of the actual friction factor was 0.25, considering the values for typical muds used.

A second analysis was performed to understand a safe overpull margin during the expansion. This analysis considered the refrac liner as stationary, while the inner string is pulled from the bottom. While pulling out using a 0.25 friction coefficient, the overpull margin between the actual hookload and 80% of yield was calculated as 120 kips. With the anticipated pipe body expansion force of 57 kips, this would imply adequate overpull to expand the pipe.

Another engineering concern was the availability of technology to provide sufficient perforating of the refrac liner and the 5½-in., 17-ppf casing, as well as the availability of composite frac plugs that could be run and set in the refrac liner. Commercially available perforating guns and frac plugs were identified that could perform in the expanded 4¼-in. refrac liner.

Before installation began, all string components were drifted with their standard drift for the innerstring and for the 2⅞-in. tubing workstring. The wellbore was circulated until clean, and then drifted to the setting depth, using a special BHA with milling capability to ensure passage of the refrac liner and launcher. Water with calcium carbonate, lost circulation material (LCM) and liquid polymer helped plug off old perforations, so that circulation could be established on the clean out run. Viscous sweeps were circulated to ensure removal of any debris from the cleaning, until returns were clean. Then the well fluid was treated with a lubricant to enable low-friction running of the refrac liner into the horizontal section.

The first step of the installation was to run the launcher, made up to the lower anchor hanger into the wellhead. In this installation, liner was run using special handling equipment to avoid damaging the liner. The 0.06-in. connection sleeves were added over the connection pins of the liners, and the liner joints were made up to the specified torque for this refrac liner. The roughly 3,200 ft of the liner and anchor hangers were made up to the lower anchor hanger and held in the slips.

With the liner run into the wellhead, the casing tools were rigged down, and the innerstring running tools were rigged up. The inner string was then run into the refrac liner comprising an upper safety sub, followed by the joints of tubing and several joints with debris-catching devices. The inner string was tagged on the lower safety sub on the expansion cone assembly and rotated to screw into it. The liner was filled with clean, lubricated water. After the inner string was made up, the inner string tools were rigged down. A tapered guide was threaded unto the top of the upper anchor hanger to facilitate running of tools. The refrac liner assembly was then run down the wellbore using joints of 2⅞-in. workstring, connected to the inner string using a crossover, followed by drill collars, and then another crossover.

During running downhole, the liner hung up, 10 stands from the setting depth. It could not be washed down further, although it was broken free, so that its free pickup weight was determined as 130,000 lbf. To force it downhole further, the backside was filled with water, with the 2⅞-in. stripper rubber installed, and the refrac liner assembly was pumped down. The setting depth was confirmed by tubing tally.

The last stage of the installation was expansion of the liner. A rig rental pump was found to be sufficient for pumping the expansion. From the pump, 2-in. steel chiksan lines were connected to the workstring, and lines were tested to 5,000 psi. The 2-in. steel lines were used to circulate and land the dart. One tubing capacity was circulated at 2 bpm before pumping the dart to the float to pressure up, and initiating expansion. The dart seated with 2,800 psi, and the tubing was picked up with 130,000 lbf on the weight indicator. The rig pump was pressured up to 5,000 psi to initiate expansion at a rate of 0.5 bpm, and an expansion rate of 28 ft/min. Expansion of the first anchor hanger (with elastomers) was continued until completed and the refrac liner anchored in the base casing, as determined by putting on 20,000 lbf, overpull. Expansion was completed, making 50 full pulls to expand the liner racking back doubles with the aid of a drill pipe circulation (DPC) tool. Average expansion pressure was 3,000 psi, with 20,000 lbf, overpull. The liner was pressure-tested to 4,500 psi for five minutes before bleeding off. The float shoe in the nose assembly of the launcher at the end of liner was not drilled out.

The installation procedure went as planned, except for getting hung up short of the setting depth when running the refrac liner. In future refracs a special lubricant was added to the wellbore fluid that allowed running of the refrac liner to the setting depth with no problems.

Table 2. Initial fracturing treatment information for Wells #1, #2 and #3.

	Perf. Top, MD, ft	Perf. Base, MD, ft	Length, perf. Interval, ft	Volume, acid, gal	Volume, frac fluid, bbl	Proppant, lb	Avg. proppant conc., lb/gal	Frac fluid per ft interval, bbl/ft	Prop pant per ft of, interval, lb/ft
Well #1	7633	10628	2995	32000	37818	713000	0.45	12.63	238.06
Well #2	7917	10594	2677	24000	33012	625400	0.45	12.33	233.62
Well #3	7627	10186	2559	24000	21485	462860	0.51	8.40	180.88

Table 3. Ratio of Well #1 parameters to offset Wells #2 and #3 parameters.

	Post-refrac cumul. prod., 23 months, Mscf	Post-refrac cumul. prod., 23 months	Perf. interval length	Volume, acid, gal	Volume, frac fluid, bbl	Proppant, lb	Avg. proppant conc.	Frac fluid of per ft of interval	Proppant per ft of interval
Well #1	574168	1	1	1	1	1	1	1	1
Well #2	374523	1.53	1.12	1.33	1.15	1.14	1.00	1.02	1.02
Well #3	412397	1.39	1.17	1.33	1.76	1.54	0.88	1.50	1.32



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Fig. 5. Gas production history, pre- and post-refrac, for Wells #1, #2 and #3.

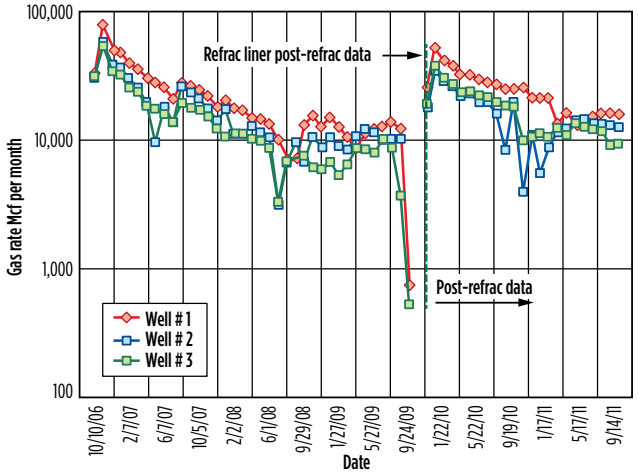


Fig. 7. Normalized gas production data for Wells #1, #2 and #3.

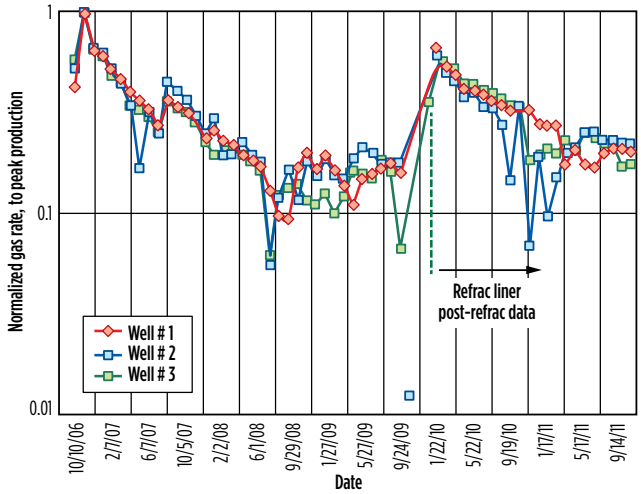


Fig. 6. Approximate relative positions of Barnett Wells #1, #2 and #3.

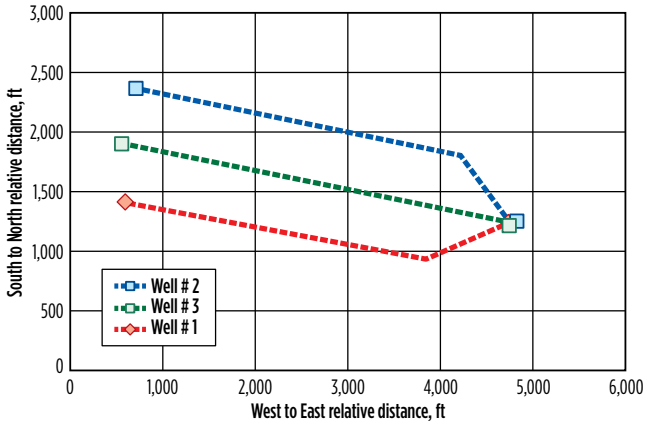
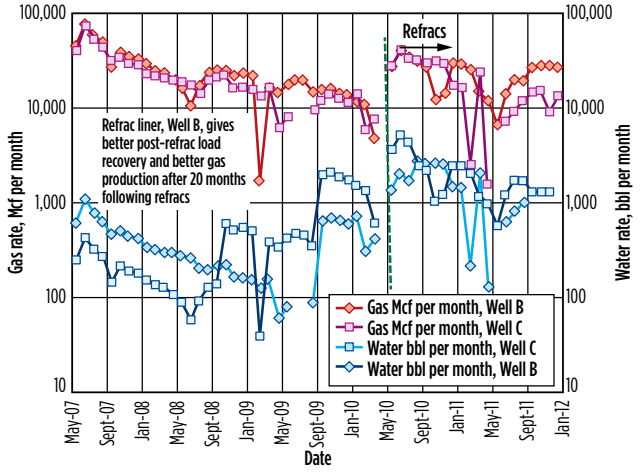


Fig. 8. Gas and water production rate histories, pre- and post-refrac, for Wells B and C.



PRODUCTION RESULTS

There is limited information regarding the details of the refrac of Well #1, except as was mentioned previously. It is known, however, that two offset wells on the same pad as Well #1, referred to here as Well #2 and Well #3, were also refractured at approximately the same time, using other methods of perforation diversion. The monthly production data for these three wells are public information, and the gas production is plotted in Fig. 5. Well #1 with the refrac liner shows post-refrac gas production as good as, or better than, those for the two offset wells. Public information on these wells also indicates that the original fracturing treatments for these three wells were similar, as shown in Table 2, and that the layout of these wells can be approximated, as in Fig. 6.

Figure 5 indicates that gas production for Well #1 with the refrac liner was better than that for the other two wells, for both the initial frac and the refrac treatment. The post-refrac production of Well #1 exceeds that for Wells #2 and #3 by more than 161 MMcf over the 23-month, post-refrac period shown in Fig. 5. Table 3 gives the cumulative post-refrac production for each well, and shows that the ratio of the production for Well #1 to offset Wells #2 and #3 is 1.53 and 1.39, respectively. Water production was variable and no definitive trends could be identified.

As shown in Table 3, any factors can contribute to this difference in production, including interval lengths and fracturing material parameters. It can be seen that the ratios of interval length, alone, cannot explain the difference in production. When comparing Well #1 with Well #3, it can be seen that the ratio of amounts of frac fluid and proppant used could explain the difference, but this does not hold true when Well #1 is compared with Well #2. Of course, the increase in production for Well#1 versus its two offsets could be an additive effect of all the variables. But, there are other factors that can also come into play, in addition to the fracturing parameters and the type of refrac diversion method. One is the location of the well. Figure 6 shows that Well #3 was positioned between Well #1 and Well #2, and could be impacted by hydraulic fracture overlap. Also, depending on the position of neighboring wells, the production for Wells #2 and #1 could also be impacted.

To account for the various factors that can affect the post refrac production, the production data in Fig. 5 were normalized to their initial peak post-frac production. In this way, it can be seen how the refrac performed relative to its initial frac, and, thus, one can judge the effectiveness of the refrac and can compare it with the effectiveness of the refracs of the other wells. Figure 7 shows

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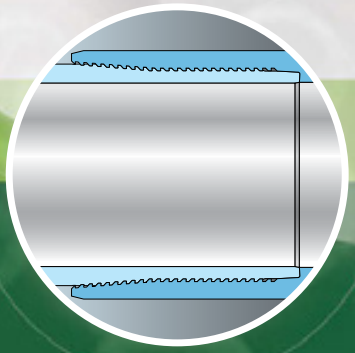
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the monthly production, normalized to the peak initial post-frac production for each of three wells. They are surprisingly similar. The peak normalized production for the three wells after the refrac ranges from 60% to 70%, with Well #1 having a peak normalized refrac production of 66%, and Well #3 having the highest at 70%.

Second case history. For the second case history, another Barnett refrac was done on a different pad (Well B) using the 4½-in. expandable liner in 5½-in., 17-lb/ft casing for perforation diversion. Another well on the same pad (Well C) was refractured at nearly the same time, using a different method of refrac diversion. Learnings from the first refrac (Well #1) were utilized when installing the refrac liner in Well B that facilitated the installation, most notably using the appropriate lubricant in the well fluid while running the roughly 3,400 ft of refrac liner. This lubricant was also used in the successful installation of roughly 4,300 ft of 4½-in. expandable liner in a lateral, with 5½-in., 20-lb/ft casing in the Marcellus shale.

The production performance of Wells B and C is shown in Fig. 8. The gas production rates for Well B with the refrac liner become greater after about one year of production. The total post-refrac gas production for these wells are 465,274 Mcf versus 373,415 Mcf for Wells B and C, respectively. Also, the post-refrac water rates are substantially greater than the initial water production rates, which may mean that these wells have fractured into water below (e.g. into the Ellenburger formation).

CONCLUSIONS

This study has shown that a solid-steel expandable liner with suitably positioned anchor hanger seals is a viable method for isolating perforations, to ensure that staged fracturing proceeds as desired. The liner can be run to the desired setting depth in long laterals, expanded downhole to achieve frac-stage/perforation isolation and to maximize liner ID, and perforated between old perforation clusters to stimulate new rock to maximize reserves.

The two case histories presented here indicate that production results using the expandable refrac liner give comparable, or better, gas production than other methods of perforation isolation, such as squeezing off the old perforations or diversion of flow from the old perforations using diverting agents. The results of the two sets of data show that initial water production following the refrac may be increased when using the refrac liner, which would be desirable to get the frac-fluid load back. However, continued water production is not conducive to production.

For these case histories, it is believed that individual perforation cluster isolation within each frac stage was not that necessary because of the small annular clearances between the base casing and expanded liner. Important steps for successfully running the liner were to circulate LCM to reduce flow into the old perforations, to achieve good circulation for cleaning the wellbore, and to use suitable lubricants in the wellbore fluid to reduce drag. Torque and drag analyses for the liner and workstring are also required to determine the need for drill collars near the liner top to avoid buckling.

The main advantage of the refrac liner in these case studies was in giving the operator assurance as to refracturing a given planned frac stage. Once this refrac liner is installed, the subsequent frac treatment can proceed more easily with less real-time diagnostic expenses and interruptions into the fracturing treatment to make downhole adjustments to help achieve the desired injection objectives. WO

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JOHN CAMERON is the Well Services Solutions manager at Enventure Global Technology in Houston, where he has worked for nearly two years. Before coming to Enventure, Mr. Cameron worked as a consultant with Eclipse Petroleum Technology in Houston, and as a consultant for PCM Technical in Tulsa, Okla. Before his role as a consultant, he worked as a staff engineer for 18 years at Amoco Production Technology Center in Tulsa. He received his PhD and MS degrees in chemical engineering from the University of Michigan and The Ohio State University, respectively, and a BS degree in mathematics from The Ohio State University. He is a registered PE in Oklahoma.

OCTG Technology Center optimizes connection performance in solid expandable liners

Field results show that solid expandable liners improve well architecture, reduce operational costs, mitigate drilling hazards and, in some cases, make previously undrillable wells drillable. However, radial expansion of the liner places severe combinations of bending, tension, compression and pressure on the threaded connections. If a connection fails during downhole expansion, the operation cannot be completed, and substantial additional intervention costs could be incurred. Therefore, connections with special features are required.

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Essentially, when a liner is expanded downhole, a new product is being manufactured, remotely, down the wellbore. Without exception, the product has to perform exactly as designed, so proper testing is critical to the success of solid expandable liner connections.

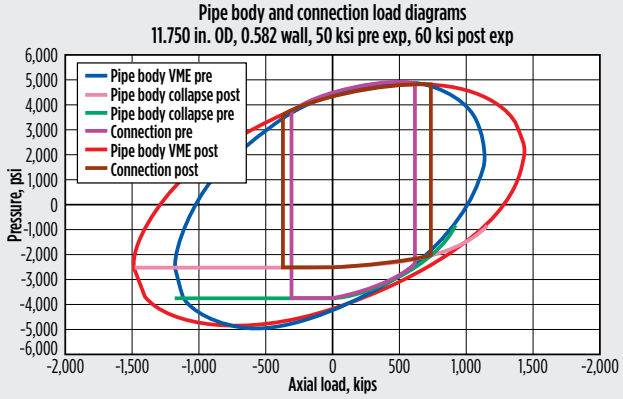
Recognizing that solid expandable liner connections need to be held to the same performance expectations as premium, nonexpandable connections, the company built the OCTG Technology Center, a 20,000-sq-ft testing facility in Huntsville, Texas. Here, rigorous qualification tests, designed to reflect realistic well conditions before, during and after expansion—and thus meet API RP 5-EX criteria—verify the unexpanded and expanded connections' tri-axial performance envelopes, **Fig. 1.** In addition, customized tests can be performed for clients with special application requirements, for connections with ODs up to 16 in.

On premises is an array of specialized laboratories and equipment, including a custom-built, dynamic-load expansion simulator, as well as a unique bending frame that enables researchers to study the effects of wellbore deviation on connections.

The first connections designed and tested at the facility were FODC-OR threaded connections, which are used for smaller-diameter liners. Two unique features enhance sealing capacity and help to effectively contain internal and external pressure: a single O-ring seal, and an engager ridge on the ID. With a two-step thread design, this connection can accommodate a single O-ring seal in the middle, as opposed to requiring one on each end of the connection. The patented engager ridge activates during expansion to amplify O-ring compression, further enhancing sealing capacity. To date, more than 200 FODC-OR expansion installations have been performed, in both cased and openhole applications.

With the introduction of these new threaded connections, specially designed to handle the considerable stresses to which solid expandable liners are subjected, operators are experiencing significant improvements in downhole performance and reliability. WO

Fig. 1. By maintaining compression and tension loads during expansion in the testing phase, Weatherford is able to reproduce all conditions experienced downhole, meeting API RP 5-EX testing requirements.



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Novel technique used to manage water encroachment in wells requiring gravel packing in Colombia's Ocelote field



Hocol (a subsidiary of Ecopetrol) rigs up to execute their next openhole gravel pack with ICDs, a technique now common in the Ocelote field in Colombia, where productivity and water encroachment control have been enhanced.

A novel water packing technique for wells that require gravel packing for sand control, and inflow control device (ICD) functionality to manage water encroachment, has resulted in 100% pack efficiencies in Colombia's Ocelote field. The technique has significantly reduced water cuts and substantially improved project economics.

BEATRÍZ VELEZ, WILLIAM CHARRY, ANKER DUARTE, JOHN RUBIANO, HERNANDO TRUJILLO and JOSE ALDEMAR TENGONO, Hocol; DARWIN FLOREZ, XIMENA GUERRERO, CLAUDIA NAVARRO and NICOLAS LOPEZ, Schlumberger

Ocelote field in the Llanos foreland basin is Colombia's most prolific hydrocarbon basin. A wildcat well in the field confirmed a monocline structure oriented in a northeast/southwest direction, developed in the footwall of the normal antithetic Guarrojo fault.

The main production interval is the Carbonera C7 formation, which produces 24° API oil. The formation has been interpreted initially as fluvial channel deposits associated with a broad shaly floodplain and highly unconsolidated sandstone.

In general terms, the Carbonera C7 formation consists of a monoclonal fault. The source rock is the Gacheta (Cretaceous), which is surrounded by black shales that are rich in organic matter.

Reservoir properties of the formation include a pressure of 1,643 psi and an average temperature of 173°F. Average porosity of the reservoir is 20%, and the average permeability fluctuates between 800 and 1,500 md. Water salinity is 100 to 150 ppm. The reservoir is fueled by a strong aquifer, and high water encroachment is expected within weeks of drilling a well.

COMPLETIONS METHODOLOGY

During development of Ocelote field, different technologies and techniques were used to address sand production issues within the Carbonera C7 formation.

The high heterogeneity of the formation sand, combined with the sand particle distribution, dictated that openhole gravel pack was the most favorable, effective technique for sand management in the field. Since implementation, no sand production has been experienced in any of the completed wells, and production potential has been exceeded in all the wells with lower drawdown applied. Once the sand control issues were addressed, Hocol decided to tackle the problems created by early water breakthrough and high water cut.

The reservoir has a full water drive producing mechanism that generates a fast increase in water production, which affects oil recovery and reduces well life. Most of the horizontal wells have shown a water cut of 90%, or more, in the first stages of production, providing an opportunity to develop a new completion approach that addressed sand control and water production, while also improving reservoir productivity by delaying water coning and breakthrough.

The entire completion architecture of the gravel-packed wells in Ocelote field included the openhole gravel pack assembly as its lower completion. In the upper completion section, an electrical submersible pump and a Y-manifold tool were implemented.

GRAVEL PACK DESIGN

The more extensive use and integration of simulators were crucial in optimizing and designing the best completion strategy for Ocelote field. The simulations provided a means for integrating the information from logs with reservoir parameters, such as permeability and pressure, in addition to a completion design that allowed for the evaluation of washout, severe doglegs in the openhole section and critical return rates.

Fig. 1. Schematic of the 5½-in. gravel pack assembly, including the 4½-in. ICD internal tubing and internal isolation system.

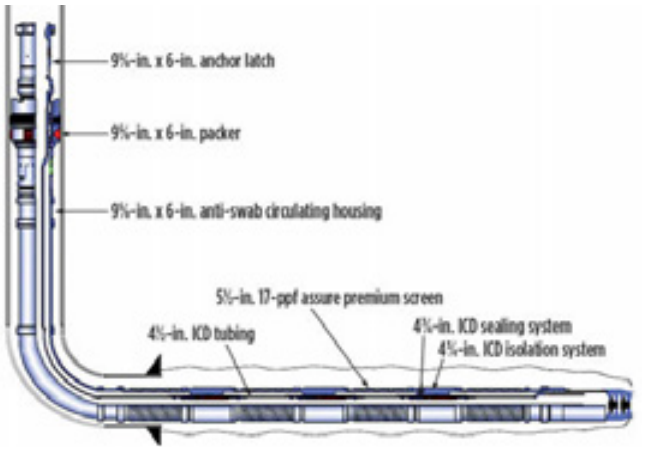
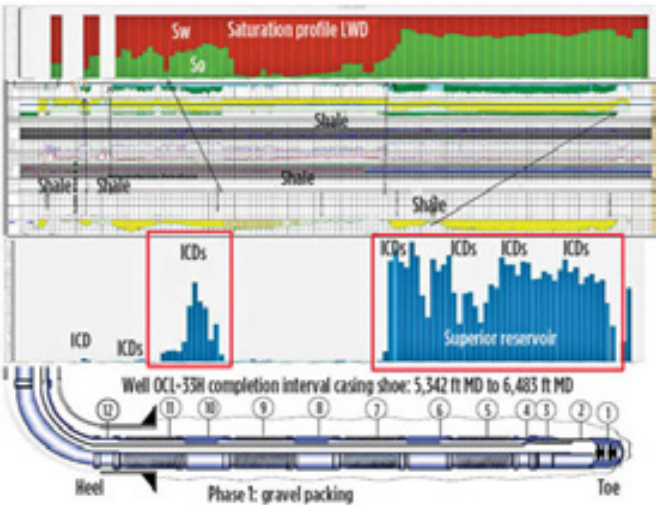


Fig. 2. Gravel-packed ICD completion design matching saturation and permeability profiles for Ocelote 33H.



The simulation's critical parameters—fluid type, sand size, pumping rate, leak-off, return rate to surface and bottomhole assembly (BHA) hardware—showed how each parameter worked in different situations, and what the expected results could be in packing efficiency.

The simulator was integrated with the acquisition software in real time, and it was adjusted with the prior circulation test. For this application, the use of flowrate sensors in the return line was important to quantify the return rates, and to have a better approximation of the well status before and during the job.

A new tool string design was implemented earlier in the campaign, and new functionalities in the service tool were incorporated to prevent pre-setting, true swab prevention capabilities and wash-down capability. A new screen construction was also implemented.

The new gravel pack service tool selected maintains hydrostatic balance during all critical operations of the gravel pack. In addition, the tool provided washdown capabilities in positive tool positioning indication. The tool's flow geometry was optimized to reduce the circulating pressure during the gravel pack, thus improving the likelihood of completing the gravel pack operation successfully. New, premium, sintered mesh screens were designed to optimize the number of base pipe perforations, the drainage layers, the design of the filtering media and high-flow shroud, to evenly distribute flowrates across the full area of the screen.

NEW ICD DESIGN

ICDs enable the balancing of flow across the entire horizontal section, to ensure even reservoir flow and a uniform production profile by applying adaptive flow restriction on high-flowrate zones. At the same time, low-production zones can be stimulated to mitigate early water conning, minimize water breakthrough tendency, achieve efficient areal draining, increase recoverable reserves and minimize the risk of bypassing reserves in the reservoir.

The benefits of horizontal gravel packs are achieved by integrating both techniques in one innovative, gravel-packed ICD completion. The new gravel-packed ICD string can be pulled out of hole, after completion if needed, to change nozzle distribution to suit reservoir changes.

Stand-alone screen (SAS) completions in the horizontal section were previously used in the field (Ocelote 3 and Ocelote 5). Because of sand particle distribution (uniformity coefficient and sorting coefficient) in Carbonera C7, these completions promptly suffered screen plugging that led to a low productivity index (PI).

It was necessary to gravel pack the wells, but achieving a successful, openhole gravel pack is dependent upon attaining a percentage of returns of no less than 90%, to establish sand dunes and alpha/beta waves. By incorporating a gravel pack and an ICD string, the expected results would reflect the best of both techniques.

To perform gravel packing in the selected wells, a 5½-in., 17-ppf, 250-microns screen was selected to allow for placement of ICD tubing, with the ICD nozzles inside 4½-in. flush joints.

To compartmentalize the reservoir, a 4¾-in. inner diameter (ID) ICD isolation system was placed between the screens. In the internal string, a 4¾-in. outer diameter (OD) ICD sealing system was developed specially for this application.

Figure 1 shows the most common setup, which includes a series of short polished bore receptacles (PBR) run with the screens, to complement the internal sealing system and not compromise the gravel pack's integrity. Figure 1 also shows the ICD nozzles incorporated inside the 4½-in. tubing and the seal assemblies that complement the internal isolation system.

Four wells were selected as the pilots for new technology: Ocelote 32H, Ocelote 33H, Ocelote SW8H and Ocelote 103H.

The first use of the horizontal gravel-packed ICD technique was with Ocelote 33H, with 1,144 ft of horizontal section. The well was completed using a 5½-in. screen and three ICD isolation systems to compartmentalize the well.

The gravel pack was completed with 100% packing efficiency. The localization of isolation systems was selected after calibrating logging-while-drilling (LWD) data and after-drilling petrophysical information, to maximize the selection and application of the ICDs with better productive potential, as shown in Fig. 2.

Production scenarios for this well, and others that implemented the gravel-packed ICD setup, were simulated using ICD placement and simulation software based on fluid properties,

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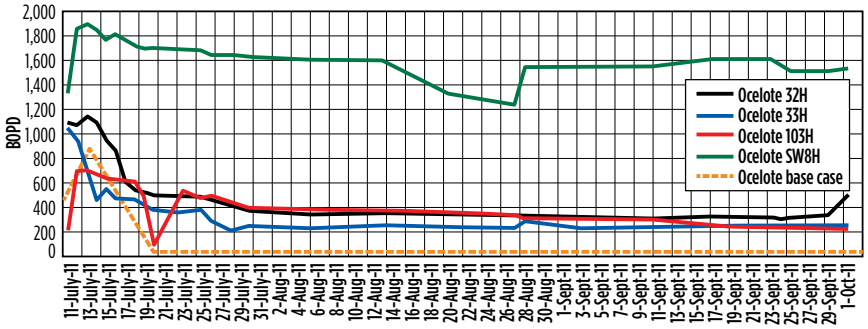
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Fig. 3. Production curves for the Ocelote base-case well, and the four wells completed with gravel-packed ICD isolation systems.



rock properties and initial reservoir pressure to place the internal nozzle-based ICD string.

The nozzle-based ICD internal string was run in-hole two weeks after completing the well, and production began two days later.

The second selected well was Ocelote 32H with 1,100 ft of horizontal section. This well was completed with a 5½-in. screen and six ICD isolation systems placed to compartmentalize the well. The gravel pack was completed with 100% packing efficiency.

The placement of ICDs was done following the same procedure used in the first well. The nozzle-based ICD internal string was run in hole two weeks after the initial completion and production began two days later.



Similar procedures were carried out on the third well, the Ocelote SW8H, with 1,075 ft of horizontal section, and Ocelote 103H, with 813 ft of horizontal section.

PRODUCTION PERFORMANCE ANALYSIS

To evaluate the production performance of the selected wells, the production data were plotted and compared to identify any existing trends. **Figure 3** shows the combined production curves from the four wells installed with graveled-packed ICDs, and the base-case well in the field.

Based on the production curves, Ocelote SW8H and Ocelote 32H were chosen to simulate a scenario without ICDs, so that a comparison of production, with and without the gravel-packed ICDs, could be conducted.

To evaluate the true performance of the gravel-packed ICD, a scenario without ICD (only gravel pack) was also simulated, and the real production data were input into a hydraulic simulator, and then calibrated with the input of Pr, Kv, Kh, So, Sw. Additional reference data were taken from the Ocelote base-case well to validate the accuracy of the results. Uncertainty was low in well sedimentology, petrophysical properties and geological structures, while uncertainty about the accuracy of the fluid properties was high.

Variations in saturation values (So, Sw) to match the real production data provided a match point to simulate a scenario without ICD. The hydraulic simulator generated match points that were plotted as curves, by which real production and production without ICD could be compared.

The results showed an effective basic solids and water (BSW) reduction in both cases. For example, by Oct. 3, 2011, the real BSW in Ocelote SW8H was 32% with ICDs, and the BSW calculated without ICDs was 69%. In Ocelote 32H, by Oct. 1, 2011, the real BSW was 87%, and the BSW calculated without ICDs was 95%. All wells in the field, prior to the implementation of gravel-packed ICDs, were showing real BSW over 90% within the first 30 to 45 days after completion.

As regards oil production, the results show better performance with ICDs, **Fig. 4.** By Oct. 3, 2011, the oil production from Ocelote SW8H was 1,230 bopd, and the production calculated without the ICD was 547 bopd. Similarly, by Oct. 1, 2011, oil production from Ocelote 32H was 456 bopd. Without using ICDs, production for the well would have been 169 bopd.

The results proved that the nozzle-based, gravel-packed ICDs worked properly and balanced the flow across the horizontal section. Additionally, results showed that the novel approach increased oil sweep in the reservoir, and reduced water breakthrough and conning effect, while delivering 100% gravel pack efficiency and sand-free production.

The design of the entire gravel pack completion allowed for the inner ICD string to be retrievable, providing the flexibility for reconfiguration of the nozzles and the spacing out of the ICDs.

This design improved the efficiency of the ICD completion and delivered even further productivity to individual wells or entire fields. In the case of Hocol, the plan was to retrieve, reconfigure and run the ICD strings again in the next stage of field development.

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NEW PRODUCTION LOGGING APPROACH

In the Ocelote wells, the Schlumberger horizontal and deviated well production logging system that was used incorporated multiple spinners covering the entire cross-section of the pipe. The logging system measured fluid velocity at five points across the vertical diameter of the well.

Electrical and optical probes positioned in close proximity to the spinners gave an estimation of gas, water and oil holdup. Additional challenges emerged, when well completions included screens, or when other types of flow in the annulus space were suspected (e.g. cement channeling or annular production flow). To obtain an accurate flow profile, uncertainties, such as variable hole ID and screen decentralization, had to be overcome.

It was, therefore, necessary to combine measurements that covered both the inside of the completion, and the annular space between the tubular and the formation. Such an approach was obtained by running the horizontal well production logging tool, combined with a reservoir saturation tool.

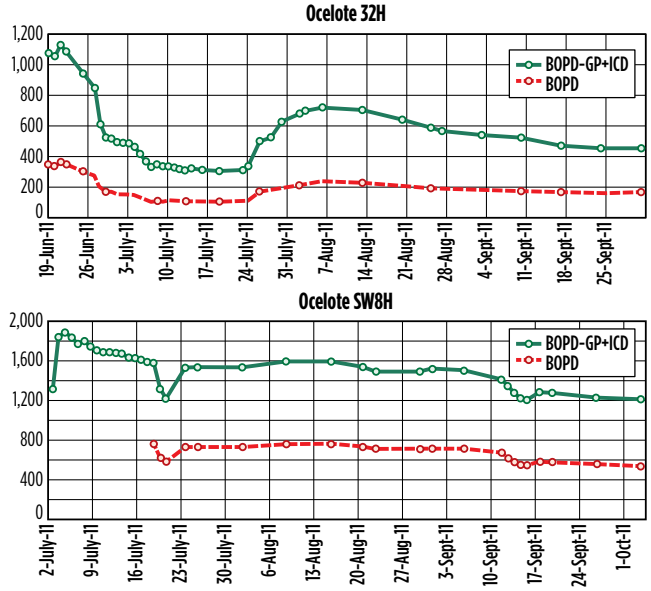
Two applications of the reservoir saturation tool were used in this case: a three-phase fluid holdup log from pulsed neutron measurements, and a water flow log. Unlike other applications, the tool was run centralized, and measurements of water velocity and phase holdup were obtained inside the wellbore (both annular and pipe) by the acquisition of station logs.

The general logging program for the wells included production logging tool passes with the well shut-in, and with the well flowing at a stabilized flowrate; water flow log stations for water velocity measurements; and continuous pass for acquisition of three-phase fluid holdup data.

A combination of the production logging and reservoir saturation tools was run in the four wells completed with gravel-packed ICDs in open holes. The internal ICD system was retrieved prior to the logging run. The same log was run in wells with an arrangement of ICDs, and through the upper completion.

Production rates for the wells in the campaign ranged from 2,800 to 3,500 bfpd, with a water cut between 92% and 96%. Produced oil had 23°-to-25° API gravity, and production water had salinity close to 200 ppm. In this environment, water holdup was measured with optical probes, using the previously described methodology.

Fig. 4. Oil production comparison for Ocelote 32H and Ocelote SW8H.





CONCLUSIONS

In most of the cases, oil production was found to come from the toe of the wells in the B1 sand. Oil production was associated with a significant water cut from startup. Intervals of 100% water cut production were found along the horizontal section in the wells logged, also in the B1 sand.

Effective production length in the logged wells was reduced to the B1 sand portion. In some cases, this producing zone was found to be as low as 400 ft, out of 1,000 ft of total horizontal length. None of the wells logged showed any production contribution from along the horizontal section.

In terms of fluid production, the wells completed with the ICD system responded positively in terms of water cut reduction, which proved the system's efficiency.

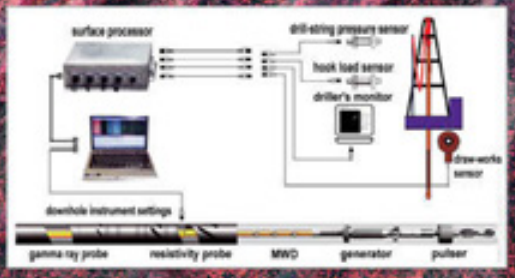
The project shows an effective integration of nozzle-based ICD technology with horizontal gravel-pack completions, to improve well productivity in applications where the SAS technique is not advisable.

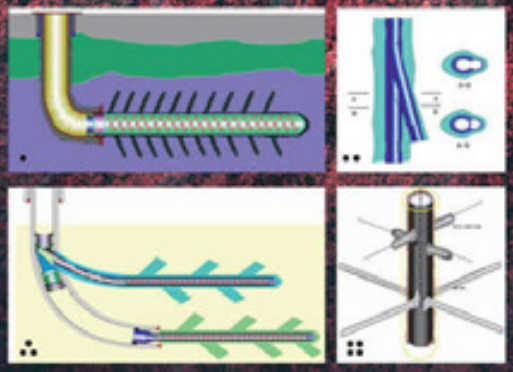
An integrated sand management approach was an effective solution in the successful completion of the four wells in this project, resulting in 100% packing efficiency and installation of the nozzle-based ICD, with no quality, health, safety or environmental issues.

The group of depleted wells benefited when using the ICD, reducing BSW by 7% to 8%. The impact was greater in Ocelote SW8H, which experienced a 37% reduction of BSW.

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The gravel-packed ICD completion showed benefits over horizontal openhole gravel-pack systems, in terms of BSW reduction and oil recovery, translating to improved field productivity and increased well longevity. These gravel-packed ICDs are the first true retrievable ICD system available for wells requiring inflow control and gravel packing. WO

BEATRÍZ VELEZ COLMENARES is a development geologist with experience in basin evaluation studies, static model generation from 3D seismic interpretation and reservoir characterization integrating surface geology, well log, core, petrophysical, biostratigraphic, petrographic, seismic, production and pressure information and data; completions recommendations, development plans, risk assessment and classification perspective, effective reserve development and E&P cycle optimization. She graduated from the Universidad Industrial de Santander, Colombia, in 1999, and has been with the Hocol production team since 2006.

WILLIAM MAURICIO CHARRY is a production technology engineer for Hocol, working mainly on field development technology. He graduated with a petroleum engineering degree from the Surcolombiana University (USCO), Colombia, and has been part of Hocol since 2006.

ANKER DUARTE is working as a reservoir engineer at Ocelote field for Hocol, mainly executing the field development plan, overseeing the reservoir and continuously looking for opportunities to increase production using analytical and numerical models. He has a BS degree from the Universidad Industrial de Santander, Colombia, and has 10 years of experience in the petroleum industry.

JOHN RUBIANO is a petroleum engineer with 13 years of experience in the oil and gas industry. Mr. Rubiano is working with Hocol in Colombia as a completions and workover engineer, and sand control specialist.

HERNANDO TRUJILLO is a petroleum engineer with more than 23 years of experience working in the oil and gas industry. Mr. Trujillo is working with Hocol in Colombia as a senior operations engineer, and completion, workover and sand control specialist.

ALDEMAR TENGONO is a petroleum engineer with more than 17 years of experience working in the oil and gas industry. Mr. Tengono is working with Hocol in Colombia as a senior completion and workover engineer, and sand control and heavy oil specialist.

DARWIN FLOREZ has worked in the oil and gas industry for more than 13 years, all with Schlumberger. Mr. Florez is in sand control technical support for Colombia, working mainly on sand control tools, and complex lower and upper completion designs for different operators.

XIMENA GUERRERO is a petroleum engineer with nine years of experience in the reservoir engineering environment. Ms. Guerrero supports the completions segment in Schlumberger as reservoir domain champion in charge of developing, from the technical side, new and complex completions technologies. She has extensive experience in production logging, and pressure and fluids analysis.

CLAUDIA NAVARRO is Schlumberger's fracturing technical engineer for northeastern Brazil, working mainly with fracturing and stimulation applications on land for tight and shale formations. Previously, she worked in Colombia as technical support for fracturing and sand control. She graduated with a petroleum engineering degree from the Universidad America, Colombia, and has been part of Schlumberger Well Services since 2004.

NICOLAS LOPEZ is the global business development manager for sand control, screens and ICDs at Schlumberger, based in Houston. He has more than 15 years of industry experience, including worldwide assignments in technical and management roles. Mr. Lopez has been involved in the design of completions and sand control projects around the world, and new technology innovation and commercialization of products at Schlumberger. He holds BS degrees from Texas A&M University, an MBA degree from the ITESM in Mexico, and an MS degree in petroleum engineering from Herriot Watt University.





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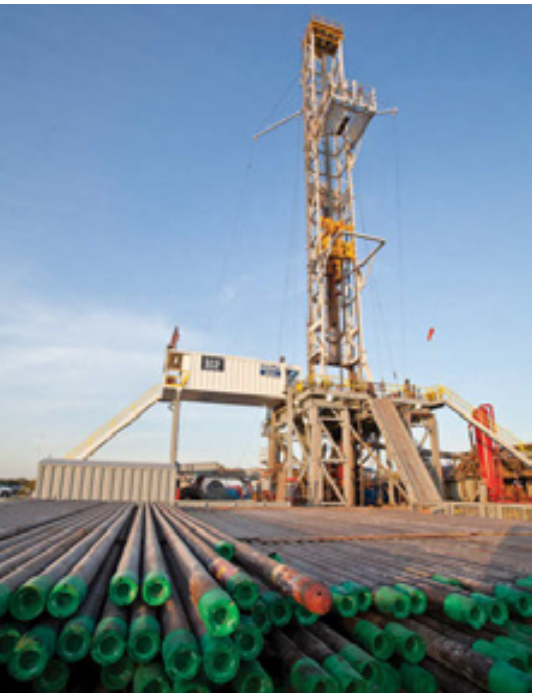
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Stagnation prevails at a high level



Producers in the U.S. continue to be concerned about regulatory uncertainty, and as such, the number of wells drilled may not reach the 45,000-per-year mark. In Canada, producers are concentrating on oil production, while being concerned about oil transportation and gas prices. Activity in Mexico is about to slow down appreciably.

KURT ABRAHAM, Executive Editor, and **MAURO NOGARIN**, Contributing Editor, Latin America

Statoil has taken over operation of the eastern half of its Eagle Ford acreage. Photo by Mieko Mahi, courtesy of Statoil.

Although oil prices are higher than they were a year ago, there has not been a stampede of operators to drill extra wells in the U.S. Part of the reason for this is a continuing problem with infrastructure being swamped in key plays, particularly liquids-oriented shales. Furthermore, given a relatively weak national economy, operators are being careful not to over-drill.

Yet, as prices approach $100/bbl in recent weeks, there may be a temptation among smaller independents to drill a few extra wells, to take advantage of high prices. Producers in the U.S. continue to be concerned about regulatory uncertainty in Washington, D.C., as well as some state capitals. In addition, there are questions about how soon, and on what scale, natural gas exports in the form of LNG might begin to take place. President Obama's refusal to approve construction of the Keystone XL Pipeline is also hampering the movement of growing supplies of crude in the U.S.

Accordingly, the ceiling on E&P activity remains, as the number of wells drilled continues to be unable to reach the 45,000-per-year mark and beyond. Yet, U.S. oil production is running 15% to 20% above 2012 levels, exceeding 7.2 MMbpd.

For the balance of 2013, *World Oil's* forecast includes these highlights:

- U.S. drilling will rise 9.5%, from 20,992 wells in first-half 2013 to 22,988 in the second half
- On a year-to-year basis, U.S. drilling will decline 3.8% to 43,980 wells in 2013, from 45,717 wells in 2012; this compares to our original 2013 forecast of 47,053 wells
- The amount of U.S. footage drilled will increase 9.1%, to 183.9 million ft of hole in second-half 2013, from 168.6 million ft in the first half. However, year-on-year, footage drilled will decline 3.0%, to 352.5 million ft. Due to more horizontal wells and greater footage per well, the annual amount of footage drilled this year is declining at a slower rate than the well count.
- The U.S. rig count during second-half 2013 may register a mild increase of 70 to 80 units
- Due to increased use of pad drilling and gains made in drilling efficiency, a smaller increase in rig count may be sufficient to satisfy a higher percentage growth in well count.

U.S. prices. Oil prices have, for the most part, remained above $90/bbl for WTI on futures markets, during the first seven months of 2013. Indeed, in recent weeks, the price has flirted with levels just above $100/bbl. This has exacerbated the flight of operator drilling capital, away from gas and toward oil. It also appears to be encouraging an increase in "discretionary" development drilling by smaller independents, looking to cash in on higher prices.

By contrast, natural gas prices have yet to recover to a level sufficient to attract operators back to gas drilling. Although gas prices have come close to $4/Mcf, they have yet to get above that level and stay there. Until that happens, there will not be a major increase in gas-directed drilling.

U.S. rig count. As of July 19, the Baker Hughes U.S. rotary rig count totaled 1,770, down 8.5% from the 1,935 figure recorded during the same week in 2012. For nearly the first seven months of 2013, the U.S. rig count averaged 1,759.9, down 10.9% from the 1,975.3 average of the same period in 2012. A hoped-for recovery in the U.S. count during the back half of 2012 never occurred. Instead, the count declined steadily, falling below 1,800 by the end of the year. We believe that this decline reflects the near-abandonment of gas-directed drilling by many operators, in favor of focus-

Table 1. Mid-year revision, 2013 U.S. drilling forecast.

State or area	2013 wells				2013 footage, 1,000 ft			2012 wells[4]	2011 footage, 1,000 ft[4]
	First half	Second half	Year	% difference, 1st half vs. 2nd half	First half	Second half	Year		
Alabama[1]	85	83	168	-2.4	680.0	672.3	1,352.3	169	1,047.8
Alaska	60	75	135	25.0	279.0	348.8	627.8	133	603.2
Alaska-offshore[2]	6	11	17	83.3	100.8	184.8	285.6	19	304.7
Arkansas	395	375	770	-5.1	3,081.0	2,925.0	6,006.0	974	7,889.4
California	1,450	1,850	3,300	27.6	1,509.5	4,512.2	6,021.7	3,103	7,200.5
California-offshore[2]	31	57	88	83.9	47.1	284.4	331.5	74	280.0
Colorado	1,183	1,406	2,589	18.9	10,410.4	12,372.8	22,783.2	2,745	22,797.2
Gulf of Mexico[2]	146	219	365	50.0	4,289.2	4,345.0	8,634.2	314	4,459.0
Illinois	407	460	867	13.0	884.0	999.1	1,883.1	781	1,696.5
Indiana	73	73	146	0.0	143.2	141.0	284.2	206	392.0
Kansas	2,043	2,288	4,331	12.0	5,538.6	6,207.3	11,745.9	4,550	11,861.9
Kentucky	115	225	340	95.7	241.5	472.5	714.0	340	714.0
Louisiana[1]	564	564	1,128	0.0	3,856.5	3,856.5	7,713.0	1,127	7,712.9
North	371	371	742	0.0	1,927.6	1,927.6	3,855.2	741	3,855.2
South	193	193	386	0.0	1,928.9	1,928.9	3,857.8	386	3,857.7
Michigan	66	66	132	0.0	232.5	232.8	465.3	153	534.7
Mississippi[1]	114	115	229	0.9	946.2	989.0	1,935.2	208	1,664.0
Montana	110	126	236	14.5	1,188.0	1,360.8	2,548.8	335	3,182.5
Nebraska	62	75	137	21.0	217.0	352.5	569.5	108	565.5
New Mexico	702	729	1,431	3.8	5,124.6	5,332.6	10,457.2	1,515	11,400.4
New York	47	60	107	27.7	82.5	105.3	187.8	176	295.0
North Dakota	990	1,142	2,132	15.4	18,500.0	21,400.0	39,900.0	2,010	37,704.8
Ohio	515	550	1,065	6.8	3,090.0	3,355.0	6,445.0	632	3,811.0
Oklahoma	1,550	1,665	3,215	7.4	14,260.0	15,180.0	29,440.0	3,161	29,289.2
Pennsylvania	1,038	1,038	2,076	0.0	7,505.4	7,505.4	15,010.8	2,375	16,490.4
South Dakota	14	10	24	-28.6	165.5	115.0	280.5	14	156.0
Tennessee	64	68	132	6.3	139.5	148.2	287.7	135	284.9
Texas[1]	7,968	7,905	15,873	-0.8	76,630.1	76,332.9	152,963.0	17,315	166,832.6
District 1	1,242	1,296	2,538	4.3	13,413.6	13,996.8	27,410.4	2,530	27,783.4
District 2	569	576	1,145	1.2	8,478.1	8,582.4	17,060.5	1,175	17,508.8
District 3	326	336	662	3.1	2,542.8	2,688.0	5,230.8	667	5,158.9
District 4	256	243	499	-5.1	2,822.4	2,680.3	5,502.7	609	6,784.2
District 5	251	208	459	-17.1	2,841.3	2,354.6	5,195.9	849	9,610.2
District 6	191	182	373	-4.7	2,253.8	2,147.6	4,401.4	493	5,925.2
District 7B	398	406	804	2.0	2,149.2	2,192.4	4,341.6	841	4,671.1
District 7C	858	853	1,711	-0.6	8,151.0	8,188.8	16,339.8	1,768	16,517.4
District 8	2,574	2,530	5,104	-1.7	23,423.4	23,086.3	46,509.7	5,571	50,281.3
District 8A	464	444	908	-4.3	2,969.6	2,841.6	5,811.2	886	5,539.8
District 9	469	459	928	-2.1	3,329.9	3,258.9	6,588.8	1,084	7,492.5
District 10	370	372	742	0.5	4,255.0	4,315.2	8,570.2	842	9,559.8
Utah	408	577	985	41.4	3,433.7	4,795.4	8,229.1	1,068	8,876.2
Virginia	77	78	155	1.3	228.8	231.7	460.5	179	554.5
West Virginia	228	232	460	1.8	1,960.8	1,995.2	3,956.0	465	4,045.5
Wyoming	392	750	1,142	91.3	3,726.8	7,000.0	10,726.8	1,150	10,400.0
Others[3]	89	116	205	30.3	102.5	178.0	280.5	183	220.6
Total U.S.	20,992	22,988	43,980	9.5	168,594.7	183,931.5	352,526.2	45,717	363,266.9

[1] Excludes state and federal offshore wells, which are included in the GOM total. [2] Includes state and federal offshore wells.
[3] Includes Arizona, Florida, Missouri, Nevada, Oregon and Washington. [4] 2012 estimates are based on well counts furnished by state and federal regulatory agencies, and API.

ing on oil development, particularly in the shale plays.

Since the beginning of 2013, the U.S. count has remained in a narrow range between a low of 1,738 and a high of 1,770. Based on data supplied by state agencies and operators, we predict that there may be a mild recovery in the rig count of no more than 70 to 80 units, just enough to help achieve the drilling gain forecast for second-half 2013. Over the last 12 months, it also has become apparent that the rig count, alone, is no longer an infallible barometer of drilling activity. There are too many factors clouding the issue, including the need for fewer rigs to drill the same number of wells, due to pad drilling and other efficiency gains, along with greater numbers of horizontal wells and the ever-growing lengths of those horizontal sections.

A year ago, the oil-gas split in the Baker Hughes U.S. rig count was about 73%/27% in favor of oil. That split further widened for oil to the point that during the last two-and-a-half months, it has flirted with an 80%/20% ratio. However, it had not broken this barrier, as of the last week of July. This may still happen at some point in the next few months.

State-by-state highlights. In state after state, oil has supplanted gas as the target of choice. Although gas prices have improved moderately, it is not enough to convince operators to restore any significant share of gas-directed drilling. Meanwhile, the drilling of horizontal wells continues to increase, and the length of these

sections is growing. This requires greater numbers of frac stages, and it also means that the amount of footage drilled is noticeably higher.

In **Texas,** activity continues to be driven by the two major drilling hubs, the Eagle Ford shale of South Texas and the Permian basin of West Texas. Encompassing part or all of Railroad Districts 1, 2 and 3, the Eagle Ford is ensuring that activity this year stays very close to the levels of 2012. Combined, these three districts will be up 3.3% during second-half 2012 at 2,208 wells, compared to the first half. However, these three districts, year-on-year, will be down slightly (-0.6%) at 4,345 wells.

In the Permian basin, which covers large portions of Districts 8, 8A and 7C, oil-directed drilling continues to dominate, with increasing numbers of horizontal wells drilled. The lengths of those horizontal wells continue to grow, as well. Nevertheless, operators have exercised some caution this year, cutting back slightly on new drilling while waiting for a backlog of completions to finish. Accordingly, their drilling in these three districts, combined, will be down 1.8% in second-half 2013 at 3,827 wells, compared to the first half. In addition, the three districts, together, will be down 6.2% at 7,719 wells versus 2012's level. Even so, Districts 8, 8A and 7C, combined, will account for 48.6% of all Texas drilling.

On the other side of the ledger, activity remains depressed for gas-prone districts. In Districts 4 (deep South Texas, along the Gulf Coast), 5 (Barnett shale, East Texas) and 6 (East Texas), the combined second-half drilling total will be

An Anadarko Petroleum rig drills in the Wattenberg field, near Denver.





just 633 wells, down 9.3% from first-half 2013. On an annual basis, the picture is even bleaker. Together, the three districts will see just 1,331 wells combined, a 31.8% drop from 2012's 1,951 wells.

In neighboring **Oklahoma,** activity remains solid and growing. Outnumbering gas-directed drilling three to one, tight oil plays in western parts of the state continue to dominate, keeping rig counts high.

A crew works on the drill floor of a rig in Apache Canada's House Mountain operating area.



There will be a 7.4% increase in drilling during second-half 2013, to 1,665 wells. In addition, the year-on-year comparison shows 3,215 wells expected for 2013, up 1.7% from 2012's figure.

In **Louisiana,** the Department of Natural Resources' Office of Conservation believes that activity has stabilized. In fact, it is so stable, officials predict that second-half drilling in both the northern and southern portions of the state will equal first-half levels. In addition, the state predicts that new well drilling this year, overall, in both halves of Louisiana will virtually equal activity levels during 2012. There will be 564 wells (371 in the North, 193 in the South) in each half of the year, with 2013's 1,128 wells barely exceeding 2012's 1,127 wells. In the North, where natural gas once dominated, operators have made a major shift toward oil. Drilling for oil now outnumbers gas-directed wells two to one. In the South, activity is even more one-sided, with oil drilling comprising eight out of every 10 wells.

Although infrastructure in **North Dakota** is being stretched to capacity by the nation's leading shale play, the Bakken,

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drilling will again post an increase. Compared to 2012, wells drilled will be up 6.1%, at 2,132. In addition, second-half drilling will be up 15.4%, at 1,142 wells, versus the first-half total. Keeping pace with Texas in terms of oil development, North Dakota remains the second-largest oil producer behind Texas and the federal Gulf of Mexico, producing close to 800,000 bpd.

In the Northeast, **Pennsylvania** is benefitting from operators' exploitation of the wet gas window of the Marcellus shale, helping to stabilize activity that plummeted amid low gas prices. Accordingly, while activity will be down 12.6% from 2012's level, the number of wells drilled in each half of 2013 will be equal at 1,038. In neighboring **Ohio**, exploitation of the oil-prone Utica shale is pushing 2013 activity considerably higher. Drilling during second-half 2013 will also be higher. In **West Virginia**, drilling will remain very close to the 2012 level, at 460 wells. There will also be a slight increase in the second half, as opposed to the first-half level. In what had been an almost exclusively gas-directed state, oil now comprises 30% or more of all activity.

In the Rockies, there will be second-half increases over first-half activity in **Colorado, New Mexico** and **Utah**. However, as compared to 2012 levels, drilling during all of 2013 will be down moderately in all three states. Colorado continues to be affected positively by the Niobrara shale, with a majority of wells, statewide, now targeting oil. New Mexico's activity is being driven by drilling in the southeastern section of the state, particularly in its portion of the Permian basin. Again, oil is dominating the picture, with oil-directed drilling outnumbering gas wells about 10 to one.

California's upstream sector is almost entirely oil-directed at the moment. Leading the way are the state's two largest operators, Aera Energy and Occidental Petroleum. Along with other operators, they will push activity 28% higher during second-half 2013. In addition, compared to 2012's level, the full-year total will be 6.3% higher. The vast majority of activity will be development wells in established fields, although a few exploratory wells may be spudded in the Monterey shale.

As concerns **Alaska,** activity in the Arctic offshore has come to a standstill, highlighted by Royal Dutch Shell's decision to take a hiatus this year. In the meantime, activity remains concentrated in traditional areas, including the North Slope and Cook Inlet. The state's Oil & Gas Conservation Commission believes that there will be a 25% gain in onshore drilling during second-half 2013. Compared to all of 2012, this year's total well count will be up slightly.

About these statistics. *World Oil's* U.S. tables are produced with the aid of data from a variety of sources, including API, the Texas Railroad Commission, other state and federal regulatory agencies, and a variety of operating companies. We thank all contributors for their time and effort in providing data and analysis.

World Oil editors try to be as objective as possible in the estimating process, to present what they believe are the most current data available. Sound forecasting can only be as reliable as the base data. In this respect, is should be noted that well counting is a dynamic process, and most historical data will be continually updated over a period of several years before "the books are closed" on any given year.

CANADA

Given the high crude price environment of the global upstream industry, Canadian producers are making money by concentrating on development of additional oil production. Yet, they are not wildly happy about their overall situation. There are concerns about how crude oil is going to be transported and moved around, if new pipeline capacity is not built quickly enough to keep up with growing supplies, including the delay of the U.S. Keystone XL Pipeline. Producers also fret about the future of gas drilling, production and exports, as they watch and wait for gas prices to recover. In summary, it will be a solid, healthy year for Canada's upstream but not an outstanding one.

Drilling. There were 13,149 wells drilled (including eight offshore) last year, totaling 72.3 MMft of hole. Oil completions accounted for 64.1% of new wells drilled, numbering 8,432. Gas wells drilled totaled just 1,110. This year, CAPP predicts a 12.5% drop to 11,510 wells, including 10 offshore.

According to the Canadian Association of Oilwell Drilling Contractors (CAODC), the Canadian upstream industry, in line with drilling more oil wells, continues to drill complex horizontal wells and averages 11.4 days per well. Meanwhile, the National Energy Board (NEB) released its natural gas deliverability energy market assessment, indicating that Canadian natural gas producers are undertaking minimal gas drilling activity, as current prices do not cover the full costs of developing most natural gas prospects.

In its report, *Short-term Canadian Natural Gas Deliverability 2013-2015*, the NEB examines trends for natural gas deliverability in Canada (the ability to produce gas from new and existing wells). The three key supply and demand drivers influencing future Canadian gas deliverability include:

- Minimal drilling activity, because prices do not cover the costs of developing most natural gas prospects.
- Growth in natural gas as a by-product from developing oil- and NGL–rich prospects.
- Producers are not earning sufficient returns to attract additional equity investment with current prices at around $3/MMBtu in western Canada.

Production. Combined output of crude and condensate was up 6.8% last year, averaging 3.067 MMbpd. Within that figure, conventional production averaged 1.324 MMbpd, up 3.6% from 2011's figure. Oil sands production was 1.743 MMbpd, a 9.3% increase over the previous year.

In its annual crude forecast released June 10, 2013, the Canadian Association of Petroleum Producers (CAPP) predicted that Canadian oil production will more than double to 6.7 MMbpd by 2030, from 3.1 MMbpd in 2012. This includes Alberta oil sands production of 5.2 million bpd by 2030, up from 1.7 million bpd in 2012. While the overall trend is similar to last year's forecast, the notable differences include an increase in total production of 500,000 bpd by 2030, the industry group stated. The increase includes incremental conventional production of 300,000 bpd by 2030 and oil sands production of 200,000 bpd by 2030. The forecast also includes a progressive shift toward more supply from oil sands in situ output.

An Energy Resources conservation (ERCB) report indicates the largest conventional crude oil production and reserves increase in decades for Alberta. The

latest edition of the ERCB's publication, Alberta's *Energy Reserves 2012 and Supply/Demand Outlook 2013–2022,* shows a 14% increase in production and 9.5% increase in reserves over 2011 levels. In 2012, Alberta's crude oil production totaled 556,000 bpd, with a yearly total of 204 million bbl. This increase is due to the higher production rates of horizontal wells.

In 2012, Alberta produced 1.9 MMbpd of raw crude bitumen from the oil sands, for a yearly total of 704 MMbbl, or a 10% increase over 2011's crude bitumen production. The ERCB forecasts that Alberta's annual raw crude bitumen production will total 3.8 MMbpd for a total of 1.39 Bbbl/year in 2022. The report notes that, since 1967, Alberta has produced about 8.8 Bbbl of raw crude bitumen from the oil sands and about 16.7 Bbbl of crude oil since 1914. Other report highlights include:

- Alberta's total remaining established crude bitumen and crude oil reserves stood at 169.6 Bbbl, consisting of 167.9 Bbbl of crude bitumen and 1.7 Bbbl of crude oil.
- Remaining, established, marketable, conventional gas reserves stood at 33 Tcf, a decrease of 3% from 2011
- Remaining established reserves of NGLs stood at 1.6 Bbbl, down 1% from 2011.

Land sales stabilize at lower level. Alberta collected $13.21 million at its June 9, 2013, land sale. The average price of $215.08 per hectare was the second-lowest of the calendar year. The province sold 61,408 hectares at the land sale. So, year to date, the industry has spent $403.47 million in Alberta to tie up 1.16 million hectares, which has generated an average price of $347.87 per hectare.

As of June 2012, Alberta had collected $589.73 million on 1.35 million hectares, at an average price of $437.40 per hectare. Highlights of the sales included a bonus high bid of $2.26 million, submitted successfully submitted by Vertex for a 2,048-hectare license in northwestern Alberta, south of Grande Prairie.

In Saskatchewan, a June 2013 sale of petroleum and natural gas rights generated $9.6 million in revenue for the province. To date, revenue from three land sales held by the provincial government have earned $29.3 million. In the June sale, the Weyburn-Estevan area received the most bids, totaling $7.9 million. "We have seen production in the Bakken area (of Saskatchewan) reach 69,000 bpd, and this is driving investment in the area," said provincial Energy and Resources Minister Tim McMillan. "The majority of the lands sold in the Weyburn-Estevan area are targeting Bakken-prone lands, accounting for more than 80% of the sale total."

MEXICO

Activity in Mexico continued at an elevated pace last year, but that level of activity may be about to slow down noticeably. According to state firm Pemex, there were 1,238 wells drilled during 2012, up 19.7% from 1,034 wells in 2011. Footage drilled was 9.97 million, up 21.6% from 8.20 million in 2011.

Offshore activity totaled 50 wells, up 16.3%. Offshore footage drilled was 686,492 ft, down 1.6% from 697,602 ft.



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Crude and condensate production was down slightly at 2.593 MMbpd. Natural gas output was down 3.2%, at 6.4 Bcfd. Crude and condensate reserves were up 0.2% at 10.283 Bbbl.

During fourth-quarter 2012, Pemex conducted 3D seismic surveys totaling 6,791 km^2, an area 38% less than what was surveyed in the same quarter of 2011. In the Northern region, the firm surveyed 6,450 km^2, of which 94.5% were for exploration and 5.5% were for development.

During the same quarter, from October to December, Pemex gathered 2D seismic data over an area of 1,226.4 km^2, of which 86.2% were in the Northern region, and 13.8% were in the Southern region. These seismic surveys were 20.6% greater than the corresponding quarter in 2011 and were directed toward prospecting for shale gas deposits.

During fourth-quarter 2012, Pemex completed 344 wells, 17.4% more than in the same quarter of 2011, located mainly in the area of Agua Fría-Coapechaca-Tajín and Humapa-Bornita, in the Integral Tertiary Oil Production area of the Gulf of Mexico. Of the total, 95.6% of wells completed were for development, and 4.4% were exploratory. An additional 15 exploratory wells were also completed, which is 114.3% more than in the same quarter of 2011. The completion rate for exploratory wells was 66.7%, which included five oil- and gas-producing wells, three gas-and-condensate wells, one dry gas well, and one wet gas well. Three wells were declared unproductive, due to water content. During the same fourth quarter, 329 development wells were completed, 43 more than in the identical quarter of 2011.

During fourth-quarter 2012, average crude oil production was 2.56 MMbpd, a 0.4% increase over equivalent production in fourth-quarter 2011. Most of the increase came from the Cinco Presidentes, Tabasco Gulf Coast, Poza Rica-Altamira and Abkatun-Pol-Chuc production fields. As of Jan. 1, 2013, estimated total reserves (3P)—proved, probable and possible—were 44.53 Bbbl of crude oil, with 31.2% proven, 27.6% probable and 41.2% possible.

During first-quarter 2013, 3D seismic data were gathered over 5,114 km^2, which is 12% less than the amount collected in first-quarter 2012. There were also 549.7 km of 2D seismic obtained, or 19.4% less than the amount gathered a year earlier. About 48% of the data were from the Northern region, and 52% were in the Southern region.

During first-quarter 2013, 252 wells were completed, 5.6% less than the first-quarter 2012 total. During this quarter, four exploratory wells and 248 development wells were completed. Of the 244 production wells completed, 216 produced oil and gas, 24 were gas/condensate, and four were dry gas. During first-quarter 2013, crude oil production averaged 2.544 MMbpd, a 0.1% increase in volume over the first-quarter 2012 rate. The most important factors in the production increase were wells in the Ku-Maloob-Zaap, Abakatun-Pol-Chuc, Veracruz, Gulf of Mexico Tertiary Oil, and Burgos fields. The fields made up for production declines in Samaria-Luna, Cantarell and Litoral de Tabasco fields. WO



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AS PLAY EXTENDS BEYOND CORE

JIM REDDEN, Contributing Editor

Just as the Eagle Ford shale is poised to become the nation's premier onshore liquids producer, operators continue to re-delineate the South Texas play, turning their attention outward, and downward, in the hunt for prospects that extend beyond its 13-county core.

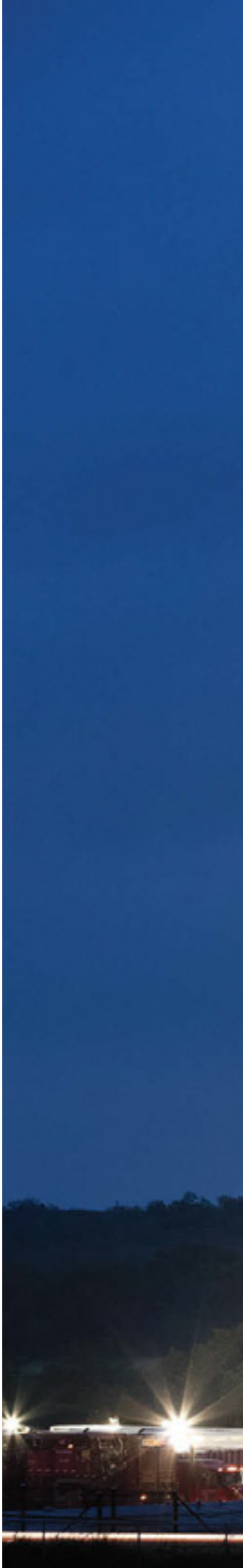
Much of the buzz, of late, has centered on the play's eastern expansion, where the Eagle Ford intersects the prolific Woodbine sandstone, the celebrated reservoir for the seemingly ageless East Texas field. As the so-called Eaglebine continues to emerge, the triple-window Eagle Ford also is serving as the springboard for a reawakening of sorts for the underlying Pearsall shale, which operators had largely abandoned, when gas prices collapsed. Farther to the south, some operators are looking with cautious optimism at Mexico's new presidential administration, which they believe could finally open the doors to more U.S. participation in exploiting potential Eagle Ford reserves across the border.

For the time being, however, activity for the most part continues to focus on the fairway of the Eagle Ford that, as currently delineated, stretches 50 mi wide and 400 mi long from the southernmost portion of Texas to the east. The formation produces natural gas, condensate, oil and NGLs, with margins that have been described as more favorable than other shale plays. As of July 22, Baker Hughes listed 233 rigs active in the core counties, compared to 250 at the same time last year—a decline attributed in no small part to increased emphasis on more rig-efficient pad drilling.

Offsetting the slight drop in the rig count is a year-on-year increase in the drilling permits issued by the Texas Railroad Commission (TRCC), the state's chief regulator, **Fig.1.** A survey of the 13-county core shows the TRCC approving 3,453 drilling permits between Jan. 1 and July 8, a 12.7% increase, compared to the 3,064 permits issued for the like period last year.

BAKKEN IN THE CROSSHAIRS

While there seems to be general agreement that the Eagle Ford will supplant North Dakota's Bakken shale as the nation's top unconventional liquids producer sooner, rather than later, what is less clear-cut is the precise volume that South Texas





A state-of-the-art H&P FlexRig 5, working for BHP in its Black Hawk field. Courtesy of BHP Billiton Petroleum.

operators are putting in the production stream, **Fig. 2.** The latest data from the TRCC show oil production of 536,117 bpd between January and April, compared to 384, 631 bpd for all of 2012. For the same period, TRCC documented production of 107,958 bpd and 2,141 MMcfd, which likewise, promises to surpass last year's aggregate total.

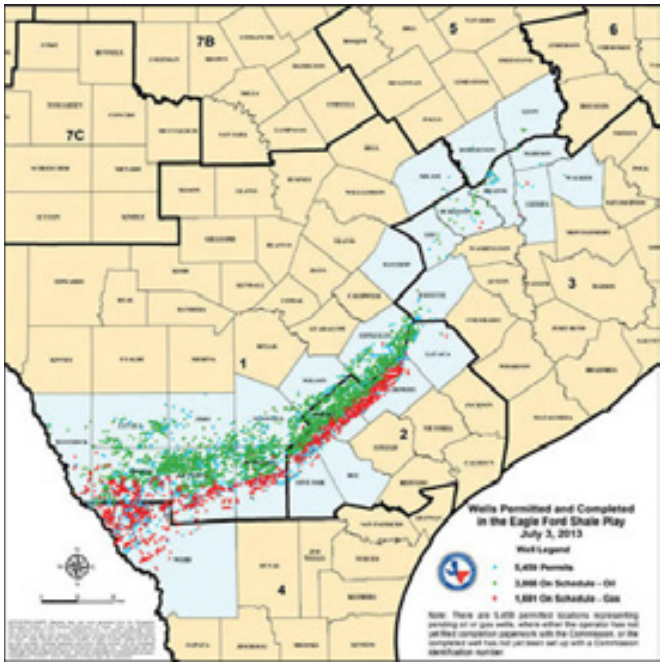
Veteran shale observer Gene Powell, publisher and editor of *The Powell Shale Digest*, and others contend that the TRCC consistently reports lower production, by not including its "pending file" in the overall mix, which comprises some 20% of Eagle Ford production. Moreover, the TRCC, Powell says, does not report condensate from gas wells as oil or, unlike other state agencies, record casinghead gas in the cumulative natural gas production tally. All this means a shortfall of approximately 121,825 boed from the reported numbers, Powell says.

Consequently, while TRCC reports aggregate January-to-April oil and condensate production of 643,830 boed, on June 25 Powell reported that his well-by-well research shows average production of 765,655 boed through March. By comparison, the North Dakota Department of Mineral Resources (DMR) said that the state's oil and gas production reached a milestone in May with a record 810,129 bpd and 900 MMcfd, respectively.

Powell's assertion was echoed by RBC Capital Markets analyst Scott Hanold, who, in a client note on May 29, said that the TRCC production numbers are a bit off-base. "While the trend is correct, we believe actual production in the Eagle Ford is higher than what is being reported," Hanold said.

Regardless, now-retired Mark Papa, former CEO of EOG Resources, the premier producer in the Eagle Ford, said in early May that U.S. shale oil supremacy boils down to a two-play race, and he has no doubt as to who will very soon cross the finish line first. "We think there are only two major driving forces of the U.S. oil growth: the Bakken and the Eagle Ford. The Eagle Ford is going to surpass the Bakken, likely this year, with the biggest oil growth rate," he said.

Fig. 1. Wells permitted and completed within the Eagle Ford fairway, as of July 3. Source: Texas Railroad Commission.

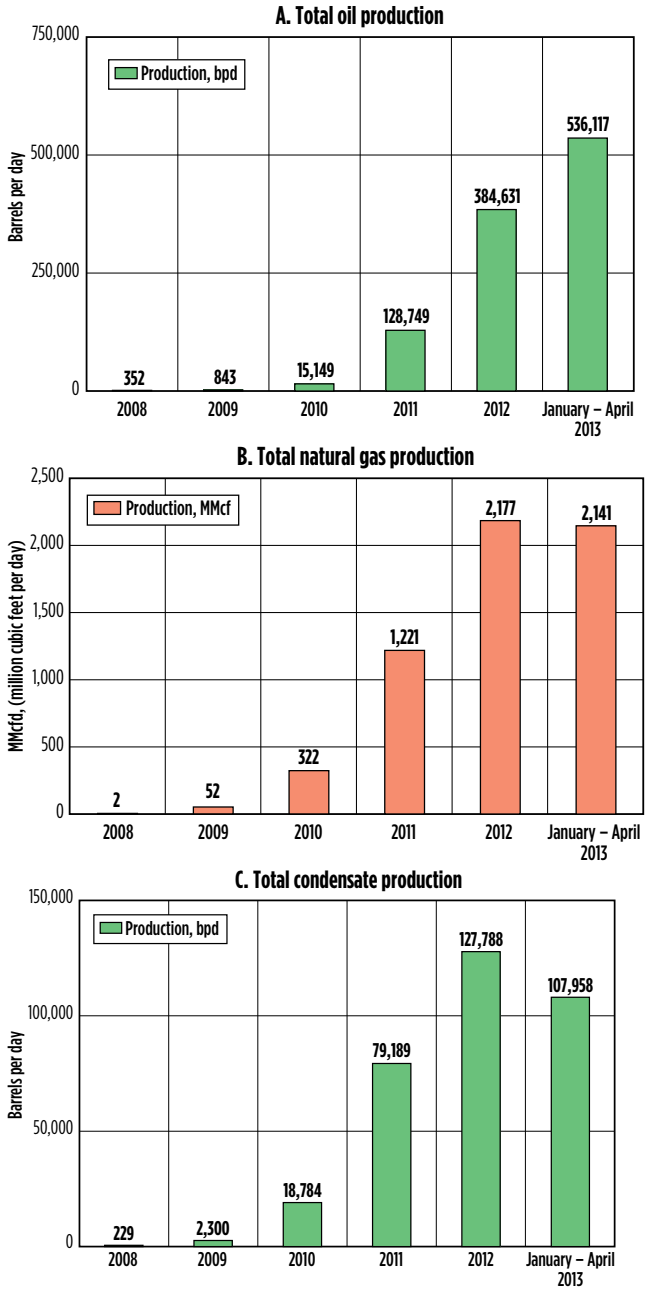


VALUE-RICH PLAY

The Cretaceous carbonate-rich Eagle Ford shale is defined as the world-class source rock for the overlying and heavily explored Austin Chalk formation, as well as the East Texas Woodbine field. The Eagle Ford, which overlies the Buda Limestone, and the Pearsall shale, has well-defined oil, wet gas and dry gas windows. Setting it apart from other North American shales, the formation has an average thickness of 250 ft, with some sections as thick as 330 ft.

In a research report released last summer, IHS handicapped the Eagle Ford-Bakken race, in favor of the former. IHS Director of Equity Research Andrew Byrne concluded that, on average, Eagle Ford wells out-produce their Bakken counterparts "by a margin of two to one." He predicted that the value inherent in

Fig. 2. Eagle Ford oil, natural gas and condensate production figures to April 2013. Source: Texas Railroad Commission.



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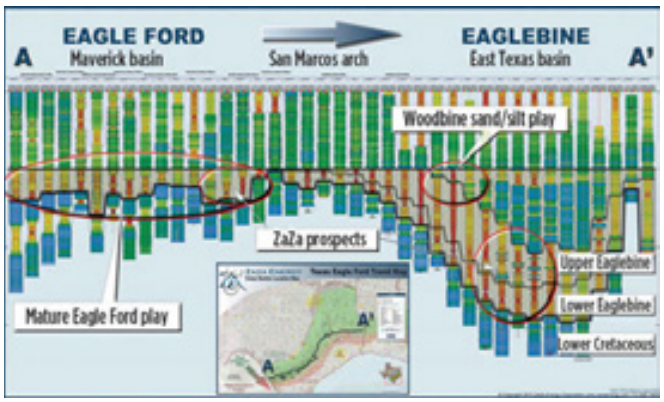
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Fig. 3. Cross-section of the Eagle Ford-Woodbine intersection. Source: ZaZa Energy



the play would accelerate acquisition and mergers, particularly with properties held by the smaller operators.

"You go through the initial land speculation stage, where the plays are occupied and dominated by a lot of smaller E&P companies. But then, when you get to the highly capital-intensive development stage, it makes lot of sense for these very small E&Ps to sell out to larger, better capitalized players," Byrne said.

During the past year, both small and not-so-small operators saw a prime opportunity to cash-in while asset values were nearing an apex. Chesapeake was one of the latest to take advantage of the increased value, selling off about 55,000 net acres that it held in the northern counties of Zavala, Dimmit, LaSalle and Frio, to suddenly aggressive Exco Resources. Exco also acquired Chesapeake's interest in 9,600 net acres in the Haynesville shale, with the combined sale netting the Oklahoma City, Okla., operator $1 billion.

Chesapeake retained ownership of around 435,000 net acres and drilled 91 new Eagle Ford wells in the first quarter. Chesapeake reported production of 75,000 boed in its Eagle Ford holdings during the first quarter, representing a 225% year-on-year increase.

In other recent acquisitions, Penn Virginia Corp. in April reached an agreement to acquire around 19,000 net acres held by Magnum Hunter Resources for $401 million. The estimated net production from the acreage in February was reported as roughly 3,200 boed. Magnum Hunter told *The Wall Street Journal* on April 3 that it will hold onto about 7,000 net acres in Fayette, Lee and Atascosa counties. Magnum Hunter has joined forces with Marathon Oil in a Pearsall shale well in Atascosa County.

On March 18, Houston's Sanchez Energy Corp. executed a definitive agreement with Hess Corp. to acquire some 43,000 net acres in Dimmit, Frio, LaSalle and Zavala counties for $265 million in cash. The acquired acreage holds proved reserves of approximately 13.4 MMboe, with current production of 4,500 boed. In July, Sanchez subsidiary SN Marquis snapped up a bargain with its $28.8-million acquisition of 10,300 net acres held by ZaZa Energy within its Moulton prospect in Fayette, Lavaca and Gonzales counties. In late March, ZaZa Energy formed a joint venture with EOG to explore Eaglebine prospects.

NEXT TARGET: EAGLEBINE

Over the past year, interest has intensified on a chunk of the Eagle Ford that overlies the Woodbine formation, a mixture of sandstone and marine shale in the East Texas basin. Singularly, the Woodbine, the well known reservoir for the still-producing East Texas field discovered in 1930, has been developed conventionally for several decades, but where leases so permit, operators now are focusing on redeveloping the play horizontally by tapping into the underlying Eagle Ford and in a single-wellbore completion.

Known colloquially as the Eaglebine, activity in the rapidly emerging play is centered primarily in the East Texas counties of Madison, Brazos and Leon, and, to a lesser extent, Grimes, Walker and Milam, **Fig. 3.** While the TRCC online W1 permit query does not record Eaglebine wells per se, an examination of the horizontal drilling permits issued for those counties suggests the prospective Eaglebine is quickly gaining operator favor. Between January and July 12, the TRCC issued an aggregate 174 new horizontal drilling permits in the targeted counties, compared to 92 for the same six-month period last year. To further put the suddenly increased interest in perspective, a total 130 horizontal well permits were issued for those six counties during 2011.

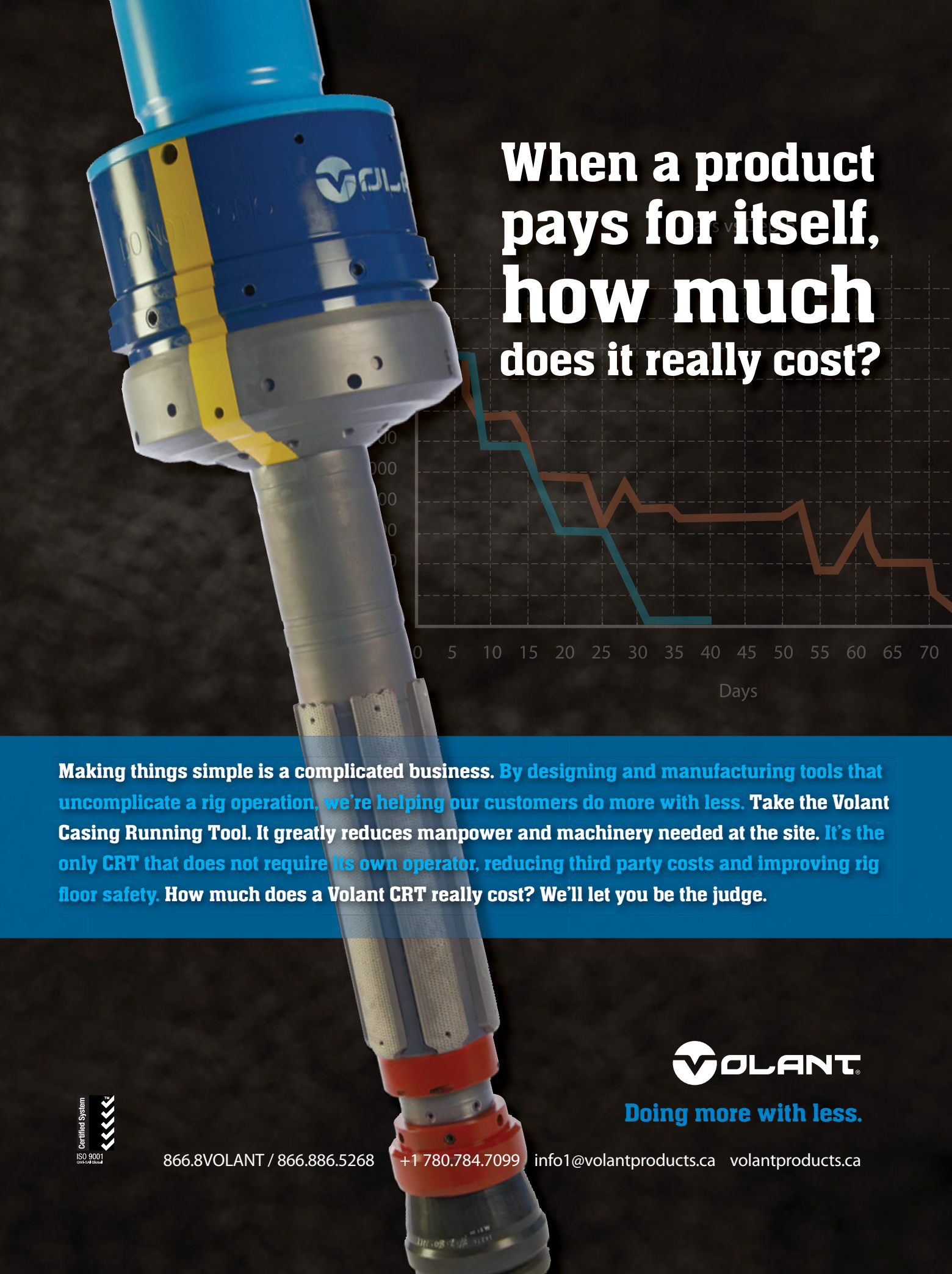
As the eastern extension of the Eagle Ford is in the very earliest stages of its emergence, scant well data are available. "We're testing some concepts over there. But, we've really not thought much about that, and are not really prepared to talk much about that kind of play at this point," new EOG CEO William R. Thomas, who replaced Papa upon his retirement on July 1, told analysts during an August earnings call. Nevertheless, in late March, EOG signed a joint exploration and development agreement with ZaZa Energy that covers the 73,000 net acres held by the latter in Walker, Grimes, Madison, Trinity and Montgomery counties.

For now, Houston's Halcón Resources takes top billing as the biggest cheerleader of the Eaglebine. Halcón is essentially a recreation of the late Petrohawk, which is largely credited with launching the Eagle Ford. BHP Billiton Petroleum acquired Petrohawk in July 2011, and that November, former chairman Floyd Wilson created Halcón, which now holds roughly 235,000 acres across East Texas that the operator says is prospective for the Woodbine, Eagle Ford and other formations. As of July, Halcón had nine producing wells in its acreage. This year, the firm plans to operate five to seven rigs, and spend approximately $490 million on drilling and completions.

Denver's SM Energy is one of the few to release specific well results, telling investors in April that its first horizontal Eaglebine well in San Jacinto County flowed at an initial 24-hr production (IP) rate of 740 boed, at 1,520 psig casing pressure on a 27/64-in., choke. At the same time, the independent announced that it has increased its East Texas acreage position to some 105,000 net acres and continues to actively lease "in this exciting play."

PEARSALL REAWAKENED?

Meanwhile, the gas-prone Pearsall formation, that lies at depths between 7,000 ft to 12,000 ft beneath the Eagle Ford and Buda formations, and traverses a large swath of the South Texas Maverick basin, is starting to breathe new life, spurred in no small part by a major acquisition last summer. All of the recent Pearsall wells reported are being drilled by operators holding overlying Eagle Ford acreage positions, where lease depth severance provisions allow for testing the deeper horizon. Historically, a number of wells were drilled conventionally in the shale-like Pearsall formation, but it was largely ignored after gas prices tanked, though some later wells had shown attractive oil shows, which has helped to inspire the latest turn in activity.


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Some eyebrows were raised in July 2012, when Cabot Oil and Gas sold a 35% non-operated working interest in 50,000 net Pearsall acres to a U.S. subsidiary of Japan's Osaka Gas for $250 million, **Fig. 4.** The acquisition of the Pearsall acres, which are spread out between Atascosa, Frio, LaSalle and Zavala counties, does not affect the 100% interest that Cabot holds in more than 60,000 net acres in the overlying Eagle Ford oil window.

During a first-quarter earnings conference call, Cabot Chairman, CEO and President Dan Dinges said that the operator plans to run up to three rigs and drill 15 horizontal Pearsall wells in 2013. To date, Cabot has nine producing Pearsall wells, he said, with average IP of 600 boed. "The Pearsall is still a young play and remains a science project for us," Dinges told analysts. "We have a thick hydrocarbon column, and continue to work on all aspects of drilling and completing a cost-effective well."

In May, Murphy Oil Corp. was to begin fracing operations on the first of two Pearsall wells that it intends to complete in the first half. The well was to be completed with a 2,000-ft lateral. Murphy holds more than 158,000 net acres over the Eagle Ford, including some 48,000 acres prospective for the Pearsall.

MEXICO ON THE HUNT

Mexico, meanwhile, recently announced its first-ever shale gas production from an Eagle Ford well, drilled directly across the border in the Burgos basin. In a first-quarter earnings report issued on April 26, state-owned Pemex said the Chucla 1 well recorded IP of 1.9 MMcfgd and 24 boed of oil and condensate, and "confirmed the existence of hydrocarbons in the Eagle Ford formation" of Mexico. Pemex said it continues to evaluate the production potential of shale resources in Mexico through the Chucla 1 well. Energy Minister Pedro Joaquin Coldwell told Reuters on May 8 that Pemex plans to drill up to 10 shale wells this year to further investigate its potential reserves.

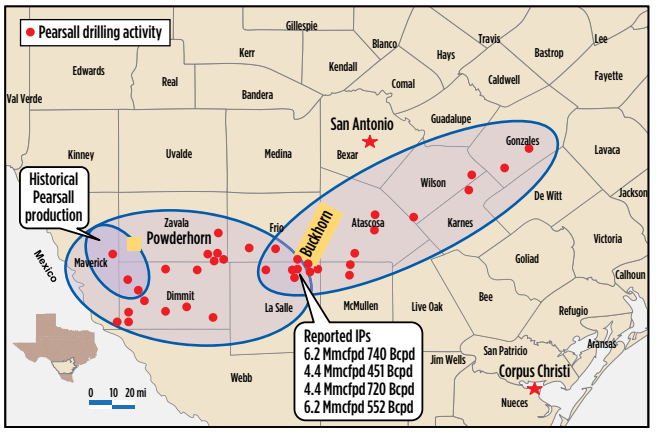
Mexico has been slow to exploit its recoverable shale gas reserves that the U.S. Energy Information Administration (EIA) estimates at 681 Tcf.

While a ranking official of the U.S. Department of Energy (DOE) says Mexico's neighbor is more than willing to lend a hand, the nation must first relax the ultra-nationalistic policies of Pemex, which has kept a firm lid on E&P rights. Some, however, are cautiously optimistic that the administration of recently elected Mexican President Enrique Peña Nieto may sufficiently liberalize policies to clear the way for more international cooperation.

"We are very interested in working with our colleagues in the government of Mexico to put in pathways for the better development of that resource," Christopher Smith, DOE acting assistant secretary for fossil energy, said in May 2013 during the Offshore Technology Conference. "We are taking steps to create the right types of collaboration, to ensure we develop that play in a way that is efficient and environmentally sound."

In the meantime, Houston's NET Midstream said it is installing a 124-mi pipeline that will deliver Eagle Ford gas to the growing Mexican market. The pipeline is expected to go online in December 2014, delivering up to 2.1 Bcfgd across the border.

Fig. 4. Cabot Oil and Gas holdings within the Pearsall shale. Source: Cabot Oil and Gas.



EOG Resources holds a commanding 639,000-net-acre position and reigns as the largest oil producer in the Eagle Ford. At the end of the first quarter, the Houston-based independent produced an estimated net 153,000 boed and had increased by 38% the potential reserves in its properties.

EOG is running 25 rigs and plans to drill 425 net wells this year, compared to year-end 2012 that had the company operating 23 active rigs and drilling 305 net wells. EOG, which has reduced its per-well drilling time to less than 13 days, says its inventory will provide 12 drilling years, based on current technology.

Of its cumulative leasehold, 569,000 net acres are contained within the oil window, where EOG consistently has recorded some of the play's highest IP rates. In a recent filing with the TRCC, EOG recorded a play-high 7,513 bopd during an initial 24-hr test of its Burrows Unit 5H in Gonzales County, which was completed in mid-April. In the first quarter, EOG documented 18 wells with IP of more than 2,500 bopd, and nine with more than 3,500-bopd initial flowrates.

Anadarko Petroleum, which holds 400,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, delivered a net sales volume of 42,200 boed during the first quarter, representing a 55% increase over the identical 2012 reporting period. The Woodlands, Texas operator recorded total liquids volumes of 28,000 bpd during the quarter—a 60% jump from the first quarter of last year. Anadarko operated an average of eight rigs and drilled 70 wells during the quarter.

BHP Billiton Petroleum controls 341,000 net acres, where it operated 31 rigs in the first quarter in its Hawkville and Black Hawk fields, compared to 24 active rigs in late May 2012. For its fiscal year ended June 30, BHP said its 2012 U.S. onshore drilling and development expenditure totaled $4.8 billion, more than 80% of which was directed toward its Eagle Ford play and Permian basin holdings. The operator says that with drilling efficiency improvements it expects to reduce its average count in fiscal year 2014. Owing to a management re-organization spurred by the July retirement of CEO J. Michael Yeager, no specific 2013 drilling plans have yet been released. Tim Cutt,

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president of the Australian mining giant's diamond division, was tapped to replace Yeager.

Talisman Energy/Statoil control roughly 74,000 and 73,000 net acres, respectively, which since 2010, the two have developed in a 50-50 South Texas Joint Development Agreement (STJDA), in which the former had functioned as operator. Effective July 1, Statoil will assume operatorship of the eastern half of the total acreage, mainly comprising leases in Live Oak, Karnes, DeWitt and Bee counties, while its Canadian partner will continue to operate the western acreage, mostly in McMullen, La Salle and Dimmit counties. With its transition to partial operator, Statoil has taken control of three of the seven active rigs running this year under the STJDA umbrella and will assume responsibility for producing wells, facilities, pipelines and infrastructure. At the end of 2012, the JV partners each recorded net production of nearly 21,000 boed.

ConocoPhillips, which completed its first year as an independent operator, holds 227,000 net acres, mostly in the liquids-rich core that it claims holds a 1.8-Bboe potential resource base. Executive Vice President of Exploration and Production Matt Fox told analysts that Eagle Ford production stands at 120,000 bopd, up slightly from 100,000 bopd at the end of 2012.

The operator said it is nearing the full-field development phase of its Eagle Ford program and expects to add around 130,000 boed to its production stream by 2017. ConocoPhillips ran an average of 16 rigs last year, but the active count is

Fig. 5. A ConocoPhillips-operated rig drilling within the estimated 227,000 net acres it holds in the Eagle Ford. Courtesy of ConocoPhillips.



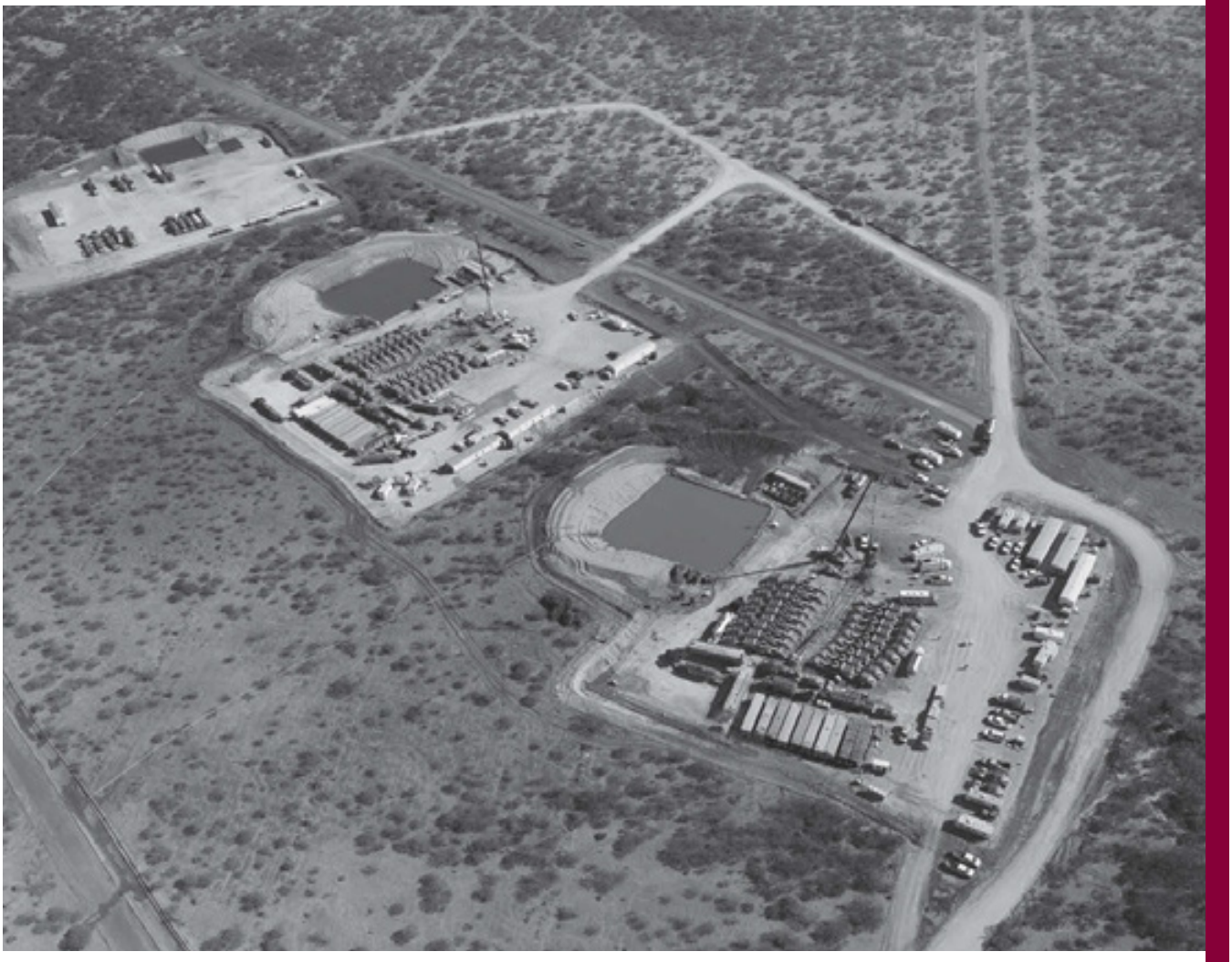


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expected to be lower this year, as the operator moves to pad drilling, **Fig. 5.**

Marathon Oil, with the 2012 acquisition of Paloma Partners II, now holds an estimated 317,000-net-acre-position in the Eagle Ford, where its net production increased to 72,000 boed in the first quarter, representing a 22% jump over year-end 2012 output. During the first quarter, Marathon drilled 76 gross wells, while placing 68 gross wells into the sales stream.

Marathon says its "spud-to-spud performance" has improved from 28 days in the first quarter to 18 days over the first three months of this year, with further declines expected with the acceleration of pad drilling. The operator says it has also begun drilling wells in the Austin Chalk and Pearsall formations "to further test the resource potential of these horizons."

Forest Oil formalized a 50-50 partnership with Schlumberger in April, and immediately afterwards, released details of an accelerated 2013 development campaign for its 27,500-net-acre leasehold. In conjunction with Schlumberger Production Management (SPM), the Denver independent will be operating four rigs by the third quarter and plans to drill 60 gross wells this year and 80 next year.

Forest said it is moving toward producing an average 6,500 boed in 2014, up from the 1,600 boed it produced last year from its Eagle Ford holdings. Under terms of the unique joint venture, SPM will pay a $90-million drilling carry in the form of future drilling and completion services, as well as related development capital, giving it a 50% equity. According to Forest President and CEO Patrick McDonald, upon completion of the phased contribution of the drilling carry, Forest and SPM will participate in future drilling on a 50/50 basis.

SM Energy has an estimated 144,804 net acres under lease in six operating areas spread throughout the play. The independent's operated net production averaged 51,800 boed in the first quarter, a 15% sequential increase over fourth-quarter 2012 production of 45,200 boed. During 2013's first quarter, SM Energy operated five rigs and completed 28 wells.

Pioneer Natural Resources and its minority partner India's Reliance Industries drilled 37 wells in the first quarter within its estimated 212,000-net-acre lease holding. The joint venture plans to run a 10-rig drilling program and complete at least 130 wells this year. Pioneer said 80% of its drilling activity this year will be conducted from pads, up from 45% in 2012, allowing it to reduce its rig count from the 12 units it averaged last year. Pioneer increased production to 37,000 boed in the first quarter from 23,000 boed in the identical quarter last year.

Swift Energy held 75,892 net acres in the Eagle Ford, at the end of 2012. During 2012, Swift drilled 55 successful development wells in South Texas. During 2013, Swift has scaled back its drilling, due to "the low-pricing environment for natural gas and NGLs." However, Swift continues to focus on drilling liquids-rich wells in identified brittle areas of the Eagle Ford. The initial plan for 2013 included 25 Eagle Ford wells and six Olmos wells. As of first-quarter 2013, the company had already completed nine operated wells, including four Eagle Ford wells and two Olmos wells in McMullen County, and three Eagle Ford wells in La Salle County. WO







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This year's conference will focus on **"Frontiers of Shale Technology,"** and the two-day, dual-track program will feature sessions geared to discussing the major technical problems facing operators and the cutting-edge solutions that need to be employed to solve them.

In addition, specific case histories and the latest details about active plays, like Eagle Ford, Haynesville and Bakken, will be available throughout various presentations. Following a multi-track panel discussion, there will be a Q&A providing attendees with the opportunity to engage in a live, real-world discourse concerning the shale energy industry.

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REGIONAL REPORT

NORTH WEST EUROPE

A new round of frontier exploration hot spots challenges the industry's technical prowess in several offshore areas.

ELIZABETH LLOYD and ANDRÉ SHARMA, Deloitte's Petroleum Services Group

The northern basins of the Barents Sea, the West of Shetlands, and the deepwater basins along the Irish coast, are all becoming areas of increased exploration and licensing activity, as companies seek to explore frontier areas. These new areas of interest, however, come with harsher operating environments, lack of infrastructure, and technical challenges.

Future, successful exploration activity in these three frontier areas may revive interest in North West Europe and attract operators and companies that are exploring other frontier parts of the world.

BARENTS SEA

The Arctic Continental Shelf contains some of the least-explored basins on Earth. The Norwegian Barents Sea is one of the few areas of the Arctic Circle with a year-round, ice-free zone. It is attracting interest, with a recent increase in both drilling and licensing activity. The Barents Sea has the potential to become a successful oil and gas region with significant resources yet to be discovered. Total undiscovered resources in the Barents Sea are now estimated to amount to 7.9 Bboe, according to the Norwegian Petroleum Directorate (NPD), and represents 42% of all undiscovered resources offshore Norway.

Compared to other Norwegian waters, the Barents Sea is underexplored. In total, approximately 80 exploration wells have been drilled in this region, compared to almost 200 in the Norwegian Sea and over 700 in the North Sea.

Geological exploration of the Norwegian sector of the Barents Sea started with seismic surveys in the 1970s. A decade later, in 1980, exploratory drilling commenced, when both Norsk Hydro and Statoil spudded wells, both of which were completed with hydrocarbon shows.

Exploration activity in the area has increased since 2005. Drilling success has also increased, and 50% of the wells spudded since 2005 have successfully discovered hydrocarbons. Statoil has operated 11 of the wells; Eni has drilled four; and Lundin has spudded two.

In 2008, Statoil targeted the Obesum prospect, and discovered oil and gas in Middle Triassic sandstones. However, it was deemed to be too small to prove com-

Crew members (left) work on an enclosed drill floor, on the *West Hercules* semisubmersible, contracted by Statoil to drill prospects northeast of the Skrugard (now Johan Castberg) and Havis discoveries in the Barents Sea. Statoil photo by Ole Jargan Bratland. Clair field (center) in the West of Shetlands area is now the UK's largest oil field, and it is undergoing a second phase of development that includes another platform. Photo courtesy of BP. After a two-year period of no exploration wells offshore Ireland, the *Eirik Raude* semisubmersible has been drilling a wildcat on the Dunquin prospect for Exxon Mobil this summer. Photo courtesy of Ocean Rig.



mercial at the time. In the same license, Statoil also discovered gas from a wildcat well on the Middle Triassic Caurus prospect. Caurus has estimated reserves of 155 MMboe to 375 MMboe. In 2011, Total discovered gas in the Middle Triassic Kobbe formation on its Norvarg prospect, which has also now been appraised successfully. Lundin discovered gas at its Skalle prospect, with the first well drilled in license PL438. In 2012, Eni discovered gas in the Cretaceous Knurr formation, and in the Jurassic Stø formation at the Salina prospect.

Discoveries made recently have proven plays as well as the existence of working hydrocarbon systems in the Barents Sea that have helped generate renewed interest in the region. However, recent interest in the Barents Sea can be attributed largely to Statoil's success in license PL532, and the Skrugard and Havis oil discoveries made in 2011 and 2012, respectively, **Fig. 1.** These finds were the largest, and first, commercial finds in the Barents Sea for a decade. The Skrugard (renamed Johan Castberg in April 2013) and Havis twin discoveries have combined recoverable resources estimated at between 400 MMboe and 600 MMboe. The field is approximately 100 km north of the Snøhvit producing field and 150 km from Goliat field, which is under development. Statoil expects to have a field development plan for Johan Castberg in place in 2014. Production is anticipated to start in 2018.

Goliat field was the first oil find to be developed in the Barents Sea. The field was discovered in 2000, and the plan for development was approved in June 2009. The operator, Eni Norge, plans to bring the field onstream before the end of 2014. Goliat is expected to produce for at least 15 years. It has estimated recoverable oil reserves of 174 MMbbl of oil. Total development costs are roughly $5.01 billion.

Acreage in frontier regions offshore Norway, such as the Barents Sea, is awarded through licensing rounds held approximately every second year. During these rounds, acreage is offered in immature areas of the Norwegian Continental Shelf (NCS) to promote exploration.

The most recent licensing round to cover the Barents Sea, the 22nd Round, awarded blocks in June 2013, **Fig. 2.** Twenty new licenses were granted in the Barents Sea. The awards resulted in 29 different companies being offered participating interests in various licenses, 14 of which were also offered operatorships. This was the most successful licensing round for the Barents Sea, and it has increased the number to over 70. The companies being offered operatorship of licenses in this region include a mix of majors, such as Shell, Total and ConocoPhillips, and independent oil companies, including RWE, E.ON and Edison. This mix has increased the number of companies acting as operator in the Barents Sea, proving the region's attractiveness.

For the first time, awards have also been made to two Russian companies. Lukoil and Rosneft have been offered interests in two, and one licenses, respectively.

Elsewhere in the Arctic Circle portion of North West Europe, activity has increased in recent years. At the end of 2012, **Iceland** awarded its first-ever hydrocarbon exploration licenses. Twelve blocks were awarded as two separate licenses to operators Ithaca Energy and Faroe Petroleum. In addition, recent news suggests that CNOOC will also be awarded acreage, later in 2013.

In May 2013, Exxon Mobil increased its interest in license L016, offshore the **Faroe Islands**. License L016 contains a large, four-way dip structure called Kúlubøkan, with potential at various stratigraphic levels. A 3D seismic survey was acquired during 2012, to further

Fig. 1. The *Polar Pioneer* semisubmersible drilled the Skrugard discovery. Statoil photo by Harald Pettersen.



Fig. 3. Statoil has contracted the *West Hercules* semisubmersible to drill back-to-back exploration wells, northeast of two other Barents Sea discoveries.



Fig. 2. Twenty new licenses were awarded in June 2013 to 29 companies in Norway's 22nd Licensing Round.

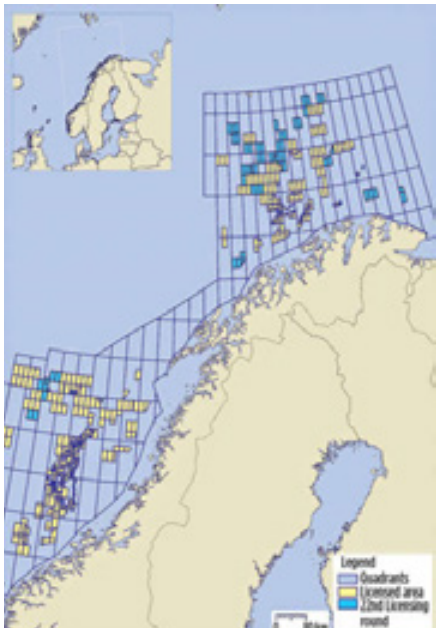
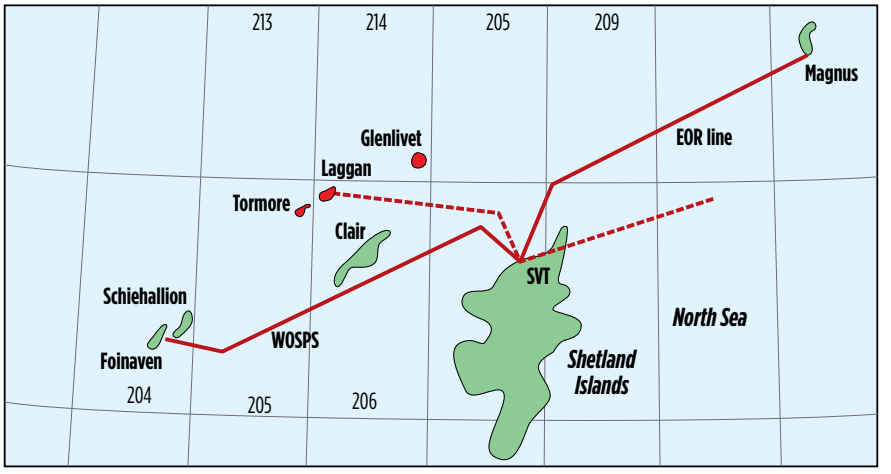


Fig. 4. The West of Shetlands area is a petroleum province with a proven track record, featuring several significant fields, including Clair, the UK's largest.



the understanding of the structure. The license partners are expected to make a decision on drilling by the end of 2014. The last well to be drilled in Faroese waters was in 2012, when Statoil drilled exploration well 6104/21-2 on the Brugdan II prospect. Due to concerns over bad weather, Faroese authorities ordered a suspension of the well until the end of 2013.

Overall, Statoil is the most active player in the Barents Sea, with an extensive exploratory drilling campaign to date. It includes nine planned exploration wells over the next two years. Statoil is targeting four prospects northeast of the Skrugard and Havis discoveries, with back-to-back exploration drilling conducted by the drillship, *West Hercules*, **Fig. 3.** Upon completion of this drilling campaign, Statoil plans to select a development concept for the area, targeting first oil in 2018.

Both Statoil and Lundin have exploration wells planned in the Barents Sea over the next few years. Lundin plans to drill two exploration wells in 2013—one on PL492, the Gohta prospect, which has gross prospective resources of 226 MMboe, and one on PL659, the Langlitinden prospect, which has gross prospective resources 155 MMboe to 375 MMboe. In addition to their current drilling campaign, Statoil and partners have plans to also drill the Apollo and Atlantis prospects in license PL615, and the Wisting Central prospect, in some of the most northerly licenses in the Barents Sea.

Given the ongoing work commitments from the recent 22nd Round, as well as further exploration drilling already planned in this region, interest is expected to continue to rise.

WEST OF SHETLANDS

The North Sea is considered by many to be a mature region in terms of oil and gas exploration activity. Infrastructure is well-established, and the region has had a long, successful history of exploration. However, the West of Shetland basin is



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an area within the North Sea that is still considered frontier. West of Shetlands water depths are much greater than those in the gas-prone southern North Sea province, and coupled with a harsh winter climate and less established infrastructure, exploration activity remains relatively sparse. The West of Shetlands is a proven petroleum basin, with production from fields that include Clair, Foinhaven and Schiehallion, **Fig. 4.** The UK government introduced a new class of field allowance in 2012, targeting deepwater fields in the West of Shetlands, to encourage further frontier exploration in this area.

Since exploration in the West of Shetlands began in 1972, there have been 171 exploration wells spudded, 26% (45 out of 171) of which have been completed as successful hydrocarbon discoveries. Drilling activity has been increasing since 2006—last year, 10 wells were spudded in the region. Over the last 10 years, 29 exploration wells have been drilled.

In recent years, a number of new discoveries have been struck. In 2008, Hess discovered the Amos oil accumulation, and in 2009, Dong discovered gas at its Glenlivet prospect. It has since been evaluated successfully by two appraisal wells that have confirmed an excellent-quality, gas-bearing reservoir. In 2011, Faroe Petroleum hit a discovery at its Fulla prospect, discovering oil in Clair and Whiting reservoir sands. During 2013, BP discovered hydrocarbons at its North Uist prospect. BP's North Uist exploration well has been one of the most high-profile exploration campaigns in the West of Shetlands basin in recent years. The parent well, targeting the Upper Jurassic North Uist prospect, and its five sidetracks were drilled over a 12-month period. The well was completed as a gas-condensate discovery in March 2013 and has proved another working hydrocarbon system in the basin. It should encourage further exploration in the area.

Competition for West of Shetlands acreage has been fierce in recent years. Recent UKCS licensing activity has resulted in the doubling of total, licensed acreage in the West of Shetlands. Prior to the 27th UK Offshore Licensing Round, approximately 90 blocks and portions of blocks had been licensed. Following the results of the 27th Licensing Round an-

nounced in October 2012, 80 new blocks were licensed, bringing the total licensed blocks to almost 170.

West of Shetland licenses are operated by a variety of companies, including a mix of majors, super-majors and smaller independent companies. BP operates the largest number of licenses at 10, while Total and Dong each operate nine, making these companies the most dominant in the region.

Hurricane Exploration operates three licenses in the West of Shetlands, covering 18 blocks and partial blocks. Hurricane Exploration's strategy differs from that of other companies operating in the region. Hurricane actively explores fractured basement reservoirs, in a search for significant untapped resources, and has had some recent success. In 2009, Hurricane drilled the Lancaster prospect and discovered oil in its fractured basement rocks, with estimated 2C contingent resources of 207 MMboe. In 2010, Hurricane drilled its second basement prospect, Whirlwind, and found hydrocarbons of a similar volume to those at Lancaster. In addition, Hurricane has identified a well location on a third basement prospect, Lincoln, and work is underway on the Typhoon prospect.

The West of Shetlands is also home to the UK's largest oil field, Clair. It is 75 km west of the Shetland Islands, in water depths of up to 150 m and extending over an area of 220 sq km. Clair is the UK's largest hydrocarbon resource, with initial, in-place volumes across the entire field estimated at more than 7 Bboe.

The Clair reservoir was discovered in 1977 by the 206/8-1a exploration well, which penetrated an oil column in a sequence of Devonian to Carboniferous sandstones. Subsequent to extensive appraisal activity, and following review of several development plans due to high costs, development of the field was finally approved in 2001. First oil was achieved in February 2005, and BP and its partners have produced approximately 90 MMboe.

BP has started the second phase of development, called the Clair Ridge project. It is designed to target the northern area. In March 2013, BP commenced a two-year appraisal program with plans to include at least five wells that will look at developing a third phase of Clair. The Clair Ridge project should begin production in 2016 and produce an estimated 640 MMbbl of oil over 40 years while providing a hub for future expansion.

A prospect that has been in the limelight in recent months, due to associated deal activity, has been the Ithaca Energy-operated Handcross prospect. The Handcross prospect lays across licenses P1631 and P1832, about 12 km east of the UK-Faroese border. In March 2013, RWE acquired a 20% interest in the prospect, while Edison in June 2013 acquired a 25% share, as Ithaca Energy farmed down its original 90% interest. Handcross is a Palaeocene channelized fan prospect, with estimated resources of approximately 115 MMboe. The prospect is close to the Suilven and Tornado discoveries, and 20 km from BP's Quad 204 redevelopment. A firm slot on the *Stena Carron* drillship (**Fig. 5**) has been contracted to drill an exploration well on Handcross, which is anticipated to spud during fourth-quarter 2013.

With continued successful drilling, and high levels of interest from a variety of companies, the West of Shetlands is likely to remain a hot spot with some exciting exploration activity to come.

IRELAND

According to the Irish Offshore Operator's Association (IOOA), only about 5% of the Irish offshore area is under license, **Fig. 6.** From 1970 to date, 146 exploration wells have been spudded by a number of different operators offshore Ireland. The IOOA states that the commercial success rate for Ireland is approximately one in 25. However, more recently, offshore Ireland is becoming a focus for IOCs. With ever-improving technology, higher oil prices and discoveries elsewhere on the Atlantic Margin, interest in the area's potential has grown recently. In 2012, five deals were announced in Ireland, all in the form of farm-ins. This was the same number that was reported in 2011. So far in 2013, eight farm-in offers or deals have been announced, with a number of independent companies entering the region, such as Cairn Energy and Kosmos Energy.

The fiscal terms for Irish offshore activity are favorable. The Irish government's corporation tax is 25%, no bonuses are due on the discovery of hydrocarbons,

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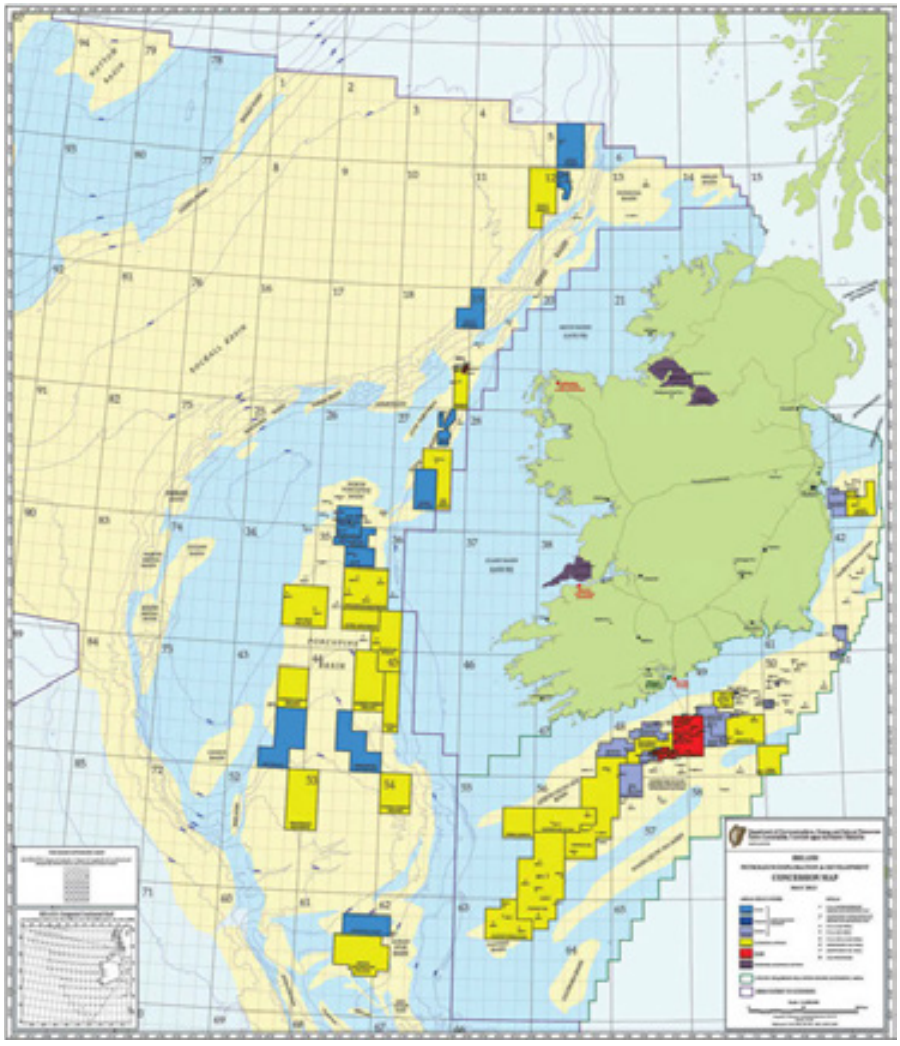
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Fig. 5. Ithaca Energy will employ the *Stena Carron* drillship to spud an exploration well on the Handcross prospect, east of the UK-Faroese border, in fourth-quarter 2013.



Fig. 6. A relatively small portion of Ireland's offshore area has been licensed. Map courtesy of Irish Department of Communications, Energy and Natural Resources.



and there are no royalty taxes or PSAs on new licenses.

Exploration results offshore Ireland have been mixed in recent years. Since 2008, there have only been six exploration wells spudded west of Ireland, in either the Rockall or Slyne-Erris Troughs or the Porcupine basin. In 2008, Shell targeted the West Dooish prospect in the Rockall Trough with well 12/2-2. However, the well failed to encounter any hydrocarbons, unlike the Dooish exploration well 12/2-1 to the east, which discovered gas/condensate in 2003. Also in 2008, Statoil drilled a well on the Cashel prospect, about 144 km southwest of the Dooish discovery in the Slyne-Erris Trough. However, it failed to encounter hydrocarbons.

The Serica-operated Bandon exploration well and its subsequent sidetrack discovered oil in 2009. The discovery was made in Jurassic Sherwood sands. Shell became active again in 2010, and tested an extension prospect northwest of Corrib gas field. The well proved to be unsuccessful. In 2011 and 2012, no exploration activity occurred offshore Ireland. In 2013, Exxon Mobil spudded the highly anticipated Dunquin exploration well off the southwestern coast, in the Porcupine basin. There has been great interest in the Porcupine basin recently, and the operators and partners that have become involved include Exxon Mobil, Cairn Energy, Antrim Energy Inc., Kosmos Energy, Europa Oil and Gas, Bluestack Energy, and Petrel Resources. For detailed information on activity in the Porcupine basin, please see the article by Contributing Editor Ian Lewis, immediately following this regional report.

A number of fields and discoveries offshore Ireland have proved to be commercially viable since the early 1970s, **Table 1.** Kinsale Head gas field was discovered in 1972. The well targeted the Lower Cretaceous Greensand and Wealden sandstones, and it tested gas at a rate of 12.4 MMcfgd from the Lower Cretaceous, with production beginning in 1978. Cairn Energy's Burren and Spanish Point discoveries lie in adjacent blocks in the Porcupine basin.

The Shell-operated Corrib gas field, on the west coast, was discovered in 1996. It represented the first commercial find offshore Ireland, since Kinsale Head in 1972. Following five successful appraisal



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wells drilled between 1998 and 2001, the field's development plan was approved in April 2002.

The Serica-operated 27/4-1 well in the Slyne basine was spudded during May 2009, to test the Bandon prospect. It reached a TD of 6,233 ft in the Sherwood sands. No gas was found; however, an oil accumulation in Jurassic sands was encountered, and a sidetrack well, 27/4-1Z, was drilled to confirm the discovery. The discovery of oil has opened a new play in the Slyne basin and enhanced the prospectivity of the blocks.

The Providence-operated Barryroe oil field underwent successful appraisal drilling in 2012. Previous operators had drilled five wells on the field, all of which logged hydrocarbon-bearing intervals, and three were flow-tested successfully. In 2011, having acquired a new 3D seismic survey over the field, Providence began drilling a sixth well on the field. In March 2012, the partners announced testing results from this well, which far exceeded the pre-drill expectations. This led to a substantial upgrade in field size to over 1 Bbbl of oil-in-place, with over 300 MMbbl (on a P50 basis) of recoverable oil. Providence and Lansdowne are planning the development concept. They began their farm-out campaign in first-half 2013, with drilling planned for 2014.

Eni has been given the go-ahead to shoot an 18,000-km, 2D seismic, full-fold program on the Irish Atlantic Margin this year. The survey is thought to be the largest regional seismic shoot, to date, offshore Ireland. The survey is designed to infill data gaps that exist, particularly in the southern Porcupine basin and Rockall Trough. It also will allow the Irish government to evaluate future licensing opportunities.

In the Rockall Trough and Slyne-Erris Trough, Serica Energy believes that there is a major resource opportunity with multi-Tcf gas potential. Muckish is analogous to the nearby gas-condensate-bearing Dooish structure drilled by Enterprise in 2002, which encountered a 214-m hydrocarbon column and has a gross P50 resource potential of 1.3 Tcf of gas and 85 MMbbl of condensate.

In the same basin, the Boyne and Liffey prospects are interpreted as two deeper Jurassic oil prospects, each with an underlying Triassic gas prospect in the Sherwood sandstone. Serica and partner RWE Dea plan to drill a well in 2014 and will begin a farm-out campaign in 2013.

On the southeast coast, Lansdowne Oil and Gas has a number of prospects in the Celtic Sea Graben system, with drilling expected to take place in 2013 and 2014. The Middleton prospect lies along a trend of inverted structures, along the northern margin of the basin that includes Ballycotton field. Amplitude brightening from fluid anomalies is interpreted as Greensand reservoirs, similar to those seen on seismic lines across Ballycotton. Middleton has been assessed as having potential P50 recoverable resources of 268 Bcf of gas.

The East Kinsale prospect lies to the southeast of Middleton, and a number of low-relief, anticlinal closures have been mapped, some of which may form extensions of the Old Head accumulation. A



TABLE 1. IRISH PETROLEUM LEASES - PRODUCTION

Lease	Commencement Date	Block No. ((p) = part block)	Area (km²)	Participants (* = Operator)	Interest, %
Offshore Petroleum Lease No. 1: Kinsale/ Ballycotton	7 May 1970	48/20, 48/25, 49/16, 49/21	1,003.03	PSE Kinsale Energy	100%
Corrib Petroleum Lease	15 November 2001	18/20 (p), 18/25 (p)	29.28	*Shell E&P Ireland,	45%
				Statoil Exploration (Ireland),	36.5%
				Vermilion Energy	18.5%
Seven Heads Petroleum Lease	13 November 2002	48/23 (p), 48/24 (p), 48/29 (p), 48/30 (p)	168.5	*PSE Seven Heads,	86.5%
				Island Oil and Gas Plc,	12.5%
				Sunningdale Oils (Ireland)	1%

NW-SE-trending, faulted anticline may form a separate structure, and this shows evidence of gas escape on seismic. To the north of Barryroe field, the Rosscarbery, Amergin and Eremon prospects are thought to have good potential. Rosscarbery is in LO 5/7, which also contains the Gally Head and Carrigaline gas discoveries, with potential for 86 Bcf of recoverable gas. Amergin and Eremon are two large structures mapped at the Jurassic level. Amergin has potential for 231 MMbbl of recoverable oil.

San Leon Energy has four offshore, Atlantic Margin licenses, and four offshore Celtic basin licenses. On the west coast of Ireland, San Leon operates all four licenses, covering an area of 2,880 sq km, which contain a number of prospects and leads. WO



ELIZABETH LLOYD is a senior oil and gas analyst for Deloitte's Petroleum Services Group in London. She monitors and tracks upstream activity, focusing on licensing and deal activity in North West Europe, and co-authors the *Weekly Service*, a newsletter covering industry news across the region. Ms. Lloyd joined Deloitte in 2011, initially working as an analyst for North Africa before focusing on analysis of North West Europe. She earned a BS degree, with Honors, in geology from the University of Bristol, and graduated from Imperial College, London, with an MS degree in petroleum geoscience during 2009. Email: elloyd@deloitte.co.uk



ANDRÉ SHARMA is an oil and gas analyst for Deloitte's Petroleum Services Group in London. He monitors and tracks upstream activity, focusing specifically on drilling activity in North West Europe, and co-authors the *Weekly Service*. Mr. Sharma earned a BS degree, with Honors, in geological sciences from the University of Leeds in 2009, and an MS degree in structural geology with geophysics, also from the same institution, a year later. He worked as a geophysicist at Petroleum Geo-Services before joining Deloitte. Email: andsharma@deloitte.co.uk



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Porcupine basin spikes fresh interest offshore Ireland

Spurred by liberal fiscal terms and recent drilling success, a greater number of firms are taking a fresh look at Ireland's largest exploration play.

IAN LEWIS, Contributing Editor, EAME

The chairman of the Irish Offshore Operators' Association (IOOA), Fergus Cahill, recently defended the relatively generous fiscal terms on offer to offshore explorers in Ireland, partly on the grounds that companies needed incentives to drill in a sector that, for all its touted potential, has a low success rate.

The mega-find that has been sought in parts of Atlantic acreage to the west of Ireland remains elusive. Cahill estimates that the commercial success rate for exploratory wells in Ireland is about one in 25, compared to around one in five in Norway. While around 200 wells have been drilled in Ireland over recent decades, only two relatively small commercial discoveries have been made—the Kinsale Head and Corrib gas fields—holding about 2.5 Tcf of gas reserves between them.

However, there is an intensification of interest in blocks within the Porcupine basin, to the west of the country in the Atlantic Ocean, from companies with some serious clout. This suggests that if there is enough oil and gas out there to make this a major new hydrocarbons province, we may be about to find out.

Driven by sustained high oil prices, and similarities between the geology of Ireland's Atlantic blocks and other areas of the Atlantic Margin where hydrocarbons have been discovered, a number of firms have bought licenses in the Porcupine basin and other acreage, in Ireland's most recent licensing rounds.

The probability of making a discovery in Ireland has increased over the last decade, to around one in three, but nothing found in that period has been deemed commercially viable. That may change. Providence Resources has been assessing the commerciality of its Barryroe discovery in the North Celtic Sea basin, just off the southern coast of Ireland, where a sixth well was successfully drilled in 2012. The field holds over 1 Bbbl of oil-in-place, with more than 300 MMbbl recoverable (2C). In addition to looking for a farm-in partner for that asset, Providence has been involved in several tracts in the Porcupine. Although the firm has farmed-out its operatorships and reduced its holdings, it still retains 32% of these tracts. For more details, see the Cairn Energy write-up in the "Other Operators" section.

News that Exxon Mobil had spudded the first well to be drilled in the Porcupine Basin for many years in April 2013 attracted considerable interest. However, the company said in July it had found mainly water plus residual traces of hydrocarbons and were plugging the well on their Dunquin North prospect.

Providence, one of Exxon's partners, reported that the primary target comprised a thick overpressured carbonate reservoir system. The well was terminated having drilled a total thickness of around 800 ft of massive porous carbonate reservoir. While analysis indicated the reservoir was water bearing, petrophysical log interpretation, elevated gas levels, and oil shows in sidewall cores over the upper 144-ft section of the reservoir suggested the presence of a possible residual oil column.

While Exxon Mobil said it had no further plans to drill in Irish waters, Providence said the outcome was potentially positive for its nearby Dunquin South prospect, given the signs of a working hydrocarbons system. It gave no indication of its plans for that acreage.

Fig. 1. Woodside Energy is one of the larger companies to jump into the Porcupine basin in the last several years, entering into licenses operated by Bluestack Energy and Petrel Resources.

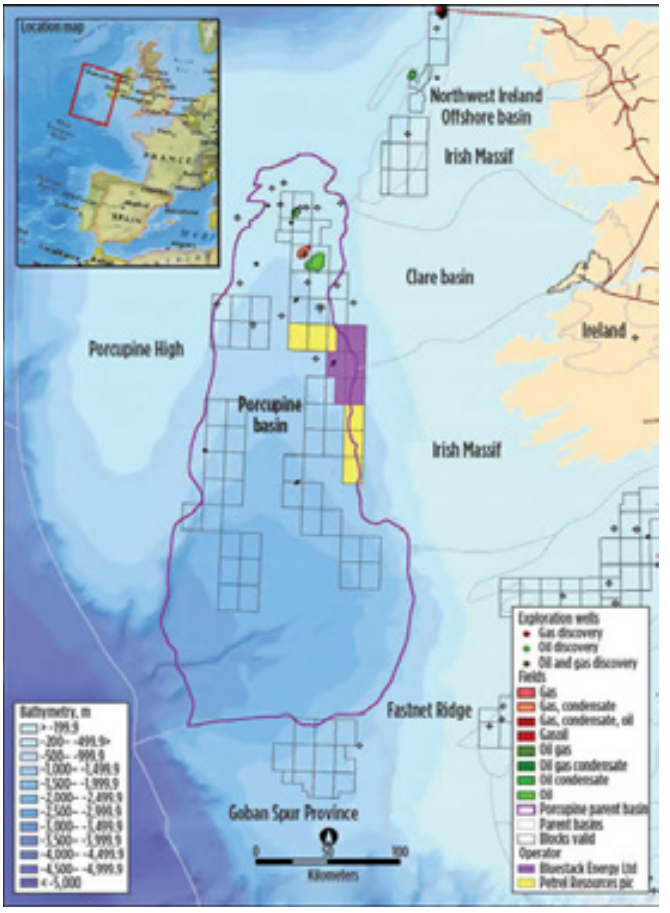
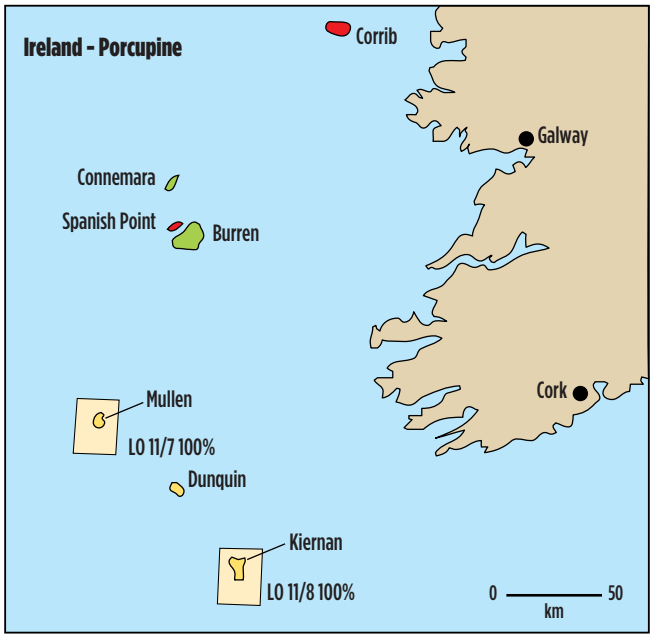


Fig. 2. In addition to the Spanish Point and Burren discoveries, Cairn Energy operates the Mullen and Kiernan prospects.



North of the Dunquin acreage, Antrim's Licensing Option (LO) 11/05, the Skellig Block, which contains the Dunree prospect, has been mapped as a Cretaceous fan complex.

WOODSIDE SEEKS NEW PASTURES

Meanwhile, farm-in activity on the Porcupine acreage acquired in the 2011 round is picking up. The most significant arrival, to date, is Woodside Petroleum, which is farming into three licensing options in the eastern portion of the basin, **Fig. 1.**

The Australian company has agreed to acquire an 85% interest in six blocks, in Licensing Options 11/6 and 11/4, from Petrel Resources, as well as a 90% interest in a further six blocks in Licensing Option 11/3 from Bluestack Energy. The terms were not disclosed. Assuming the deals are approved by the Irish government, Woodside will operate three options. For details on these blocks, please see the Petrel and Bluestack write-ups in the "Other Operators" section of this article.

At this early stage, Woodside has yet to hint at what its drilling program might look like. Chief Executive Peter Coleman gave little away in his comments when announcing the deals, saying only that the Porcupine basin was an emerging province, witnessing increasing activity over recent years. He also said, "Woodside has an outstanding track record working in deepwater environments, and these opportunities fit with our core capabilities and corporate strategy."

However, the firm is unlikely to sit on its hands for long. Licenses must be surrendered, if they remain inactive or an exploration program is not carried out. Those terms resulted in all unworked licenses, awarded in the 1995 and 1997 licensing rounds, being given back to the state. More importantly, Woodside will also be keen to make an Irish discovery and extend its reserves portfolio, following some high-profile delays and setbacks in Australia, and a downward revision to its 2013 production outlook.

In mid-2012, the company put on hold its plans to expand its $14-billion Pluto LNG project, after a five-year search for gas failed to find enough to support further trains. Then, in April 2013, Woodside announced that it was putting on hold plans to develop its Browse gas reserves off Western Australia, using an onshore LNG plant as originally envisaged, amid doubts that the $45-billion project would be economically viable. A scaled-down, floating LNG option is now being investigated.

In early July, Woodside reduced its 2013 production target to 85 MMboe to 89 MMboe, down from a previous estimate of 88 MMboe to 94 MMboe, citing a reduction in output from Pluto, due to an unplanned LNG train shutdown and the longer-than-expected refurbishment of its *Vincent* FPSO vessel.

Uncertainties back in Australia have left Woodside eager to broaden its horizons and invest in a wider pool of projects worldwide. Entry into the Porcupine basin is the latest move in this more globalized strategy.

OTHER OPERATORS/PARTNERS

After some moderate activity in 2009 and 2010, including one success, there was no exploratory drilling offshore Ireland in 2011 and 2012, including the Porcupine basin. What follows are details of activities and plans for individual operators and their partners.

Cairn Energy, et al. The now Cairn-operated (38% interest, effective May 2013) Burren and Spanish Point discoveries lie in adjacent blocks in LO 11/2 of the Porcupine basin, **Fig. 2.** Burren was discovered over 30 years ago by well 35/8-1, after oil flowed during evaluation tests from the Lower Cretaceous. Spanish Point was discovered in 1981 after the 35/8-2 well tested oil and gas from the Jurassic. The well flowed 1,000 bopd and 5 MMcfgd from sandstones of Upper Jurassic age.

In return for the interest that it acquired last May, Cairn will pay a pro-rated share of back costs amounting to $4.1 million and a 63.33% share of future exploration and appraisal costs for up to two wells, subject to a cap. Costs in excess of the cap will be shared by the parties, according to their equity interests.

The estimated, recoverable, contingent resources at Spanish Point are 100 MMboe (2C) and 202 MMboe (3C). Providence stated that with the 3D seismic coverage over eight surrounding blocks, a significant number of adjacent prospects have been identified, with an upside of an additional 500 MMbbl.

Antrim Energy/Kosmos Energy. Antrim was awarded Frontier License Option 11/05 by Ireland's Department of Communications, Energy and Natural Resources, under the Irish 2011 Atlantic Margin Licensing Round on Oct. 17, 2011. The license option area covers Blocks 44/4, 44/5 (part), 44/9, 44/10, 44/14, and 44/15, an area of about 1,409 sq km in the Porcupine basin, situated approximately 110 km offshore southwestern Ireland.

In April 2013, Antrim reached a farm-out agreement with Kosmos Energy. Kosmos will assume operatorship and shoot approximately 1,000 sq km of 3D seismic, to earn a 75% interest in the license. In addition, Kosmos will reimburse to Antrim, a portion of the exploration costs incurred on the blocks, to date.

Europa Oil and Gas/Kosmos Energy. In the Porcupine basin to the west of the Antrim/Kosmos holdings, Europa Oil and Gas reached a farm-in agreement with Kosmos Energy in April

2013. As part of the agreement, Kosmos will acquire an 85% interest in, and operatorship of, both LO 11/7 (Mullen prospect) and LO 11/8 (Kiernan prospect), Fig. 2.

In return for the interest, Kosmos will fully fund the cost of a 3D seismic program on each license, in addition to paying 85% of costs incurred by Europa, to date. Contingent upon an election by Kosmos and Europa to enter into an exploration drilling phase on one or both of the licenses, Kosmos will fund 100% of the costs of the first exploration well on each license, subject to an investment cap. The per-well investment cap for the first well is $90 million on LO 11/7 and $110 million on LO 11/8.

The Mullen prospect is a Lower Cretaceous Aptian play deposited as deepwater turbidite channels, sourced from Barremian marine shales. It is close to the boundary of the south Porcupine basin. The Mullen prospective P50 resources are estimated at 318 MMbbl and are supported by amplitude shut-off at a constant depth.

The Kiernan prospect is a stack of three stratigraphic traps at various levels within the Cretaceous section, Barremian, Valanginian A and Valanginian B. Reservoirs at the Barremian and Valanginian A levels are interpreted to be deepwater turbidite sandstones. The hydrocarbon type in the Middle Cretaceous reservoir is predicted to be most likely oil, with gas predicted in the Valanginian A and B reservoirs. Europa estimates gross, mean, unrisked indicative resources in all three stratigraphic levels at Kiernan to be 1.612 Bbbl in the oil case, and 10 Tcf in the gas case.

Cairn announced in July 2013 that it has contracted the *Blackford Dolphin* semisubmersible (Fig. 3) to drill a planned Spanish Point appraisal. The *Blackford Dolphin* underwent a $400-million updgrade in 2006. Subject to regulatory approvals, the well should spud in second-quarter 2014.

Fig. 3. The *Blackford Dolphin* semisubmersible will drill the third of six wells originally envisioned by Providence Resources, before Cairn assumed operatorship.



Bluestack Energy. The company is actively seeking farm-in partners to progress the Ventry prospect, LO 11/3, into a Frontier Exploration License. Bluestack Energy was awarded the license for a two-year period, commencing Nov. 1, 2011. The Ventry prospect is a large, stratigraphically trapped, deepwater fan complex of uppermost Jurassic age. The seismic character

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shows this to be developed as an extensive, sand-prone stacked channel and basin floor fan complex, analogous to the Miller, Magnus and Burns reservoir sandstones of the North Sea. Ventry has P50 gas-in-place potential of 8 Tcf.

Petrel Resources plc. The firm recently opened a data room for two of its LO 11/4 and LO 11/6 licenses, where prospects have been identified. In LO 11/4, these are interpreted as stacked targets, an Eocene shelf clinoform sheet sands target, and a Lower Cretaceous fan sandstones target with a 1.0-Bbbl potential. Further south, the multiple prospects in LO 11/6 are also thought to be vertically stacked targets, mapped against a major fault boundary.

INVESTOR UNCERTAINTY

Any sizeable find off Ireland in coming months is certain to raise industry concerns over possible tightening of the country's generous fiscal terms (see p. 86, North West Europe regional report, for details of current terms).

The claim by IOOA's Cahill, in a June speech, that the present terms accurately reflect the current stage of exploration in Ireland, is largely supported by a recent report from consultancy PWC, commissioned by Providence Resources. In "*Making the most of our natural resources*," PWC finds that, while Ireland's fiscal regime is significantly more attractive than that of established players, it is on a par with frontier exploration countries in Europe, such as France and Portugal. "There is a broad correlation between state of establishment of the industry, levels of production and the maximum headline rate of taxation," said PWC.

However, there are worries over future tax framework changes, given that Ireland's generous tax regime has been subject to criticism, both at home and internationally, over recent months. PWC describes certainty on future fiscal treatment, in the event of a commercial discovery, as a "key consideration." PWC went on to say, "While Ireland has not introduced retrospective taxation, the debate on the issue of the tax treatment of the industry has engendered a degree of industry nervousness."

Planning problems, which PWC says have damaged Ireland's reputation as a credible location for investment, are also highlighted. The fact that Shell has still not brought gas from its Corrib find onstream, two decades after its discovery, due to environmental protests and planning delays, may have played no small part in a lack of enthusiasm for in the 2011 Atlantic Margin licensing round. In that round, acreage went mostly to minnows.

Estimated returns on exploration in Ireland, based on actual costs during 1970-2012, totaled just €1.8 billion. PWC estimates that expenditures on 158 exploratory wells drilled, plus development costs and other expenses, totaled more than €5 billion, including €2.4 billion for Corrib field.

Legislative changes and licensing improvements, such as the introduction of licensing options in 2011, have helped, but more needs to be done. "The general industry perception is that the regulatory and planning process is still overly complex, needs to be streamlined, requires more technical expertise, and lags behind countries, such as the UK and Norway, in terms of transparency and timeliness," said PWC. WO





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Flurry of regulatory requirements add delays and financial, staffing burdens for OCS projects



OCS compliance requirements have escalated since the *Deepwater Horizon* incident, resulting in permitting delays and increased financial burden for bonding. And yet, the potential prize in the deepwater continues, in many instances, to outweigh the risks, regulatory complexities and costs, as evidenced by the steady recovery in the deepwater rig count.

DAVID BLACKMON, Contributing Editor

BSEE's notice NTL 2010-N10 required deepwater operators to deploy subsea containment resources, resulting in the development of several capping stacks, including this Marine Well Containment System.

Few elements of oil and natural gas development in the United States have experienced a seemingly endless teeter-tottering series of ups and downs as have plans for leasing in the federally-owned waters of the Outer Continental Shelf (OCS). Beginning in 1981, when Congress passed the first of many annual moratoria on new OCS development, subsequent congresses and presidents have struggled to arrive at exactly the right policy approach to accessing and producing the rich energy resources that lie beneath these waters.

OCS POLICY SHIFTS

Here is a brief timeline of some of the major policy shifts that have taken place since 1981:

- **1990.** President George H.W. Bush implements the first executive order, creating a moratorium on OCS development along the nation's Pacific and Atlantic coasts;
- **1993-2000.** Throughout Bill Clinton presidency, the Department of Interior and key congressional committees regularly debated whether or not to spend the funds necessary to update a 1970s-era inventory of potential OCS oil and natural gas reserves. This inventory remains in adequate and dated;
- **July 2008.** President George W. Bush, in response to rising gasoline prices, lifts his father's executive order, denying OCS leasing along the Pacific and Atlantic coasts. A few weeks later, he announces the start of a new OCS five-year planning process that would provide for lease sales in those parts of the OCS;
- **October 2008.** Congress follows President Bush's example, lifting its own ban on OCS leasing;
- **January 2009:** A few days before President Obama assumes office, Bush's Interior Department issues a draft five-year plan. The plan includes proposed lease sales off both the Pacific and Atlantic coasts, as well as the Gulf of Mexico and Alaska. This plan will be very short-lived;
- **February 2009.** Incoming Interior Secretary Ken Salazar announces an indefinite delay in the Bush five-year plan. In September of that year, he states that DOI may not complete a new five-year plan until 2012;
- **January 2010.** DOI announces the cancellation of a scheduled Virginia offshore lease sale that had been planned to take place in November 2011;
- **December 2010.** The Obama Administration effectively reinstates the ban on new offshore leasing along the Pacific and Atlantic coasts, the Eastern Gulf of Mexico, and major portions of offshore Alaska;
- **November 2011.** The Obama Administration announces a new draft 2012-2017 OCS leasing plan, that limits lease sales for oil and gas development to the Western Gulf of Mexico and portions of offshore Alaska, effectively returning allowed leasing back in time to 1981.

So, access to oil and gas leasing and development in the OCS essentially came full circle over a period of 30 years.

NEW REGS AFTER *DEEPWATER HORIZON*

The above timeline above doesn't mention the 6-month moratorium on all deepwater offshore drilling imposed by the Obama Administration in the Gulf of Mexico following the *Deepwater Horizon* blowout and spill that took place in April 2010. Though not formally a part of that moratorium, issuance of shallow-water permits to drill was also subject to a de facto moratorium during that period of time. That moratorium was technically lifted in October 2010, but the pace of issuance of new permits to drill and other regulatory approvals related to OCS development has been slow to recover.

The aftermath of the *Deepwater Horizon* event also served as a catalyst for

Lessons learned from the *Deepwater Horizon* incident may have helped early evacuation of the crew from the *Hercules 265* rig, after a blowout in late July 2013. BSEE is monitoring activities associated with sealing of the well and the possible drilling of a relief well. Photo courtesy of U.S. Coast Guard.



DOI's then-named Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) to issue a series of Notices to Lessees and Operators (NTLs) and permitting requirements that have had the effect of dramatically increasing regulatory oversight of OCS oil and gas development operations. The timeline for these notices:

- **May 30, 2010 – NTL 2010-N04.** Implemented the six-month moratorium, that required OCS operators to cease all drilling of deepwater wells, and prohibited the spudding of any new deepwater wells during this time period;
- **June 6, 2010 – NTL 2010-N05.** Required operators to submit a statement, signed by the CEO of the company, certifying that the operator is in compliance with all relevant operating regulations: "By signing this certification, I certify in my capacity as authorized official that the statements herein are true and complete to the best of my knowledge. I understand that the submission of false statements to the United States is a criminal offense under 18 U.S.C. Section 1001." NTL 2010-N05 also required the conduct of additional inspection, maintenance and testing. This NTL was rejected by a federal court on Oct. 19, 2010;
- **June 18, 2010 – NTL 2010-N06.** Required deepwater operators to demonstrate their preparedness for a well blowout and worst-case discharge (WCD) of oil and/or natural gas, and to include that information in their initial prospect Exploration Plan (EP) and a Development Operations Coordination Document (DOCD). It required operators to recalculate the WCD for existing plans, which BOEMRE would then verify and inform the operator, if it agreed with the calculation. This required the re-submittal of many pre-existing EPs and DOCDs;
- **Aug. 16, 2010 – Revision of NEPA Reviews.** BOEMRE Director Michael Bromwich instructed his staff to stop the use of categorical exclusions under the National Environmental Policy Act (NEPA) in the approval process for deepwater drilling activities indefinitely. The categorical exclusion process was established years before as a means of reducing the volume of unnecessary paperwork and delay associated with NEPA compliance;
- **Oct. 12, 2010 – NTL 2010-N10.** Required deepwater operators to submit information, demonstrating that it has access to and can deploy subsea blowout containment resources significant enough to promptly respond to a deepwater blowout or other well control event;
- **Nov. 15, 2010 – SEMS Regulation:** Required all OCS operators to implement a Safety and Environmental Management System (SEMS) designed to reduce human and organizational errors, deemed to be the root cause of work-related accidents and offshore spills. This rule was beefed up in April 2013 with the SEMS II addition of a provision that requires audits to be conducted by accredited third parties.

Any given regulatory action or new requirements, issued via NTLs, inevitably create a period of time in which delays come about as operators and the regulatory agencies adjust their processes and systems to accommodate the new mandates. In the normal course of business, months will go by between such actions, giving operators and regulators time to absorb the new requirements, and time delays are minimized.

But the *Deepwater Horizon* event was an extraordinary event, one that the federal government felt required an extraordinary response, which manifested itself in this series of new mandates being issued over a six-month period. As one would expect, the period of adjustment and expanded delays in regulatory permitting and approvals resulting from such a rapid issuance of new requirements has been extraordinary, and is still being felt to this day.

EFFECTS OF NEW REGULATIONS

One important factor that has made the Gulf of Mexico such a successful venue for oil and gas development efforts was the predictability of the regulatory and legal environment in the United States. After the government's response to the *Deepwater Horizon* event, that predictability was lost for an extended period of time.

One result of that loss of predictability was that many operators reassigned drilling rigs that had been contracted for work in the Gulf of Mexico, and they have been slow to return. Such rigs are extremely expensive to secure, and operators simply could not afford to have them sit idle during the six-month moratorium and the shaking-out period that followed. As a result, the deepwater rig count had fallen below 30 in 2011, but had risen to 40 earlier this year. Some analysts are predicting that count could more than double by 2017, as companies become increasingly efficient at obtaining the regulatory approvals necessary to do their business.

One challenging impact of the shutdown of drilling in the Gulf of Mexico has been the creation of a manpower shortage, and increased labor costs for operators. Bruce Peterson, Senior Part-

ner at Korn/Ferry International, told the *Houston Business Journal* earlier this year that, as those rigs moved to international locations "The employees went with that equipment, and they started experiencing higher pay in different areas of the world. To come back to the Gulf of Mexico, they'd be looking at less compensation. To get them back, companies are going to have to match that compensation, and that causes the cost to go up."

Mr. Peterson pointed out that wages for offshore rig workers in Africa can be 25% to 50% higher than for similar workers in the Gulf. "It's the perfect storm for employees because of all the new activity that comes with new rigs in other basins and the Gulf of Mexico coming back," he said.

Another impact of this new regulatory environment is that operators must begin their planning processes much further in advance than was previously necessary. It takes about twice as long now to obtain a permit to drill in the deepwater than it did in 2009, but before an operator can even apply for such a permit, it must obtain regulatory approval for an initial Exploration Plan (EP) for the prospect, as well as a Development Operations Coordination Document (DOCD).

Per the BOEM website, an EP "describes all exploration activities planned by an operator for a specific lease(s), the timing of these activities, information concerning drilling vessels, the location of each well, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation."

The DOCD "is a plan that describes development and production activities proposed by an operator for a lease or group of leases. The description includes the timing of these activities, information concerning drilling vessels, the location of each proposed well or production platform or other structure, and an analysis of both offshore and onshore impacts that may occur as a result of the plan's implementation."

Prior to the *Deepwater Horizon* event, in the second half of 2009 through March 2010, the average approval time for a new EP was 52 days, and 77 days for a new DOCD. For EPs and DOCDs submitted in the second half of 2010, those timelines for approval were dramatically lengthened, to 234 days and 216 days, respectively. Such long time delays not only increase costs to operators in a province in which costs are already extremely high, they also increase the likelihood that operators will need to file Revised and Supplemental plans as facts and situational changes take place over time.

To the government's credit, approval times for EPs have gone down significantly since 2010, to an average of 144 days in 2011 and 121 days in 2012. Those time periods are still more than twice the average experienced by operators prior to the *Deepwater Horizon* event, but some operators are optimistic that they will continue to lessen as operators and regulators alike become more efficient at functioning in the new regulatory environment.

However, time frames for approval of DOCDs have gone in the opposite direction since 2010, rising to an average of 230 days in 2011 and 235 in 2012. One factor that seems to be a part of the problem here was the decision to divide the BOEMRE into two separate entities on Oct. 1 2011: the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE).

The two new bureaus were created to serve separate functions, per the official BOEM website:

- BOEM is responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way. Functions include: Leasing, Plan Administration, Environmental Studies, National Environmental Policy Act (NEPA) Analysis, Resource Evaluation, Economic Analysis and the Renewable Energy Program.
- BSEE was created to enforce safety and environmental regulations. Functions include: All field operations, including Permitting and Research, Inspections, Offshore Regulatory Programs, Oil Spill Response, and newly formed Training and Environmental Compliance functions.

However, both agencies must separately approve EPs and DOCDs, and the splitting of BOEMRE into two organizations without increased funding from congress inevitably created staffing shortages at both of the bureaus in some key areas. Those staffing issues, combined with the difficulty in adjusting to new permitting, planning and regulatory requirements, have, without question, contributed to these lengthened approval periods.

As with any other aspect of the oil and gas industry, time is money, and these kinds of regulatory and permitting delays have significantly raised the costs of developing the nation's deepwater resources. Presumably, staffing issues at the companies and regulatory bureaus will be worked out over time, but it is doubtful that approval timelines will ever return to their pre-2010 time frames.

BIG CONCERN: BONDING

One major concern, currently on

The lure of giant discoveries is steadily raising the deepwater Gulf of Mexico rig count, despite increasing requirements for regulatory compliance. Photo courtesy of Pacific Drilling.



OCS operators' minds, is the government plan to revise bonding requirements for OCS projects. Under existing regulations, lessees are required to prove that they possess the financial wherewithal to decommission a given location that is no longer subject to the terms of a federal lease, either due to lease termination or cessation of production. Upon approval of an EP, the lessee must then provide additional financial surety to cover estimates of added liability that would be created through the plan.

Again, both BOEM and BSEE are involved in the governance and enforcement of these requirements, with BSEE maintaining a database of cost estimates that the BOEM then refers to when determining the amount of financial assurance that may be required from each operator.

Lessees currently have several means of providing this financial assurance. They can:

- Post a surety bond that covers the amount of calculated liability;
- Apply for exemption from bonding by supplying BOEM with audited financial statements that demonstrate the financial ability to cover calculated liabilities. (Currently, if one partner is exempt from bonding, BOEM does not require other partners to post bonds);
- Provide treasury bills to the BOEM covering the calculated liabilities; or
- Obtain a third party indemnity guarantee—normally from a parent company or major investor.

These bonding requirements are now subject to an ongoing review. One change, under consideration, would eliminate the current provision, that allows one exempt partner to exempt other partners in the leases. And the government is also currently in the process of revising the cost estimate matrix in ways that could dramatically increase estimates of liability, especially for deepwater development projects. Companies with existing bonds are already beginning to receive notices requiring them to increase sureties over and above what they already have in place.

It remains to be seen how broad the impacts of the new requirements will be, but increasing costs always carry with them the potential of rendering some projects uneconomic to drill.

CONCLUSION

The OCS has always been a challenging, expensive and complex province in which to explore for oil and natural gas, never more so than it has currently become, especially for deepwater projects. Gone are the days when the Clinton Administration and Congress enacted the Deepwater Royalty Relief program, which helped provide the impetus and capital for companies to move into the deepwater in the mid-1990s. And yet, the potential prize in the deepwater continues in many instances to outweigh the risks, regulatory complexities and costs, as evidenced by the steady recovery in the deepwater rig count in the last couple of years.

The oil and natural gas industry has consistently proven over the last 160 years the ability to adapt its business practices, processes and technologies to accommodate a constantly changing regulatory environment. The evidence thus far is that it is continuing to do so in this brave new world of dramatically increased OCS regulatory scrutiny. WO



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Deep, HPHT well in GOM plugged and abandoned using coiled tubing



Coiled tubing (CT) was used, for the first time, to clean out a Gulf of Mexico (GOM) well to 22,610 ft and successfully place a bottom cement plug. The job was completed in 27 days at a lower cost than if a conventional rig was used. Challenges included bottomhole static temperature (BHST) greater than 400°F and the presence of H_2S with a concentration of 75 ppm and 4% CO_2.

ALEXANDER RUDNIK, BURT BONIN and BRENDON WEBB, Coil Tubing Services, a Schlumberger Company; LUKE LEFORT, Schlumberger

After several unsuccessful attempts with wireline to dump-bail cement, the operator successfully used CT to plug the bottom zone of a deep, high-pressure well with cement.

As a result of production having drained once-prolific reservoirs, Gulf of Mexico (GOM) operators are dealing with an increase in well abandonments. This activity is also spurred by environmental concerns and governmental regulatory agencies. Many such well plugging and abandonment (P&A) activities are now performed using CT, which eliminates the need for a drilling rig.

Cement placement is an essential part of every P&A operation. Deep wells (exceeding 20,000-ft, MD) with BHST greater than 400°F and an aggressive H_2S/CO_2 environment, add challenges to the cement slurry design. Furthermore, operations need to be executed safely and within the limits of CT equipment.

An operator needed to P&A a well in the GOM Mobile Bay block. No previous high-pressure, high-temperature (HPHT) cementing operations through CT at BHSTs greater than 400°F had been performed in the GOM. One of the key challenges for this CT intervention was designing a cement system for 425°F, BHST, to be pumped through a 23,620-ft, 1½-in. OD CT string. Concentrations of 75 ppm H_2S and 4% CO_2 increased the complexity of the operation. After several unsuccessful attempts with wireline to dump-bail cement, the operator successfully used CT to plug the bottom zone of this deep, high-pressure well with cement.

BACKGROUND

A single completion well, drilled in 1999, was shut-in after producing sand. As a result, the operator decided to abandon the well. The well contained H_2S, with a concentration of 75 ppm and 4% CO_2. Multiple attempts to inject into the well were unsuccessful. The operator then attempted to dump bail cement with a 30-ft dump bailer tool (2-in. OD), but the cement set prematurely in the bailer, due to the high bottomhole tem-

perature, and the dump bailer was left in the well. The top of this 57-ft fish was at a depth of 22,607 ft. The operator was unsure of the fluid inside the wellbore, and 12 lbm/gal oil-based drilling mud was in the casing. The CT job objectives were:

- Clean out the well to the top of the fish at 22,607 ft
- Pump 8 bbl of cement with a full-bore nozzle to lay a 514-ft cement plug in the 5-in. casing from 22,093 ft to 22,607 ft
- Perforate the 3½-in. tubing at 19,500 ft with tubing conveyed perforating (TCP) guns
- Pump a 300-ft intermediate cement plug in 3½-in. tubing from 19,200 ft to 19,500 ft with a full-bore nozzle
- Perforate the 3½-in. tubing at 14,700 ft with the TCP guns
- Pump a 300-ft top cement plug in 3½-in. tubing from 14,400 ft to 14,700 ft with a full-bore nozzle

KEY CHALLENGES

Several key challenges were encountered during this operation. The well had a maximum potential wellhead pressure (MPWHP) of 13,260 psi, which, in combination with well depth and the H_2S/CO_2 presence, demanded a high level of job engineering, testing, preparation and contingency planning. Ensuring that the pipe and material limitations were respected at all times during the well intervention was essential to the overall job success.

High BHST. One of the key challenges specific to the cementing portion of this CT intervention was the high BHST. A cement system had to be designed for 425°F, BHST, and be pumped through a 23,620-ft CT, 1½-in. OD string. The main properties of the cement slurry that were to be closely monitored included stability, rheology, fluid loss and thickening time. Friction pressure and slurry stability are major concerns when pumping cement slurries through CT.

The cement slurry was a Bingham Plastic fluid, whose viscosity is a function of its plastic viscosity and yield point. These properties describe the amount of solids and their distribution in the system. Therefore, it is essential to add only the required amount of dispersants to avoid over-dispersing the slurry, which might result in loss of stability, settling of solids and free water, and subsequently, plugging of the CT. For the cement slurry thickening time, conventional API test schedules use bottomhole circulating temperature. However, for slurry to be pumped through CT, a rapid temperature increase was expected, mainly due to the small flow areas and rates.

Tests were carried out using the BHST and the recommended modified API schedule to reflect actual conditions encountered during cement placement. The BHST was also higher than the temperature rating of the conventional O-ring material in the BHA. The Viton O-ring seals used in the CT connector are rated at 350°F in seawater. When seals are exposed to temperatures above the temperature rating, there is a limited period of exposure time before the seals fail. Fluoroelastomers, such as Viton, have an exposure limit of 50 hr at 425°F. The risk of O-ring failure was controlled by not operating the BHA in the well for a time period that exceeds the 50-hr exposure limit for the Viton seals.



H_2S and CO_2. Another operating challenge was the potential for the presence of 75 ppm H_2S, and 4% CO_2, in the well. Precautions were taken to minimize the exposure risk to personnel on location, and prevent corrosion and sulfur stress cracking damage to the CT string. Chemical injection pumps were tied into the stack and used to coat the CT with a high-temperature H_2S and CO_2 corrosion inhibitor, as it was run in the hole to protect the CT pipe. Slugs of this inhibitor were also pumped down the CT periodically to recoat the pipe.

In addition, H_2S monitors were worn by personnel on the deck at all times, and self-contained breathing apparatus were placed in various locations on the deck of the lift boat and platform. Weekly H_2S safety drills were held to maintain personnel awareness of response plans. Furthermore, the well was kept in an overbalanced condition to prevent the influx of wellbore fluid. A scrubber and flare system were available for use in the event that returns contained H_2S; however, no H_2S was detected at surface during the operation.

Casing fluid disposal. A third challenge was the limited platform deck space available for disposing the 12 lbm/gal oil-based drilling mud that needed to be circulated out of the casing during the operation. A fluid swap was planned before pumping the balanced cement plugs. However, after the first set of perforations was made at 19,500 ft, circulation was established, with 32 bbl of seawater being pumped down the tubing, and returns coming up the casing. Casing return was seawater, so the operator decided to abort the fluid swap operation. Cement was mixed and pumped, with plans to recirculate the casing return fluid. Shortly after beginning the displacement, drilling mud from the casing was observed at surface. Once it was mixed with the seawater, an emulsion quickly developed and clogged the suction lines going to the fluid pump, causing the pump to cavitate. The digital counter was rendered inaccurate, so the barrels were visually counted, and seawater was used to complete the displacement. A total of 100 bbl of casing fluid was emptied into marine portable tanks for disposal.

CEMENT DESIGN

The key challenge in the cement design was achieving slurry stability. All of

Table 1. Key cement slurry properties.

Slurry density	16.2 lbm/gal
Slurry yield	1.47 ft^3/sack
Plastic viscosity	151.493 cP
Free water	0.0 mL/250 mL in 2 hr
Thickening time	12:39 hr:min @ 30 Bc 12:40 hr:min @ 70 Bc 12:42 hr:min @ 100 Bc
Fluid loss	41 mL/30 min

Table 2. Pumping schedule for cement plug from 22,607 to 22,093 ft.

Pumping	Fluid	Final CT depth, ft	Pumping rate, bpm	Stage volume, bbl	Cumulative volume, bbl
Spacer	Gelled water	22,607	0.25	5	5
Cement	16.4 ppg cement	22,607	0.25	8	13
Spacer	Gelled water	22,093	0.25	5	18
Displacement	Seawater	22,093	0.25	31.8	49.8

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the additives in the cement system were used outside of their documented application range. Laboratory testing was performed, according to the recommended, modified API schedule. The slurry was conditioned at BHT for 30 min and then cooled to 190°F (the maximum temperature rating for the laboratory equipment) for rheology measurements. It took 3 hr for the slurry temperature to drop from 425°F to 190°F. High concentrations of retarder were necessary to ensure an adequate thickening time. Determining the optimal additive amounts, to achieve the required fluid loss, proved to be more challenging. In addition to the fluid-loss additive, the antisettling agent and high-temperature gas migration control additive affected the fluid loss. Several laboratory tests were performed to optimize the cement system that would be batch-mixed using Class H cement:

- 5%, by weight of cement, silica
- 0.05 gal/sack, antisettling agent
- 0.05 gal/sack, antifoaming agent
- 0.06 gal/sack, high-temperature gas migration control stabilizer
- 0.50 gal/sack, high-temperature gas migration control additive
- 0.20 gal/sack, fluid loss additive
- 0.20 gal/sack, high-temperature retarder
- 1.40 gal/sack, retarder for set control

Table 1 summarizes the cement slurry properties. The thickening time of the cement slurry at 70 Bearden Units of Consistency (limit when the slurry is considered as not being capable of being pumped through the CT) was determined to be 12 hr and 40 min.

The pumping schedule for the first cement plug to be pumped down the CT is shown in Table 2. The gelled spacer fluid was prepared by mixing 10 bbl of fresh water with 2 gal of antifoaming agent for circulation in the batch mixer, during which time, 20 lb of an antisettling agent were added to the batch mixer. After allowing 45 min for the antisettling agent to hydrate, the spacer fluid was ready to be pumped downhole and transferred to the displacement tanks.

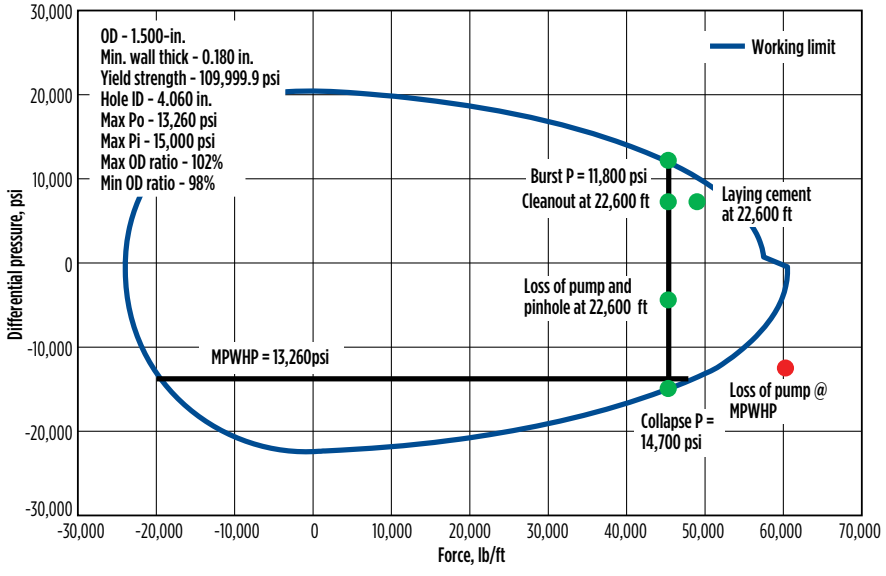
Table 3. CT string specifications.

Outer diameter, in.	Nominal thickness, in.	Segment length, ft	Segment volume, bbl
1.500	0.134	4,025.0	5.9
1.5	0.145	1,715.0	2.4
1.5	0.156	8,295.0	11.4
1.5	0.175	5,250.0	6.7
1.5	0.190	4,335.0	5.3

Table 4. MWCP values for all CT string sections.

		MWCP, psi				
End CT depth, Ft	WT, in.	Run 1, 8.6 ppg	Run 2, 8.6 ppg	Run 3, 8.6 ppg	Run 4, 8.6 ppg	Run 5, 8.6 ppg
0	0.134	13,500	12,500	12,000	11,000	10,000
4,025	0.134	12,800	12,300	11,800	10,850	9,900
5,740	0.145	13,500	12,500	12,000	11,000	10,000
14,035	0.156	12,100	11,350	10,600	9,800	9,000
19,285	0.175	10,000	8,650	7,300	6,550	5,800
22,100	0.19	4,500	2,250	0	0	0

Fig. 1. CoilLIMIT design plot with CT located at 22,600 ft.



CT STRING DESIGN/ VERIFICATION

The CT string design was a key element in allowing the service company to intervene in a well with 13,260-psi MPWHP. The string details for the 1½-in. OD, HS-110 CT string used for this operation are shown in Table 3.

The maximum allowable collapse pressure for each CT wall thickness change depends upon the forces applied to the CT while it is in the well. The maximum well control pressure (MWCP) is the maximum pressure for well control, only. MWCP should not exceed any of the following thresholds:

- Category pressure limit +1,500 psi
- 1.5 times the MPWHP, or the working pressure of the component with the lowest pressure rating
- The CoilLIMIT coiled tubing pressure/tension limit model curve value
- The working pressure of the component with the lowest pressure rating in the well control stack, including the wellhead or connections and reel components.

Therefore, the MWCP is determined by the CoilLIMIT 80% collapse limit for each wall thickness as per Table 4. The MWCP values are based on the assumption that the well is dry (filled with 1.64 lbm/gal, gas). The actual MWCP during the operation was dictated by the CoilLIMIT working envelope. The CoilLIMIT design plot with the CT positioned at 22,600 ft is shown in Fig. 1.

In the event that a well kick is detected with the well full of 8.6 lbm/gal seawater, the CT would be halted, and the well would be choked in an attempt to stabilize the returns and achieve bbl-in/bbl-out. With the well full of 8.6 lbm/gal seawater, the maximum wellhead pressure to balance the well was 5,200 psi. The pump rate would be increased, and the wellhead pressure (WHP) maintained at 5,200 psi to keep the well overbalanced until the kick is circulated out. An annular volume of seawater would be pumped, and if the pressure stabilized, a review would be performed to determine if the operation should be continued. If the pressure did not stabilize, the

CT would be pulled out of hole to the surface. However, if well control was lost, the contingency plan called for pulling the CT out of hole to 6,000 ft, the minimum safe depth at which the CT would be able to withstand the MWCP in the worst case scenario (CT string failure and loss of fluid pump). If the WHP increased over the MWCP defined for each CT section, the CT would be cut at surface with the blowout preventer shear rams, and the well would be shut in.

DEFORMATION ANALYSIS

Each time the CT is run in and out of a well with high-circulating pressure, there is a possibility that the tubing diameter will increase to prevent the tubing from passing through the stripper, rendering the tubing unusable for future use. This effect, called pipe ballooning, can be prevented if the proper CT material and tubing size are selected for the anticipated loading conditions, such as circulating pressure and the number of tubing passes over the reel and gooseneck required to complete the job. In addition, high-pressure cycles of the CT string over the reel core and gooseneck will inevitably lead to wall thinning, which decreases the effective working envelope for that section of the CT string. The CoilDEFORMATION coiled tubing elongation and ballooning deformation model was used to verify that the correct CT material and size (OD and wall thickness) were chosen for this operation.

As shown in Table 5, it is reasonable to conclude that a 5% wall-thickness reduction (based on minimum CT wall thickness) must be used in the design for this particular well intervention. The results also show that the CT string exhibits satisfactory, permanent deformation changes that will not create significant problems, including compatibility of the CT string and pressure control equipment. Ballooning of the CT OD to 1.513 in. is within an acceptable tolerance for the CT pressure bushings, both standard (0.03 in.) and oversized (0.08 in.) bushings clearance.

RISK MANAGEMENT

Several preventative and mitigative measures were taken to manage the risks associated with this operation and ensure that it was completed safely. All required laboratory testing of the cement slurry was performed. A thorough job procedure was completed for this operation that included detailed cement mixing procedures. A quality assurance/quality control kit for cementing operations was

Table 5. Coil deformation analysis results, based on CT string history and predicted operating load number of cycles.

Minimum WT, in.	Section length, ft	Deployed length, ft	Permanent elongation		Minimum wall thickness		Ballooning	
			ft	%	in.	%	Avg OD, in.	%
0.134	4,025	4,025	2.24	0.06	0.132	-1.49	1.503	0.21
0.145	1,715	1,715	0.81	0.05	0.143	-1.45	1.503	0.19
0.156	8,295	8,295	9.5	0.11	0.151	-3.4	1.509	0.59
0.175	5,250	5,250	25.21	0.48	0.172	-1.87	1.505	0.35
0.190	4,335	2,815	15.67	0.56	0.186	-2.01	1.504	0.28


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used on location to test the cement after it was mixed and before it was pumped downhole. A digital scale was also used to ensure accurate chemical weights, when mixing the cement slurry. High-temperature corrosion inhibitor was pumped, and applied to both the inside and outside of the CT pipe during the operation.

The mixing area was designated as a hazardous area, and non-essential personnel were kept clear of this area to minimize exposure to the personnel. A backup fluid pump was rigged up on location in the event that the primary pump failed at any time during the operation. All crew members wore proper personal protective equipment, including H_2S monitors. The H_2S detectors were set up on the re-

DECOMMISSIONING IN THE NORTH SEA

ZIRCOSOL solvent cleans a Pb-210-contaminated heat exchanger

A North Sea operator faced the challenge of decommissioning a stainless steel heat exchanger on a gas production platform 70 mi northwest of Den Helder, The Netherlands. The heat exchanger, consisting of multiple, small-diameter stainless steel tubing connected to an 8-in. diameter manifold, was contaminated with radioactive Pb-210 scale.

Naturally occurring radioactive material (NORM) can result from co-precipitation or electrochemical deposition of radioactive elements, including radium, polonium and lead. NORM deposits usually take the form of mineral scale such as barium/radium sulphate or elemental metallic lead.

With management of NORM and other contaminants continuing to be an ever-increasing challenge for operators, conventional solutions, such as high-pressure water jetting typically fail to address all decontamination issues.

M-I SWACO has developed its ZIRCOSOL solvent as part of the EXKAL service line that includes comprehensive chemical technology solutions, in addition to specialist expertise to help operators deal effectively with scale and other deposits that can obstruct production or abandonment operations. The ZIRCOSOL solvent is a unique chemistry designed to efficiently and safely remove radioactive metal deposits from NORM-contaminated equipment through a simple static soak process.

Because of the heat exchanger tubing construction, removal of Pb-210 was not mechanically possible. HSE considerations and economics ruled out decontamination onshore. The operator invited M-I SWACO to propose a solution.

In compliance with legislation governing working standards for heights, the M-I SWACO team set up the proprietary bund tank system, complete with handrails and access/egress steps as close to the heat exchanger as possible. The closed loop system was leak tested and then filled with the ZIRCOSOL solvent, which was pumped through the entire heat exchanger bank to contact all internal surfaces of the exchanger. The dissolver was allowed to soak for a specified amount of time. Approximately 200 l of dissolver was pumped through the closed loop system every couple of hours to remove any potential air caps that may have been generated, as the scale was being dissolved.

Both of the heat exchanger banks were decontaminated and rendered free of Pb-210. This enabled the safe removal of the heat exchanger banks, which were then shipped onshore for safe disposal in compliance with local environmental regulations. As such, the ZIRCOSOL solvent enabled the efficient, safe removal of radioactive metal deposits in the heat exchanger that could not be cleaned by mechanical means.

Pb-210 containing scale (left) in a heat exchanger was dissolved through a proprietary ZIRCOSOL solvent injected through a closed loop treatment design (right).





turn tank, and a scrubber and flare system was also used. In addition, rescue equipment was set up on the platform and the lift boat, in the event of an emergency.

JOB EXECUTION

Table 6 summarizes the CT runs made into the well.

First run: Fill cleanout and pumping a cement plug. The well's initial shut-in tubing pressure (SITP) was 2,750 psi. While the CT was being run in the hole, the surface-controlled subsurface safety valve (SCSSV) was tagged and had bled down to 0 psi. The control line was re-pressurized to 7,500 psi and monitored. Once the gauge held steady, the CT was run in the hole again and did not tag the SCSSV. After opening the SCSSV, the WHP increased to 6,750 psi, where it was maintained (Fig. 2) as the CT continued to be run in the hole, while pumping 0.25 bbl/min seawater. The CT tagged fill at 20,123 ft and cleaned out to 22,610 ft. After circulating a bottoms-up, an injection test was performed, but the WHP increased to 7,500 psi and injection was not established. Eight bbl of cement were pumped in the 5-in. casing from 22,607 ft to 22,093 ft. Then, the CT was pulled out of the well, maintaining a WHP of 6,800 psi after spotting the cement. After waiting 26 hr for the cement to set, a negative test was performed on the cement plug, with pressure on the well increasing back to 6,800 psi after 3 hr.

Second run: Pumping the cement plug. Because a successful pressure test

Table 6. CT run summary

Run #	Objective	Maximum depth, ft
1	Cleanout to 22,607 ft and pump cement plug from 22,093–22,607 ft	22,610
2	Pump cement plug from 19,900–22,037 ft	22,037
3	Perforate tubing with TCP guns at 19,500 ft	19,874
4	Perforate tubing with TCP guns at 19,500 ft	19,500

Fig. 2. CT post-job data acquisition plot for Run #1.

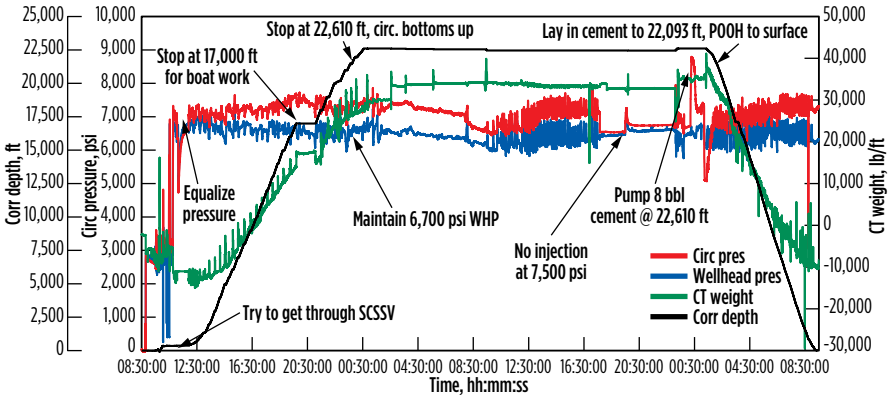




Fig. 3. CT post-job data acquisition plot for Run #2.

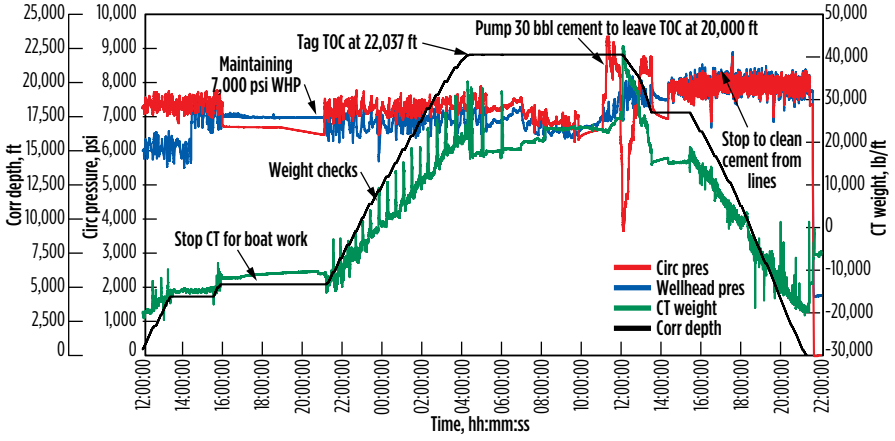
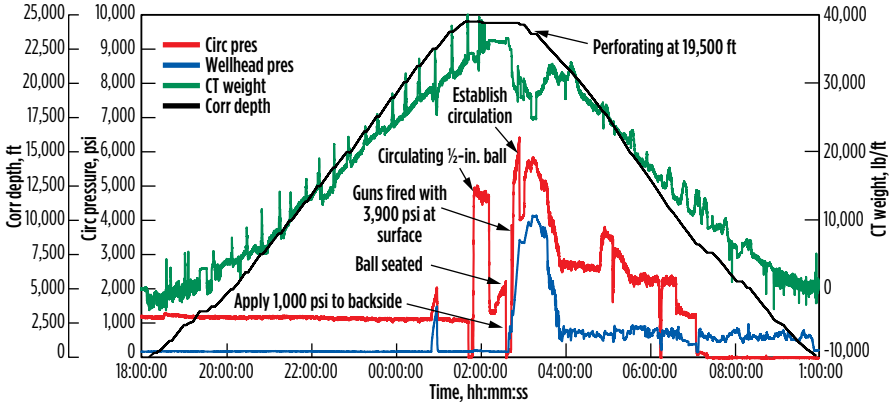


Fig. 4. CT post-job acquisition data plot for Run #4.



was not achieved on the first cement plug, the decision was made to pump another cement plug into the well. The CT was run in hole and tagged the top of cement (TOC) at 22,037 ft, Fig. 3. On this run, 30 bbl of cement were pumped in the 5-in. casing and 3½-in. tubing, from 22,037 ft to 19,900 ft. The CT was then pulled out of the well, maintaining 7,500 psi, WHP, after spotting the cement. After waiting 18 hr for the cement to set, a negative test was successfully performed. The tubing and casing were then pressure tested to 1,000 psi for 30 min.

Third run: Perforating with tubing conveyed perforating (TCP) guns. The CT was run in the hole and tagged the TOC at 19,874 ft, where the CT was picked up to 19,500 ft and a 7/16-in. ball was pumped down the CT. After pumping three reel volumes of seawater, there was no indication that the ball had seated. The CT was then pulled out of the hole to 10,000 ft, and acquisition data were reviewed. It was determined that the TCP guns likely had not fired. Due to the communication between the CT and the CT tubing annulus, there was a possibility that the tools were lost in the hole. As a result, the slim tool and live TCP guns undeployment contingency procedures were followed, to prevent pulling out of the packoff or detonating the guns while retrieving them from the well. When the CT reached surface, the TCP guns were safely retrieved without incident. The BHA was inspected, and the O-rings on the CT connector were found to be melted, which prevented the pressure differential across the firing head that was needed to fire the TCP guns.

Fourth run: Perforating with TCP guns. The BHA was rebuilt, and the CT was then run in hole to 19,500 ft, and a 7/16-in. ball was once again circulated. After the ball seated, 500 psi were applied to the CT-tubing annulus. The CT was then pressured to 3,900 psi, as shown in Fig. 4, and the TCP guns were fired. Circulation was established down the tubing and up the casing, and the choke was manipulated to maintain WHP at 4,000 psi to keep the casing fluid from swabbing into the tubing. With CT at 18,000 ft, the WHP was bled off in 500-psi increments. The casing and tubing pressures were nearly equal, despite an expected 3,450-psi hydrostatic pressure in the casing. The CT was then pulled out of the hole, while 500 psi were held on the choke.

Bullheading intermediate and top-cement plugs. The operator changed the job procedure to pump the intermediate and top cement plugs from the surface (not through the CT) after the fourth CT run. Casing fluid (32 bbl) was circulated back to surface before pumping the intermediate plug, with all returns being composed of seawater. The operator also decided not to perform the fluid swap that was originally planned to minimize mud returns at the surface. Instead, the operator recirculated the casing fluid, when pumping the intermediate plug from surface. When the cement (13 bbl) had been mixed and pumped, drilling mud was seen in the return tanks at surface. As the mud mixed with the seawater returned to the tanks, the fluid became difficult to pump, because the suction line became clogged and the fluid pump began to cavitate. Fresh seawater was pumped to complete the displacement for the operation, and a total of 100 bbl of drilling mud was disposed of at surface, which was 85 bbl more than planned.

RESULTS

The main objective of this operation was achieved without any HSE incidents. The job was successfully completed in 27 days at a much lower cost than if a conventional rig had been used. The CT cleaned out the well to 22,610 ft and was used to successfully place the bottom cement plug. One additional CT run was necessary to pump a second cement plug, as the original bottom cement plug could not be pressure-tested. The CT was also used to perforate the production tubing at 19,500 ft. These CT operations enabled the installation of two additional cement plugs required by regulatory agencies to be bullheaded, and allowed the operator to finally move forward with permanent abandonment of the well.

LESSONS LEARNED

For high-temperature services above 350°F, the BHA should be redressed after every run to minimize the risk of O-ring

failure downhole. The pressure test, of the break in the pressure control stack, should include a pressure test of the CT connector and dual-flapper check valves by pressuring up, down the kill line, instead of down the CT string.

Another lesson learned was that the pumping of oil-based mud, contaminated with seawater, should be avoided to prevent damage to the fluid pumps. In addition, the job planning and coordination between the Schlumberger CT and cementing segments, the CoilTOOLS coiled tubing intervention tools and solutions, the Schlumberger New Orleans Technology Center, the InTouchSupport.com online support and knowledge management system were critical to the success of the operation. Quality control of the cement slurry design, mixing, and pumping was also very important in completing the operation's main objective.

CONCLUSIONS

The team reached the following conclusions after evaluation of the P&A project:

- CT cementing operations, with a 1½-in. CT string, can be executed successfully at depths exceeding 22,000 ft and BHSTs approaching 425°F
- Conventional O-rings can be used in CT BHAs, provided the exposure time is kept to a minimum
- CT is a valuable P&A tool that can help reduce overall abandonment costs by providing a reliable, efficient alternative to wireline dump-bailing and rig cement-bullheading techniques
- HPHT CT cementing operations require rigorous design, testing and planning, as compared to conventional CT interventions. WO

ACKNOWLEDGMENT

This article is adapted from Brendon Webb et al, "Plug and abandonment of a deep high-pressure and high-temperature Gulf of Mexico well using coiled tubing: A case history," paper SPE 163942 presented at the SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, 26-27 March, 2013, The Woodlands, Texas, USA.

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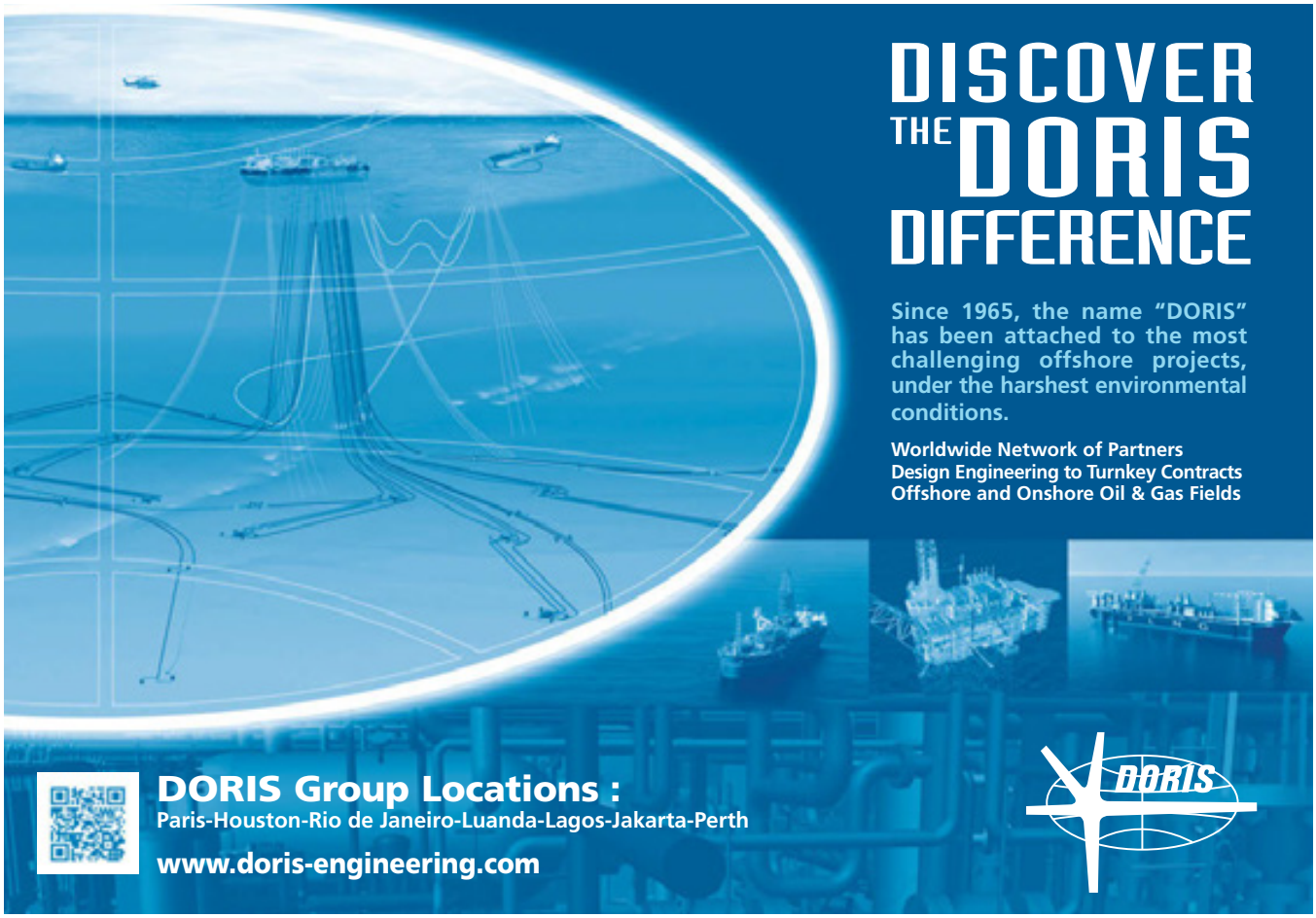
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ALEXANDER RUDNIK is a coiled tubing technical manager with Coil Tubing Services, a Schlumberger company, based in Houston. He has 20 years of experience in coiled tubing, matrix acidizing, and cementing. Mr. Rudnik holds an MS degree in mechanical engineering from Bryansk State Technical University, Russia.

BURT BONIN is a senior sales engineer for Coil Tubing Services, based in Lafayette, La. He has 30 years of experience in drilling and completions, coiled tubing, matrix acidizing and cementing. Mr. Bonin joined Schlumberger in 1992 and has been through a number of field, sales, and managerial positions working exclusively in the Gulf of Mexico.

BRENDON WEBB is a sales engineer with Coil Tubing Services, based in Anchorage, AK. Mr. Webb joined Schlumberger in 2005 and has worked in field and managerial positions in Texas, West Virginia and Louisiana prior to his current assignment in Alaska. He received his BS degree in chemical engineering from the University of Michigan.

LUKE LEFORT is a fluid technical engineer with Schlumberger, based in New Orleans Louisiana. He has eight years of experience, concentrated in well cementing. Mr. Lefort received his BS degree in chemistry from Nicholls State University.



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Offshore Europe 2013: Planning for the next 50 years of North Sea activity

Offshore Europe 2013 quick facts:

- 2013 marks OE's 40th anniversary in Aberdeen
- First-ever OE Energy Festival to feature music, arts
- Most recent event, in 2011, drew more than 31,000 unique attendees
- More than 1,500 exhibitors booked this year

MELANIE CRUTHIRDS, News Editor

Taking on the theme of "The Next 50 Years," presentations and panel discussions at the upcoming SPE Offshore Europe Conference and Exhibition aim to inform attendees about the state of affairs in the historically productive North Sea, and what the future could look like for the area. To be held Sept. 3-6, 2013, at the Aberdeen Exhibition and Conference Centre in Aberdeen, Scotland, the event will celebrate its 40th anniversary in the city this year.

Since the mid-1960s, oil and gas operators have seen varying degrees of success and decline with projects offshore Europe. The region is now poised to take on a new life, with new technologies and best practices being used to extract additional resources from existing, aging fields. At Offshore Europe 2013, at least four of the conference's 11 keynote sessions will be devoted to discussing the specific needs and potential found in North Sea plays, as the region experiences its own shift-change, following decades of E&P activity.

In addition to the keynote sessions, the conference program will feature technical sessions, poster presentations, breakfast briefings, topical lunches, SPE training courses, a full-week educational program, and various UK Trade and Investment Opportunities seminars. Attendees will also have access to the show's exhibition hall (Fig. 1) and "Deep Water Zone," where companies from this growing industry sector will present their latest technologies and experiences. Items new to the conference this year include the OE Energy Festival and the MyOE web portal

KEYNOTE SESSIONS

The first keynote session of the week will be chaired by Oil & Gas UK CEO and SPE Offshore Europe 2013 Execu-

Fig. 1. The last Offshore Europe show, held in 2011, set an all-time conference attendance record of more than 31,000 attendees, and featured OE's largest-ever exhibition area, at more than 25,000 sq m.



tive Chairman Malcolm Webb, with input from:

- Andrew Gould, chairman, BG Group
- Bob Keiller, CEO, Wood Group
- Sam Laidlaw, CEO, Centrica
- A senior UK government minister

This year's keynote sessions, including Webb's opening address, will cover "current issues and critical future trends in the upstream E&P industry."

On Sept. 3, two keynote sessions will cover "Oil and gas in the future energy mix" and "The global opportunity: Exporting oil and gas services, goods and expertise." The first session, with speakers from Shell, the International Energy Agency, the Low Carbon Vehicle Partnership, IHS Energy and the Dutch Ministry of Economic Affairs, will explore the global energy outlook, the future of transport fuels; and unconventional resources in both the U.S. and UK. The second session will discuss the UK and Europe in the global oil and gas export market, and will include presentations from a former Shell executive, a UK Minister of State for Trade and Investment, Petrofac, Van Oord Offshore Contracting and Dredging Group, Kongsberg and Xodus Group.

Attendees will have the opportunity to learn more about "Planning for long-term North Sea drilling," "The independent oil company," "Industry progress since Macondo," and "Taking operations to frontier areas" on Sept. 4. Through these four presentations, speakers will explore surging drilling activity in the North Sea, the role of independent oil companies in today's regional E&P landscape, regulatory and other initiatives seen in the industry since Macondo, and the challenges and opportunities found in emerging frontier regions. Professionals scheduled to speak on these topics come from organizations like Oil & Gas UK, IHS Petrodata, Rig Management Norway, Awilco Drilling, Transocean, Ensco, KCA Deutag Drilling, Energy Ventures, EnQuest, TAQA Bratani, AT Kearney, GDF Suez E&P, ADIL, Genel Energy, Wood Mackenzie, Bridge Energy, DECC, Faroe Petroleum, Dana Petroleum, Schlumberger UK, Oil Spill Response Limited, Helix Energy, The Bromwich Group, the European Commission, Tullow Oil, Iraq British Business Council, Marathon Oil and Arctic Base Supply.

Nearing the end of the conference, attendees can catch presentations covering "Decommissioning and value extraction for end of life," "Journey from procedure to practice," "Financing investment in the oil and gas industry: Challenges and opportunities," and "The technology imperative: Collaborating today to realize the next 50 years of North Sea potential." These Sept. 5 sessions will provide more information on maximizing asset value, putting valuable procedures into practice, creative financing techniques for risky projects and leveraging technology to access and recover remaining North Sea resources. Speakers will come from organizations including: ExxonMobil, CNR International, Allseas Group, Brent Decommissioning Project, Statoil, Nexen, Australian National University, the Royal Air Force, Bibby Offshore, Standard Chartered Bank, Cairn Energy, Tullow Oil, Petrofac, Morgan Stanley, BP, Norway's Ministry of Petroleum and Energy, and AMEC.

On the conference's final day, Sept. 6, a keynote presentation will delve into the career outlook for today's oil and gas professionals under the topic of "Oil and gas: Your future, today." As the first generation of North Sea innovators retires, a skills gap has resulted. Presenters for this session represent Apache North Sea, the Scottish government, OPITO and Maersk Oil North Sea UK.

TECHNICAL SESSIONS

In addition to a full week of keynote sessions, Offshore Europe 2013 will feature a variety of technical sessions, designed to "address key elements in exploration technology and geophysics, well engineering, HSE, reservoir management and facilities." Presenters will bring their insight into, and experience with, topics including:

- Developments in pipeline analysis
- Exploration case studies
- Health & safety
- Enabling field life extension
- Reservoir depletion and production enhancement
- Advances in subsea construction and technology
- Drilling technologies
- Reservoir development planning and techniques
- Managing oil spills
- Ensuring the structural and marine integrity of floating production installations over their lifetime
- Reservoir evaluation
- Cementing and completions
- Environment: Tools and management

Additionally, several e-poster sessions will cover topics such as "Exploration case studies," "New solutions (old problems)," "New solutions (planning & development)," and "Inspection & maintenance (An inspector calls)."

WHAT'S ON IN 2013

The organizers of Offshore Europe 2013 have introduced two new, interactive ways for attendees to learn more about the latest advancements from the region. For pre-show preparations, the MyOE web portal allows users to create an account, from which they can access a calendar to schedule and track meetings, and search exhibitors by name or specialty.

Also new this year is an event that will bring attendees out of cyberspace, and into the heart of Aberdeen. The Offshore Europe 2013 Energy Festival puts the host city, one of Europe's energy hubs, on display with outdoor music in the city center, a country fair and a special industry-related photography exhibit.

Although not new to the 2013 event, the conference's "Deep Water Zone" will give attendees a chance to further explore the latest technologies from this growing industry sector, especially in areas such as Brazil, the Gulf of Mexico, and West and East Africa. The Deep Water Zone, in its own hall adjacent to the main exhibition floor, will also feature daily technical presentations, Fig. 2. WO

Fig. 2. Attendees at Offshore Europe 2011 listen to a presentation at the biennial conference's Deep Water Zone, which will be featured for the second time in 2013.





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DRILLING AND COMPLETIONS CONFERENCE

HPHTConference.com | **September 26–27, 2013 | Houston, TX**

Learn Best Practices and Effective Solutions for the Unique Challenges of High Pressure, High Temperature Drilling and Completions

Gulf Publishing Company invites you to attend the **2013 *World Oil* High-Pressure, High-Temperature Drilling and Completions Conference,** to be held September 26–27 in Houston, Texas, at the Norris Conference Centers-CityCentre. The 2013 event will feature a high-level, two-day technical program devoted to knowledge sharing and best practices in high-pressure and/or high-temperature (HP/HT) drilling.

World Oil HPHT Drilling & Completions Conference is an exclusive forum in which many of the industry's most innovative and accomplished professionals meet to network and discuss the latest developments in: operator responsibility; materials and materials testing; equipment design, development and implementation; subsea technology; MDP applications under HPHT conditions; real-time production monitoring; case histories; and more.

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AGENDA DAY 1
September 26, 2013

7:30–8:30 a.m.	**Registration**	
8:30–8:45 a.m.	**Opening Remarks:** John Royall, President and CEO, Gulf Publishing Company	
8:45–9:15 a.m.	**Keynote Presentation:** James M. Pappas, P.E. Vice President Technical Programs, Research Partnership to Secure Energy for America (invited)	
9:15–9:45 a.m.	**Morning Break**	
	Track 1: EXPLORATION & DRILLING	**Track 2: COMPLETIONS & PRODUCTION**
	Session 1 **SESSION CHAIR:** Chris Kocurek, Engineering Manager, Cameron Subsea Systems	**Session 4** **SESSION CHAIR:** Michael Payne, Senior Advisor, BP E&P Technology
9:45–11:45 a.m.	The Future of Well Control for Deepwater HPHT Drilling – Christian Leuchtenberg, Managed Pressure Operations PTE Ltd. Fatigue and Fracture Analysis for Equipment to be used in HPHT Applications – Evgeny Podnos, ALTISS Technologies LLC Subsurface Safety Valve Design, Development and Qualification Testing Considerations for Ultra-HPHT Applications – Grant Thompson, Baker Hughes Incorporated	Difficulties of, and Solutions for, Designing HPHT Load Bearing Interfaces – Nigel McKie, FMC Technologies Latest Perfluoroelastomer Parts for Demanding Oil and Gas Applications – Mark Whitmarsh, DuPont Tackling HPHT Sensing Challenges – Nick Haywood, Process Management, Emerson
11:45 a.m.–1 p.m.	**Lunch Followed by Coffee and Dessert in Exhibit Hall**	
	Session 2 **SESSION CHAIR:** Brian Skeels, Engineering Technologies Director, FMC Technologies	**Session 5** **SESSION CHAIR:** Earl Shanks, OIE Chief Technologist, Oceaneering International, Inc.
1–2:30 p.m.	**CASE STUDY:** Full Scale MPD and Closed Loop Implementation Approach to Well Construction in a Previously Undrillable Field – Stephen O'Shea, Weatherford **Questions and Answers**	**CASE STUDY:** Integrating DPR with Real Time Monitoring System for Digital Field Application: Key Enablers for Strategic Production Optimization of Wells Producing from Deep HP-HT Sour Carbonates in North Kuwait – Bhavadip Navinchandra Vaidya, Kuwait Oil Company Qualification of T&C Riser Connections with Metal to Metal Seals and Sour Service Compliance for the HPHT Environment – Mike Tricarico, Vallourec USA Corp. Ultra High Pressure Fracturing in KS Area – Xuefang Yuan, Tarim Oilfield Company of CNPC
2:30–2:45 p.m.	**Afternoon Break**	
	Session 3 **SESSION CHAIR:** Grant Affleck, Global BD Manager - DS Technology, Weatherford	**Session 6** **SESSION CHAIR:** Ian Penman, Global Advisor, Halliburton Completion Tools
2:45–4:45 p.m.	**Panel Discussion:** Differential Pressure The MPD; CCS; CDM and Steady State Drilling Evolution – Laurence Ayling, Maris International Using Closed Loop Techniques throughout Wellhead Construction Process – Carl Hills, Weatherford **Closing Remarks:** John Royall, President and CEO, Gulf Publishing Company	Performance of PEEK and Other PAEK Materials in HPHT Conditions – Richard Leibfried, Victrex Addressing the Instrumentation Needs of HPHT Applications – David Faichnie, FMC Technologies

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AGENDA DAY 2
September 27, 2013

7:30–8:30 a.m.	**Registration**	
8:30–8:45 a.m.	**Opening Remarks:** John Royall, President and CEO, Gulf Publishing Company	
8:45–9:15 a.m.	**Keynote Presentation:** To be announced	
9:15–9:45 a.m.	**Morning Break**	
	Track 1: EXPLORATION & DRILLING	**Track 2: COMPLETIONS & PRODUCTION**
	Session 7 **SESSION CHAIR:** Robert Sokoll, Staff Drilling Engineer, ConocoPhillips	**Session 10** **SESSION CHAIR:** Darren Bane, Chairman for API 14A, 14B, and 14L, Baker Hughes Incorporated
9:45–11:45 a.m.	FEA Evaluations of Casing and Tubing Connections for HPHT – Jueren Xie, PhD, Peng, C-FER Technologies Preparation of HPHT Hydraulic Fracturing Fluid – Sumit Sekhar, College, ISM Dhanbad Materials Selection and Mechanical Testing of the Aluminum Alloy Drill Body for HPHT Well – Feng Chun, Tubular Goods Research Center of CNPC	Design Guideline Strategies for HPHT Equipment – Brian Skeels, FMC Technologies Wireline Tools in Conventional Wireline Deployed Operations – John Dahl, Product Line Manager, Baker Hughes Incorporated The Use of Nanotechnolgy in the Development of a Distributed Fibre-optic Temperature Sensor for Subsea Applications – Gary McDowell, School of Engineering & Built Environment, Glasgow Caledonian University
11:45 a.m.–1 p.m.	**Lunch Followed by Coffee and Dessert in Exhibit Hall**	
	Session 8 **SESSION CHAIR:** Kaz Javanmardi, HPHT Principal Technical Expert; PT Deepwater Wells, Shell International Exploration and Production Inc.	**Session 11** **SESSION CHAIR:** Jim Raney, Engineering and Technology Manager, Anadarko Petroleum Corp.
1–2:30 p.m.	**CASE STUDY:** High Solid Content- High density- Engineered Particle Size Distribution Slurry Allows for Successful Cementation of HPHT Well Crossing Fault, in Gulf of Mexico – Degaul Nana, Schlumberger **CASE STUDY:** Geophysical/Geological Applications Used to Address HPHT Drilling Hazards Pre-drill and Post-drill, Jaguar-1 Well, Offshore Guyana – Allan Kean, Repsol **Questions and Answers**	High Temperature Full and Sub-Scale Fatigue Testing in Sour Environments – Steven Kinyon, PhD, Stress Engineering Services HPHT Fracturing and Reservoir Monitoring Tool – Randy A. Normann, Perma Works LLC
2:30–2:45 p.m.	**Afternoon Break**	
	Session 9 **SESSION CHAIR:** Bob Holicek, Deepwater Theme Manager, Schlumberger North America Offshore	**Session 12** **SESSION CHAIR:** Ken Young, Staff Consultant, Stress Engineering Services Inc.
2:45–4:45 p.m.	**Panel Discussion:** Requirements for HPHT Design Criteria Managed Temperature Drilling – Tony Worthen, Drill Cool Systems, Inc. **Closing Remarks:** John Royall, President and CEO, Gulf Publishing Company	Coiled Tubing Intervention in an Ultra High Pressure Well – Bill Zhang, CNPC USA Subsea Well Intervention Operations – HPHT Design and Operation Consideration – Colin Johnson, Helix ESG

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Discover the technology and applications that are enabling companies to drill deeper and complete wells in increasingly difficult conditions.

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Session highlights include:

- **Coiled Tubing Intervention in an Ultra High Pressure Well** – *Bill Zhang, CNPC USA*
  Learn how CNPC used coiled tubing to change a leaky subsurface safety valve and eliminate potential safety hazards in an ultra-deep HPHT condensate gas well.
- **High Temperature Full- and Sub-scale Fatigue Testing in Sour Environments** – *Steven E. Kinyon, Ph.D, Stress Engineering Services*
  Sour service test conditions are often used to evaluate the environmental effects of hydrogen sulfide (H2S) on the fatigue response of materials for design considerations in tubular structures. Previous tests have been conducted at ambient and moderate temperatures (below 200 F). This session will present the results of full-scale and sub-scale tests conducted on an incoloy overlay (ID) pipe at high temperatures (350 and 400 F).
- **Case Study: Geophysical/Geological Applications Used to Address HPHT Drilling Hazards Pre-drill and Post-drill, Jaguar-1 Well, Offshore Guyana** – *Allan Kean, Repsol*
  This case study examines several different approaches to predicting extreme pore pressure when even more extreme pressure is encountered than what was originally predicted as "the worst case scenario."
- **Integrating DPR with Real Time Monitoring System for Digital Field Application: Key Enablers for Strategic Production Optimization of Wells Producing from Deep HP-HT Sour Carbonates in North Kuwait** – *Bhavadip Navinchandra Vaidya, Kuwait Oil Company*

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For more information about the event: Melissa Smith, Director of Events, at +1 (713) 520-4475 or Melissa.Smith@GulfPub.com

For exhibit or sponsorship opportunities: Contact your local representative or Ron Higgins, Publisher and Vice President of *World Oil,* at +1 (713) 529-4301 or Ron.Higgins@GulfPub.com

HPHT Drilling and Completions Conference 2013 Pricing:

Registration Type	Regular Price
Single Attendee	$990
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- Latest advancements in well construction, valve and casing design, proppant selection and water treatment
- Future of shale development on an international scale

www.ShaleTechconference.com

■ JOHN BETZ, Associate Editor

Gulf Publishing Company's fourth, annual ShaleTech conference serves as a specialized forum, which focuses the industry's wide range of upstream activities to the increasingly important recovery of shale oil, gas and condensate. This conference provides opportunities for creators of new shale exploitation technologies to meet and network with those companies who are looking to put such technologies to work in the field.

From spudding to production, all stages of upstream, shale play development will be discussed in the extensive two-day lecture series. The conference's keynote speakers include Texas Railroad Commissioner David Porter and oil and gas consultant David Blackmon. Mr. Blackmon is managing director of FTI Consulting. Mr. Porter became Texas Railroad Commissioner in 2010, after a successful career of providing accounting and tax services to oil and gas producers. Porter will speak in the morning of the first day, Blackmon will speak on the following morning.

ShaleTech attendees will have the opportunity to register for an exclusive pre-conference workshop on Aug. 28, hosted by Ali Daneshy, president of Daneshy Consultants Int'l, Inc. This year's workshop is titled "Advanced hydraulic fracturing: Beyond the basics." Attendees will learn new guidelines for better fracture designs that lead to superior production enhancement at lower cost. Built on actual field data, this workshop steps beyond simple theory and offers new insight on the topics of fracture initiation, extension, closure, proppant transport, conductivity and screen-outs.

The conference will be held August 28–30 at Norris Conference Centers – City Center in Houston, Texas. WO

David Porter, Texas Railroad Commissioner (left); David Blackmon, Managing Director, FTI Consulting.







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ADVANCES IN COILED TUBING

Coiled tubing technology has advanced significantly since the days of skid-mounted units (pictured). Today's advanced coiled tubing systems can transmit accurate, real-time downhole data to significantly improve efficiency and accelerate well recovery in multiple operations. Photo courtesy of Baker Hughes.

SPECIAL SUPPLEMENT TO
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> New Red Deer, Canada Service Center Now Open

Continuing improvements enhance CT reliability and applications

PRAMOD KULKARNI, Editor

World Oil is pleased to present the 2013 edition of its annual coiled tubing (CT) supplement. Since their introduction to the oil and gas industry in the 1960s, CT applications have increased over the decades through improvements in tubing metallurgy, advances in rig designs and the development of small-bore downhole tools, such as rib-steered drilling motors. CT is now a cost-effective intervention tool with multifaceted reentry drilling, completion and production stimulation capabilities, with new applications emerging for formation evaluation, shale fracturing, fishing, and even plugging and abandonment, both onshore and offshore.

Routine CT use for intervention depths beyond 20,000 ft, and even as deep as 35,000 ft, is made possible through metallurgical improvements by tubing manufacturers to strengthen mechanical properties of the tubing, and achieve better fatigue performance in the tube body and the bias weld. To ensure reliability, computer modeling can be used for fatigue testing under simulated field conditions. Tubing made out of corrosion-resistant alloys is available for extreme CT operations in downhole formation fluids that have a high water cut or corrosive CO_2/H_2S content. WO

TeleCoil intelligent CT service provides real-time downhole monitoring of depth correlation, differential pressure and temperature. Photo courtesy of Baker Hughes.



INSIDE THIS SUPPLEMENT

C-130 **Using CT and sliding sleeves to reduce water usage in multi-stage fracturing.** An article by NCS Oilfield Services and Tundra Oil & Gas describes how fracturing techniques using CT have dramatically reduced the amount of frac water required, while delivering equivalent or superior results. These techniques combine CT with sliding sleeves and resettable frac isolation. CT provides a means of circulating fluids to the frac zone, as opposed to bullheading, and enables the sliding sleeves to be shifted mechanically without using pump-down balls.

C-134 **Lessons learned from CT stimulation of sour gas-producing wells at Ghawar field.** An article by Saudi Aramco and Halliburton authors explains how CT was used for challenging acid stimulation of deep, HPHT sour-gas multilateral wells. The inclusion of friction reducers for extended-reach CT application, combined with the introduction of a larger-OD CT, improved access to the zones of interest. The redesign of the isolation sleeve for the jetting tool reduced the number of required trips when obstructions were encountered, including improved use of steering tools to access target laterals.

C-141 **What's new in coiled tubing.** The lead item in this section concerns Sanjel's CT use to perform clean-out of a Bakken shale well at a record 20,783 ft total depth, consisting of a 10,000-ft vertical section with lateral sections extending to 17,783 ft. Before reaching final depth, Sanjel successfully milled out 26 plugs in single trip within 48 hr. Other new items in this section include NOV's QT-1300 tubing with min. yield strength of 130,000 psi and continuous length of 35,000 ft, and an AXON CT injector that is designed to ease operation and maintenance.

Using CT and sliding sleeves to reduce water usage in multi-stage fracturing



Multistage frac job by NCS Energy Services under way at a Bakken well, in the province of Manitoba. Photo courtesy of Tundra Oil & Gas.

Using frac sleeves, with a CT frac (half-straddle) method, to place multi-stage treatments in horizontal wellbores, lowers completion costs while reducing negative perceptions about fracing operations by surrounding communities.

DANIEL SCHLOSSER and L. LAUN, NCS Oilfield Services; and CRAIG LANE, Tundra Oil & Gas

With increased hydraulic fracturing activity, more fluid is hauled to the wellsite, pumped into fracturing operations, produced back to the surface and finally hauled to a disposal facility.

The public perception of the fracturing process is typically not based on facts, but rather on what they see and hear.

Reducing the amount of fluid required to complete a well not only reduces traffic on the roads, but it also reduces costs for the entire completion of the well. Reduced traffic, fewer tanks on location, and reduced time that the fracturing equipment is on location should improve public perception of fracturing operations.

In certain areas, there has been a move to increase the number of frac stages in each wellbore and decrease the size of each frac. This is because of reduced spacing between frac stages, as well as horizontal sections of the wells increasing in length. Typically, when operators increase the number of stages, the time required to complete the fracturing process increases, as does the total fluid requirement, due mainly to the pad and flush volumes for each stage.

BACKGROUND

Currently, the most common horizontal fracturing completion systems are plug & perf, ball-drop frac sleeve with external casing packers, cemented liners with burst ports, or perforated. When used in conjunction with CT fracturing, cemented and uncemented liners with annular fracturing systems (mechanical isolation, sand perforate & frac, or mechanical isolation and frac sleeves), they offer unique opportunities for reducing fluid requirements. Each of these systems has pros and cons, for each area of its deployment. The best system for any area (assuming a consistant frac design) is one that offers reduced frac time, lower fluid volumes, reduced costs, and contingencies for when the fracturing treatment does not go as planned.

Coiled tubing frac/sliding sleeve description. CT sliding sleeves are run as part of the casing or liner-string, and are either cemented into place, or in conjunction with external casing packers. The sleeves have the same ID as the casing-string, so no restrictions are added to the wellbore. There is no limit to the number of sleeves that can be run in a completion.

The sleeve used in this study (**Fig. 1**) was made up of only four major components: top and bottom subs, inner barrel and outer barrel. The inner barrel is made up of the same size and weight casing as run in the well.

To operate the sleeve, an isolation packer assembly is run and set in the sleeve. The wellbore is then pressured up, to supply a downward force on the BHA. This shifts the inner barrel down and exposes the frac ports.

Isolation packer assembly. The isolation packer assembly is typically deployed on CT, and is a modified, continuous-J, compression-set packer assembly, with a mechanical sleeve locator below the packer, to ensure depth control. Above the packer, the BHA contains an equalizing valve, abrasive perforator, frac port, centralizer and CT connector.

If there is a frac sleeve placed for the first zone, a compressible fluid below

Fig. 1. The sliding sleeve used in this study has four major components.

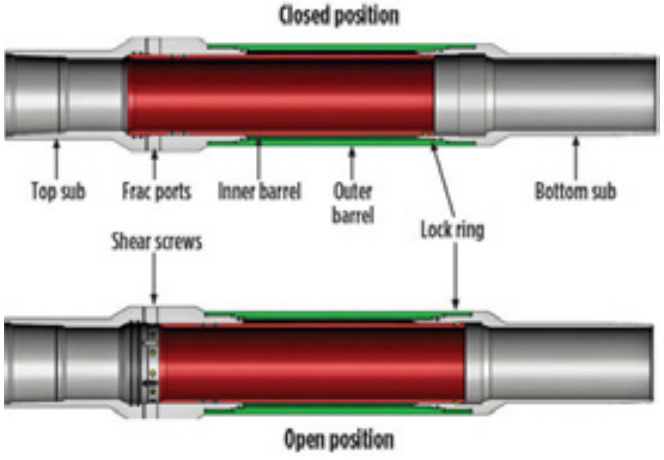
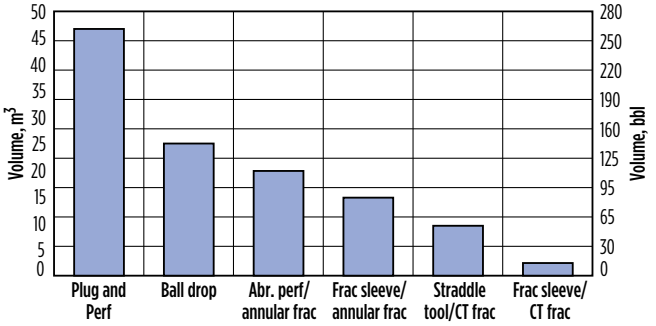


Fig. 2. Minimum, combined pad and flush volumes for various fracturing methods.



the packer is necessary, or a flow path, by which fluid can be displaced from the area below the packer. This is often accomplished through the deployment of a decompression sub at the bottom of the BHA, to give the fluid in the wellbore a flow path, while the sleeve is shifting downward in the wellbore. If the first zone is not initiated via a frac sleeve (burst port, abrasive perforated, etc.), the decompression sub is not required.

Horizontal multi-stage fracturing methods. The plug & perf completion method is used in cased wellbores. The first zone is perforated with a TCP gun, and the frac placed down the casing. A wireline, bridge plug and perforating assembly is then pumped into the wellbore, and the bridge plug is set below the next perforating interval. The tools are pulled up, the next interval is perforated (typically multiple sets of perfs), and wireline is pulled from the well. A frac is then placed in the newly perforated zone. This procedure is repeated up the wellbore. Once all zones have been treated, the bridge plugs are milled out, typically with CT.

This completion technique uses a considerable volume of water, because the wireline tools need to be pumped down to the perf interval, and the frac is placed down the casing, so a wellbore volume of fluid is injected into the formation ahead of each pad. If multiple sets of perforations are used per interval, it is impossible to know where the frac and sand is placed, possibly leaving reserves behind. This method requires multiple runs into the wellbore, with CT (perforating zone 1, milling the bridge plugs), and is very time-consuming.

Ball-drop frac sleeve completions are used more widely, because they can be used with high-rate and low-rate fracs. Ball seats are run between external casing packers, with seat sizes increasing in diameter, from the toe to the heel. A burst port is run for the lowest zone. During fracturing operations, the first frac sand is pumped, followed by a fluid spacer. A ball is dropped in the spacer fluid and pumped down the well. The ball will lodge in the corresponding ball seat and seal off the well. A pressure-increase forces the ball seat down, opening the port and the next frac is placed. This system has a limited number of stages that can be installed into a wellbore because of the limited seat sizes available.

Ball-drop frac sleeve completions are expensive to install, due to all the external casing packers required. In case of screen-outs, a CT clean-out can be complicated and difficult, because of all the restrictions placed inside the wellbore.

Another completion technology is cementing a liner assembly into a well. The liner can incorporate burst assemblies, or can be pre-perforated with TCP guns. CT is run into the well with straddle tools. The first burst assembly and set of perforations is straddled, and the fracture treatment is placed down the CT. This method is designed for reduced-rate treatments. With this method, the flush fluid is squeezed ahead of the fracture treatment, prior to the pad reaching the formation.

Another popular method for cemented and uncemented liners is mechanical isolation, conveyed on CT and abrasive perforating or with frac sleeves, and fracturing down the annulus of the CT and casing. The CT reduces wellbore volume, which reduces the amount of fluid that is squeezed ahead of the frac. The CT is in the well, so in the case of a screen-out, the sand can be circulated out of the well by pumping down the CT.

This method can accommodate low-to-medium-rate fracture treatments, depending on completion and CT sizes. Once all fracturing operations are completed, the wellbore is left full drift, without milling operations.

Coiled tubing fracturing with frac sleeve (half-straddle) procedure. An optimized method for completing multi-stage fracturing operations was created by combining the best features from the above methods into one system. This system has the advantages of fluid savings seen with fracturing down CT, the circulation options seen with annular fracturing (including being able to circulate the frac down to the BHA), and the ability to apply abrasive perforation to any zone, while leaving the wellbore for drift ID.

The first stage of this system occurs with the running of the sleeves as part of the final completion. If the sleeves are being used in conjunction with external casing packers, the frac sleeves typically replace the ball-operated sleeves' locations.

The majority of the sleeves deployed, to date, have been cemented into the well. This allows the operator to know exactly where the fracture is initiating, thus ensuring proper drainage of the reservoir. The cementing procedure remains the same as the typical cementing procedure, since the sleeves cannot open during cementing operations. Aside from physical space, there is no limit to the number of frac sleeves that can be installed in a well.

During hydraulic fracturing operations, the BHA is connected to the CT and is run in to the bottom of the well.

Table 1. Frac sleeve & CT frac (half-straddle) sand schedule per stage.

	Stage volume, m^3 / bbl	Density start, kg/m^3 / PPA	Density end, kg/m^3 / PPA	Stage tonnage, tonne / lb
Pad	2.0 / 13			
Proppant stage #1	3.7 / 23	100 / 1.0	330 / 2.5	0.80 / 1,765
Proppant stage #2	3.7 / 23	330 / 2.5	570 / 4.5	1.67 / 3,680
Proppant stage #3	3.7 / 23	570 / 4.5	800 / 6.5	2.53 / 5,580
Flush	–	–	–	–
Total	13.1 m3 / 82 bbl			5.0 t / 11,023 lb

Table 2. Fluid and sands summary for 29 frac stages.

Method	Average fluid stage volume, m^3 / bbl	Total, 29-stage, fluid volume, m^3 / bbl	Total sand, tonne / lb	Pumping time, hr
Ball drop frac sleeves	33.9 / 213	983 / 6,183	145 / 319,670	45.5
Abr. perf / Annular frac	29.2 / 184	847 / 5,327	159.5 / 351,640	53.7
Frac sleeves / Annular frac	24.2 / 152	702 / 4,415	145 / 319,670	32.5
Straddle tool / CT frac	20.1 / 126	583 / 3,667	145 / 319,670	27.0
Frac sleeves / CT frac	13.1 / 82	380 / 2,390	145 / 319,670	17.6

Table 3. Comparative costs for different fracing methods.

Stages per well	Sand per stage, tonne / lb	C$/well	C$/tonne	C$/stage	Fluid used per well, m^3 / bbl	Fluid used per stage, m^3 / bbl
Frac sleeves with annular frac						
24	4.25 / 9,370	$251,000	$2,461	$10,458	656 / 4,126	27.3 / 172
23	4.0 / 8,820	$217,000	$2,359	$9,435	623 / 3,919	27.1 / 170
25	4.0 / 8,820	$278,000	$2,780	$11,120	774 / 4,868	31.0 / 195
24	3.75 / 8,270	$211,000	$2,344	$8,792	850 / 5,346	35.4 / 223
22	3.5 / 7,720	$197,500	$2,565	$8,977	719 / 4,522	32.7 / 206
24	4.5 / 9,920	$270,000	$2,500	$11,250	686 / 5,460	28.6 / 180
Average 24	Average 4.0 / 8,820	Average $237,417	Average $2,502	Average $10,005	Average 718 / 4,516	Average 29.9 m^3 / 188 bbl
Straddle tool with frac through CT (6 wells)						
Average 24	Average 4.0 / 8,820	Average $207,500	Average $2,210	Average $8,704	Average 634 / 3,988	Average 26.4 m^3 / 166 bbl
Frac sleeves with CT frac (half-straddle)						
22	3.75 / 8,270	$158,800	$1,925	$7,218	445 / 2,799	20.2 / 127
25	4.25 / 9,370	$175,000	$1,647	$7,000	595 / 3,742	23.8 / 150
19	4.25 / 9,370	$161,000	$1,994	$8,474	462 / 2,906	24.3 / 153
24	4.25 / 9,370	$170,000	$1,667	$7,083	470 / 2,956	19.6 / 123
22	4.0 / 8,820	$165,000	$1,875	$7,500	361 / 2,271	16.4 / 103
13	4.0 / 8,820	$100,870	$1,940	$7,759	315 / 1,981	24.2 / 152
23	3.6 / 7,940	$143,000	$1,727	$6,217	467 / 2,937	20.3 / 128
24	4.9 / 10,800	$164,642	$1,400	$6,860	682 / 4,290	28.4 / 179
22	3.8 / 8,380	$126,276	$1,510	$5,740	505 / 3,176	23.0 / 145
Average 22	Average 4.1 / 9,040	Average $151,621	Average $1,743	Average $7,095	Average 478 / 3,007	Average 21.7 m^3 / 136 bbl

To reduce frac standby costs, the frac crew typically arrives on site, once CT is on bottom, and the tool is pressure-tested.

The frac sleeve is located using a mechanical sleeve-locator, and the packer is set in the frac sleeve. The well is quickly pressure tested, to ensure the integrity of the wellbore, and the well is pressured up to a shifting pressure of 1,450-1,750 psi differential pressure, to shift the sleeve open. A shift signature, seen on surface, via the CT weight, indicates the sleeve has opened, as well as a pressure bleed-off in the annulus.

Once the frac sleeve is open, the first frac is then circulated down the CT, with the annulus open. The return fluid is stored in a separate tank and will be used for flushing the frac. With the pad of the frac at the BHA (or acid spearhead, if used), the annulus is shut in, and the frac is pumped into the zone.

With the frac completely flushed into the zone, CT pulls up on the tool, which opens the equalization valve. Continuing to pull on the tool releases it. Then the tool is pulled up to the next location. Using the mechanical sleeve-locator, the next sleeve is located, and the tool set in the sleeve.

This process is repeated for the remaining sleeves in the well. With all zones completed, the CT and BHA are retrieved from the well, leaving a full-ID completion behind.

If perforating another zone between two sleeves is required, a ball is simply pumped down to the BHA and landed in the top of the frac port, isolating off the perforator. The perforations are cut, and the ball is reverse-circulated back to the surface.

Fig. 2 shows a comparison of the minimum, per-stage, combined pad and flush volumes, for the different completion methods used in the southeastern Saskatchewan area of the Bakken. This chart assumes 5.5 in. casing, 2.0 in. CT and a frac depth of 6,562 ft.

The Bakken formation in this area does not require a large pad to successfully place fracs; ideal pad volumes are typically less than 13 bbl. Pad volumes above 13 bbl consume unrequired fluid, which is pumped into the formation, increasing the frac height (which is undesirable, due to a water-bearing formation located above the Bakken). This increases the water volume required for fracturing, and ultimately increases operation costs.

Using CT fracturing, in conjunction with frac sleeves, lowers total fracturing fluid volumes by as much as 50%, compared to a ball-drop system, and 30% compared to annular fracturing using frac sleeves. This depends on frac design (pad requirement, sand tonnage and concentration, etc.) for the particular area. Pump time of the fracture treatments and the frac chemical volume also decreases with the reduced fluid volumes (**Table 1**), allowing for a significant cost-reduction. The plug & perf method of multizone-fracturing is not commonly used in this area, due to the large amounts of fluid required, and the costs associated with this technique.

Aside from the operational costs of hauling; fracturing chemical additives; and storing and disposing of the additional fluid volume, there is a social cost to using this extra fluid. Residents of the area see the large storage tanks on the wellsite; notice trucks traveling up and down their roads; hauling the fluid into location; and witness the large frac crew pumping the fluid down into the well, in a short amount of time.

With fresh water supplies becoming increasingly scrutinized and monitored, reducing the amount of water pumped

into the ground to produce oil and gas has also become increasingly important. With fewer water trucks hauling water down local roads, not only is it safer for the residents, but the operations are less likely to impact the residents' lives in a negative manner, by conserving this vital, natural resource.

EXAMPLE WELL

Below is a sample well, in the Bakken formation, in southwestern Manitoba, Canada. The well has the following parameters:

- Measured depth of 7,874 ft
- True vertical depth of 3,445 ft
- Casing: 5.5 in., 15.5 lb/ft
- CT: 2⅞ in., 0.190 in. WT; length 8,859 ft,
- volume 53.5 bbl
- 29 frac stages

The parameters for the frac treatment are:

- Rate of 5.7 bbl/min
- Water frac fluid, linear pads, cross-linked sand stages
- 5 tonnes of 20/40 sand

If we compare the total volumes of the 29 stages, for the different methods commonly used in the area (Table 2), one can see why the area shifted from using the ball-drop frac sleeves, through the different methods, ending up with the frac sleeve and CT method. The change from the ball-drop system to the abrasive perforation, with annular frac, was also driven by the significant completion cost reduction, of going from external casing packers, to a cemented system.

The shift from an abrasive perf with annular frac, to frac sleeves with annular frac, saw a significant time savings for fracturing operations, as it eliminated the perforating stage, saving 25 to 35 min. per stage. There is also a fluid savings of not having to pump the perforating fluid. If perforating fluid is not circulating, more of the flush can be used as pad for the next zone.

The change from frac sleeves with annular frac, to straddle tool with CT frac, saw fluid savings and a minor time reduction. Contingencies for sand-offs are limited, as the sand could only be reverse-circulated from the wellbore. All fluid inside the CT must be squeezed into the zone, ahead of the frac.

The process of CT fracturing, using frac sleeves, saw a large fluid savings and a significant time savings, as well. The cost savings of using a lower volume and quicker pump time were increased above the fluid cost, since the time to pump a 29+ stage frac was now less than 24 hr. This meant one less crew shift for everyone on site.

CASE STUDY: 21 WELLS

Table 3 shows a comparison of 21 wells, which were completed using frac sleeves with annular frac, straddle tool with CT frac, and frac sleeves with CT frac methods. The fluid volume is the total volume that was used in fracturing operations, including any circulation cleanouts, etc.

The frac ticket cost reduction generated by the frac sleeves with CT Frac method, compared to the frac sleeves with annular frac method, is $2,910 per stage, for a reduction of 29.1%. The same methods comparison shows a fluid volume reduction of 8.2 m^3 per stage, for a 27.4% fluid reduction.

The frac sleeves with CT frac method, when compared to the straddle tool with CT frac method, shows a frac ticket cost reduction of $1,609 per stage, which equates to 18.5%. The corresponding fluid volume reduction for the comparison of these two methods is 4.7 m^3 per stage, or a 17.8% reduction in fluid volume.

For a 24-stage wellbore, the frac sleeve with CT frac method saves $70,000 in frac ticket costs, and 1,258 bbl of fluid, when compared to frac sleeves with annular frac. The fluid volume equates to approximately seven truckloads of fluid brought to the wellsite, with additional reduction in trucking for the fluid leaving location. There are cost savings associated with the lower truck traffic, and less tankage onsite, which are in addition to the frac ticket savings.

CONCLUSION

Using the frac sleeve with CT frac (half-straddle) method, to place multi-stage fracture treatments in horizontal wellbores, lowers completion costs significantly, lowers water usage for fracturing operations, and enhances the public image of oil and gas operations. This method is the environmentally-conscious way to do multi-stage fracturing, where design allows. WO

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Lessons learned from CT stimulation of sour gas-producing wells at Ghawar field

Corrosive environments, limited coiled tubing reach, steering tool assembly requirements and precise fluid placement limitations call for special solutions.

MUSTAFA R. AL-ZAID, MOHAMMED S. AL-GHAZAL, FADEL AL-GHURAIRI, and SAAD M. AL-DRIWEESH, Saudi Aramco; JOSE VIELMA, ALEJANDRO CHACON and JOSE NOGUERA, Halliburton

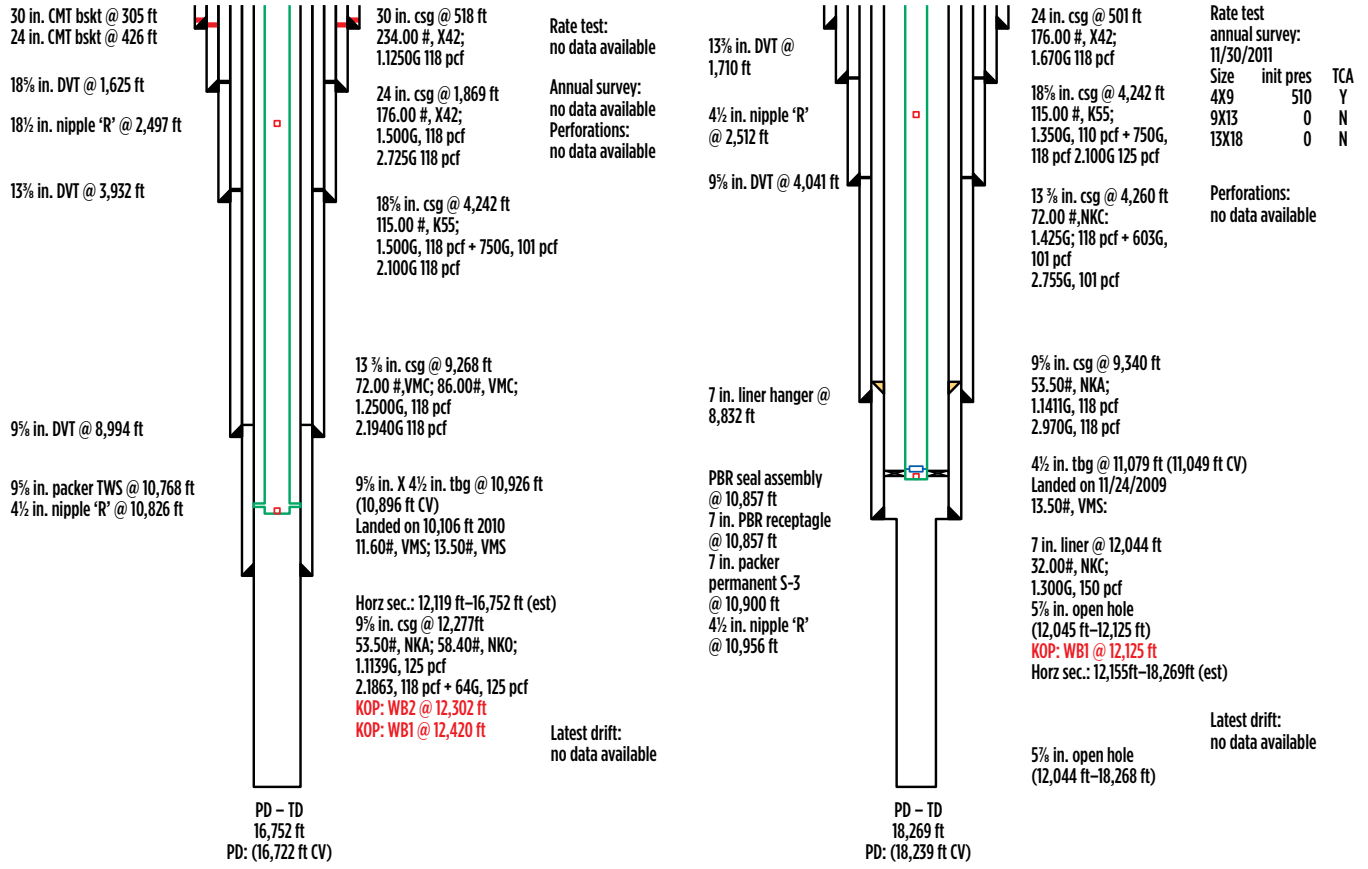
Coiled tubing (CT), acid stimulation interventions in openhole, multilateral wells represent one of the industry's most challenging scenarios. Factors, such as a corrosion, CT limitations, steering tool assemblies and fluid placement, all require innovative solutions to maximize well productivity.

In recent years, the number of openhole, multilateral wells drilled in Saudi Arabia has increased significantly. Consequently, this initiative has also increased the requirements for performing acid stimulations, and for enhancing well productivity. A solution to this problem needs to address the corrosion challenges associated with pumping high acid concentrations, in sour and high-temperature environments; reaching target depths, in multiple laterals, with complex well architectures; the use of effective steering tool assemblies to access multiple laterals; and the placement of acid stimulation fluid systems in target zones, across the open holes, to maximize well productivity. This article documents the engineering solutions developed to address these specific challenges.

WELL ARCHITECTURE

Well architecture is key in determining the type and size of CT and downhole tools to be used during well interventions. It is also important for defining the stimulation strategy (especially in multilateral openhole completions), as well as for

Fig. 1. Typical diagrams of multilateral, gas-producing wells in Ghawar field.



evaluating whether CT can reach the targeted depth, in extended-reach horizontal wells. The multilateral, HPHT, sour gas-producing wells drilled in Ghawar field are generally completed as per the configuration shown in **Fig. 1.**

These two completions vary in casing size used and setting depth, utilizing 4½ in. to 13½ lb/ft tubing in all cases, with a minimum restriction of 3.688 in. (R-nipples). Openhole lateral diameters also vary from 5⅞ in. to 8⅜ in., depending on the internal diameter of the last casing (6.094 in. for 7 in.-liner and 8.535 in. for 9⅝-in. casing). The angular build-rate starts from 9,000 ft to 10,000 ft MD, with a maximum dogleg kept under 10°/100 ft; a maximum inclination of ~90° is reached, approximately 500 ft below the deepest casing shoe MD (although in some cases, the maximum inclination is located above the production liner/casing shoe). **Figure 2** shows a lateral deviation and azimuth. TVDs vary from 11,500 ft to 13,000 ft. The number of laterals drilled may also vary, and in some wells, two openhole laterals are drilled, but in some other cases, as many as three laterals are drilled (although only two laterals are treated). **Table 1** shows a summary of treated openhole section lengths during the CT stimulation campaign.

FORMATION DESCRIPTION

Wells described in this paper were completed as multilateral, openhole completions, leveraging on the Khuff consolidated carbonate formations. The minerology of the targeted zones is mainly calcite, with strakes of dolomite. Other important reservoir parameters are:

- Reservoir pressures ranging from 4,500 psi to 6,500 psi.
- Target depth TVDs from 11,500 ft to 13,000 ft.
- Formation permeability averaging at 0.2 MD.
- Bottomhole temperatures (BHTs) ranging from 250°F to 300°F.
- Formation fluids: gas condensate of 40° to 45° API; condensate gas ratio from 50 bbl/MMscfd to 150 bbl/MMscfd.
- H_2S concentration varies from 1% to 10%, and CO_2 concentration from 1% to 4%.
- Net pay defined as per zones with a porosity >5%. Net pay length average is around 50% of total lateral length.

Fig. 2. An example of multilateral, gas well construction.

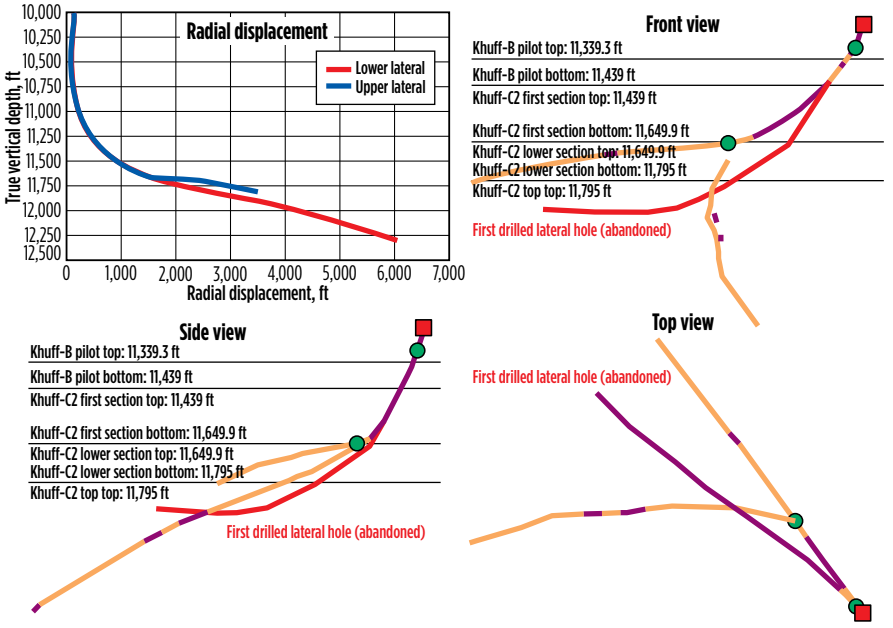


Table 1. Openhole section lengths.

Well	Liner/Casing depth MD, ft	OH diam.,ft	OH lateral 1 length, ft	Total length, MD, ft	OH lateral 2, length, FT	Total length, MD, ft
A	12,162	8.375	4,406	16,538	5,296	17,458
B	12,044	5.875	2,455	14,499	6,224	18,268
C	11,825	8.375	2,775	14,600	6,135	17,960
D	12,277	8.375	3,061	15,338	4,091	16,368
E	12,360	5.875	2,751	15,111	5,115	17,475
F	12,246	5.875	2,324	14,570	3,175	15,421
G	13,106	8.375	2,388	15,494	6,724	19,830
H	12,013	5.875	2,589	14,602	3,189	15,202
I	12,798	5.875	2,102	14,900	3,508	16,306

MULTILATERAL WELL INTERVENTION CHALLENGES

Dual-lateral, openhole configurations, when combined with extended reach and corrosion issues, carry with them complex challenges. In this case study, detailed analysis and pre-job engineering work were carried out to develop the best technical solution, without compromising the overall goal of being able to stimulate all the desired zones. Therefore, besides being able to reach further along an openhole section, it was necessary to combine a set of tools that can aid in identifying and steering the BHA into an alternate lateral, maintaining the option of placing the fluid with the hydrajetting tool, for precise fluid placement. This section documents the solutions developed to tackle these challenges.

Challenge #1—Corrosion concerns in acidic fluids and sour environments. When dealing with extreme acidic fluid systems, such as 26% hydrochloric (HCl) acid, in hot wells producing up to 100,000 ppm of H_2S and 3% CO_2, tubular and CT string corrosion mitigation and prevention, become of paramount importance and quite challenging tasks. Corrosion is one factor that dramatically affects CT string-life, as well as downhole tools/equipment integrity. Among important factors to evaluate, when working in acidic and sour environments, are:

- CT steel properties (CT grade, hardness, weld type)
- CT string management such as: Accumulated fatigue, accumulated acid exposure, ovality, pitting, wall thickness losses, cracks, etc.
- Connector and downhole tool material selection
- Elastomer selection
- BHT and bottomhole pressure (BHP)
- Exposure time to acidic and sour environments.
- Concentration of sour gases

- Stimulation acid type and concentration.

Hydrocarbons containing acidic gases, such as, H_2S and/or CO_2, can be corrosive to CT, due to pH reduction, as described by Hampson et al.[1] Low-pH, aqueous fluids, when subject to high temperature, accelerate corrosion by providing a plentiful supply of hydrogen ions. Any brine in the production fluid will also increase the overall corrosiveness to the CT, as well as provide an aqueous medium for contamination. In other words, aqueous fluids become very corrosive in the presence of H_2S and CO_2 gasses, inducing sulfide stress cracking (SSC) on tubulars. Use of highly-concentrated, inorganic acids (i.e., 26% HCl) for carbonate dissolution further intensifies tubular corrosion concerns, so the appropriate, tested selection of corrosion inhibitors and intensifiers is important under these conditions.

During this CT stimulation campaign of multilateral, openhole, HPHT, sour gas-producing wells at Ghawar field, many actions have been taken to minimize or mitigate corrosion issues on completion and CT strings. Among these, the following measures taken both in the lab and on the field:

Loading the well with treated water, prior to running CT in hole. This has been done mainly to reduce wellhead pressure and/or kill the well, so H_2S migration is minimized. The treated water is prepared by mixing fresh water with 0.2 vol% non-emulsifying surfactant, 5% mutual solvent, and 0.2 vol% of SSC inhibitor, which is a sulfur anti-cracking agent and forms a protective film on the pipe.

Circulating treated water loaded with SSC inhibitor while traversing the openhole section. The same treated water blend is circulated to keep the outside of the CT string coated at all times, with the SSC inhibitor, when running CT in hole.

Extensive corrosion tests on CT and completion material coupons. Laboratory corrosion evaluation was performed, utilizing QT-900 and N80 coupons, with 26% HCl and 15% HCl, in sweet conditions, as well as in 2% H2S sour conditions, for at least 6 hr. of contact time, and at a maximum temperature of 275°F. During the corrosion-rate evaluation, several corrosion inhibitors, corrosion inhibitor intensifiers and sulfide, anti-cracking, acid-soluble agents were tested at different concentrations, until the desired corrosion rate was below the 0.05 lbm/ft^2 threshold. As stated by Nasr-El-Din et al.,[2] When using CT strings, where the thinner wall thickness is in front of the producing zone and subject to more frequent exposure to corrosive environments, there is a more stringent weight loss limit of less than 0.02 lbm/ft^2.

Using a non-acidic, solids-free diverter, to minimize fluid losses from thief zones. The use of in situ, viscosity-controlled acid, such as systems loaded with viscoelastic surfactants and/or cross-linked gelling agents, depends heavily on formation rock reactivity properties. If the formation shows low reaction rates when coming in contact with acid, the aforementioned type of diverter will increase CT exposure time to live acid. Thief zones can be located in any section of the open hole to be treated, as well as in alternate laterals. Thus, there is a need for effective diverting agents in these operations, to aid in a uniform acid distribution along the zone of interest. The use of associative polymers as a diverting agent, in matrix acidizing and acid fracturing operations, has been described by Nunez, et al.,[3] and Solares, et al.[4]

Minimizing CT exposure to sour and acidic fluid influx. After each lateral is stimulated, and the CT is pulled out to surface, the well is flowed back to production. This is done to minimize CT exposure to partially-spent acid and/or acidic aqueous fluids. If the well is not able to flow, then CT is run in-hole (RIH) to lift the well with nitrogen circulating treated water pills, loaded with SSC inhibitor, at a 0.2 vol% concentration.

Loading acid systems with H_2S scavenger. An Aldehyde blend that acts as a sulfide scavenger and cracking inhibitor is added on the fly to all acid blends. A concentration of 1.5%, volume, is being used for anti-cracking purposes, as well as for H_2S scavenging. Scavenging H_2S from the wellbore completely is often not practical, so the concentration is usually based on lab tests that showed a decrease in general corrosion. For instance, with higher levels of H_2S, this inhibitor would not be expected to scavenge all of the sour gas, but it would reduce the corrosion significantly (Hampson, et al).[5]

Mixing acid blends before reaching targeted zones. To reduce CT exposure time to acidic and sour conditions, as well as save operational time, the required volume of acid and non-acid blends is mixed prior to RIH. Once the targeted depths are reached by the CT nozzles, the stimulation job can start immediately. If access to the openhole sections is not possible, and the targeted depths cannot be achieved by any means, the mixed acid is pumped by bullheading as a contingency plan.

Reaction rates and formation type also play a part. Low reaction rates mean that the CT string will be in contact for longer periods of time with high-acid-strength concentrated fluids. In contrast, the presence of sulfide-based scales may induce the release of an important amount of H_2S, when it comes into contact with the acid blends. During these CT stimulation operations, obstructions in the horizontal, openhole section were detected, requiring its removal by mechanical means. In these cases, a high-frequency, fluidic oscillation jetting tool was utilized to bite and penetrate the fill, pumping viscous gel pills assisted with N_2 to lift the solids back to surface. Whenever no cleanout progress was observed with mechanical means, HCl pills were spotted to attempt fill dissolution. Sometimes, this was used as a last resort measure, given the possibility of having FeS scale deposition, which would react with the HCl and generate H_2S, making it a matter of concern.

Challenge #2—CT lockup in the openhole section. Performing CT interventions, and more specifically, acid stimulations, in an extended-reach scenario, represents a significant challenge in terms of being able to reach the target depths. The wells on this study case are completed with 4.5 in.,13½ lb tubing sections, with a short section of exposed 7-in., 32 lb liner and coming out to a 5.875-in. or 6.125-in., openhole section.

This well configuration poses a problem when it comes to pipe buckling due to two main factors. One is the fact that the openhole section has a higher friction coefficient, which can be over 20% of the friction experienced in a cased-hole section. A second issue is that larger-diameter liners and openhole sections make the CT more prone to buckling, due to the larger radial clearance between the CT and the tubular/open hole.

This larger radial clearance permits a larger pitch angle of the CT, when spiraling or buckling, allowing for more contact points to be developed between the CT and the tubulars/open hole, which, in turn, increases the drag force over this section. More drag force translates into more buckling force, which develops

more contact points along the wellbore, which in turn generates more drag, turning the situation into a vicious circle, as per Terry, et al.[6] This results in lockup, where the free end no longer travels in the wellbore, and the entire CT, being pushed at surface, spirals into a helix in the vicinity, where the highest wellbore wall-to-CT contact force is experienced.

Initially, these stimulation operations were being carried out with 2-in. outer diameter (OD) CT. As the lockup problem started to occur, and the learning curve steepened, the idea of running larger-OD CT that is able to reach deeper in the horizontal openhole section before requiring the use of friction reducers and/or extended reach tools, was evaluated.

The first approach was to perform the simulations on several intervened and future wells, using both sizes of pipes, and determine the amount of extra depth that the CT could reach by itself. The results were compelling, showing that on most wells, the 2.375-in. CT was able to reach on average, an additional 1,000 ft in comparison to a 2-in. string. The theory behind the additional reach provided by the larger pipe, granted that they have the same tapered wall thickness configuration, is that the larger-OD of the 2.375 in.-CT will have a higher bending stiffness value (E×I, where "E" is the Young's modulus of the material, and "I' is the area moment of inertia. See equations below:

$$E = \frac{\sigma}{\varepsilon} = \frac{\text{tensile stress}}{\text{tensile strain}}$$

$$I = \frac{\pi \times \left(d_o^4 - d_i^4\right)}{64}$$

This higher bending stiffness value means that the larger pipe is "harder" to bend than the smaller pipe, so having a smaller helix angle (θ) when buckling, allowing for a longer spacing of contact points between the pipe and the wellbore when it begins to spiral. This, in turn, dictates that a higher compressive force is required to buckle the pipe. Although the use of 2⅜ in.-CT will increase the reach, it was not a stand-alone solution to the lockup challenge. The CT simulation also had shown the need for friction-reducer. A viscoelastic surfactant (VES)-based drag friction-reducer was utilized to reduce the friction by an average of 25% between the CT and wellbore. In some cases, where the CT locked up prematurely, and had covered less than 50% of the openhole length, it was decided to spot and circulate the VES-based friction reducer with commingled nitrogen, to reduce the pipe weight, thus reducing the normal force acting between the wellbore and the pipe. In all lockup cases, an additional reach of over 1,500 ft in the openhole section was experienced, enabling the delivery of acid treatment to the deepest zones of interest in the

Fig. 3. The effect of friction-reducer on pipe weight is evident in these charts.

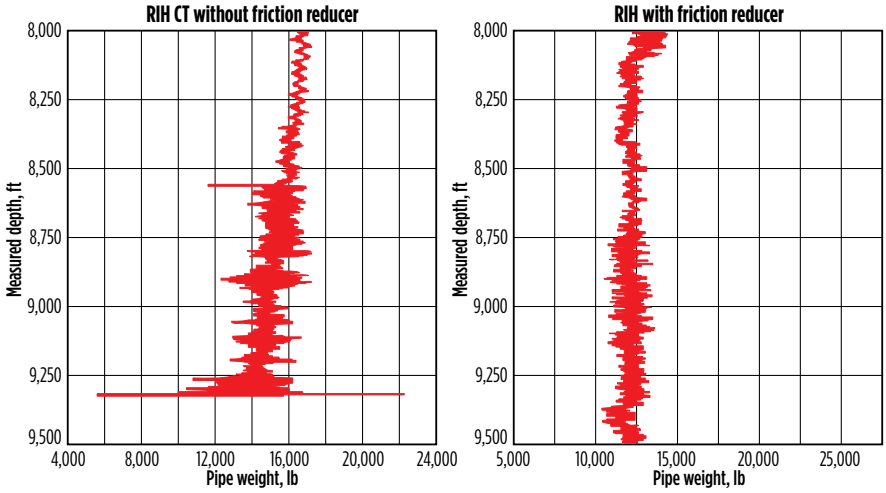


Fig. 4. Friction-reducer used in a horizontal, openhole section.

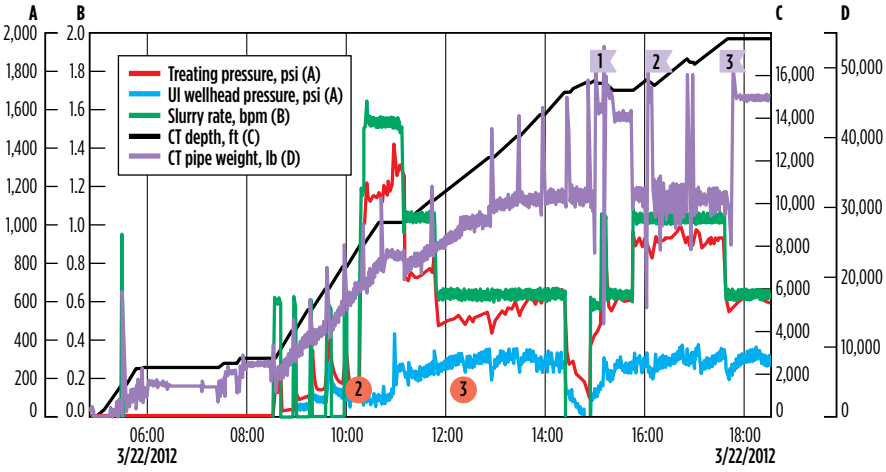


Table 2. Yard test results for steering tools and sleeve system.

Nozzle size/Type	Flowrate	Pressure	Tool behavior
Steering tools and adjustable nozzle	1.2 bbl/min	1,300 psi	Rotational sub rotated 30° and bent sub fully activated
Sliding sleeve system (ball drop)	1.0 bbl/min	3,200 psi	Sliding sleeve sheared to isolate steering tools and flow through the hydrajetting tool

Table 3. Yard test results for steering tools and sleeve system.

Nozzle size/Type	Flowrate	Pressure	Tool actions
Steering tools and adjustable nozzle	1.2 bbl/min.	1,300 psi	Rotational sub rotated 30° and bent sub fully activated
Sliding sleeve system (ball drop)	1.0 bbl/min	3,200 psi	Sliding sleeve sheared to isolate steering tools and flow through the hydrajetting tool.
Sequencing valve	1.6 bbl/min.	2,250 psi	Sequencing valve closes and isolates indexing tools.
Dynamic excitation tool	2.0 bbl/min.	2,800+ psi	Tool working at optimal frequency for static friction coefficient reduction.

wellbore. **Figure 3** illustrates the reduction in the "noise" of the weight indicator reading, which, in turn, indicates that the pipe is gliding smoother along the openhole section of the well.

Figure 4 shows a well that was stimulated with acid in first-quarter 2012. Three different lockup points were observed, and the friction-reducer pill was circulated to enable extended reach in the horizontal 5.875-in. openhole section. The first lockup point was seen at 15,431 ft, the second one was at 15,574 ft, and the last one was at 17,206 ft. The friction-reducer enabled the CT to reach TD, which was at 17,450 ft, meaning that more than 2,000 ft of additional reach were obtained, with the use of the VES-based system.

An additional challenge posed by one of the multilateral wells was that, in one of the laterals, even though friction-reducer was used in the simulations, the CT was still locking up before reaching TD. For this specific well, an additional tool to enable extended reach was considered, in combination with the hydrajetting tool and the steering tools. The extended-reach tool selected was a dynamic excitation tool that works by shutting and opening backflow to the tools below, which, in turn, generates pressure pulses in the CT and BHA that reduce the static friction force coefficient. This enables deeper reach on long horizontal sections, in combination with the VES-based friction-reducer.

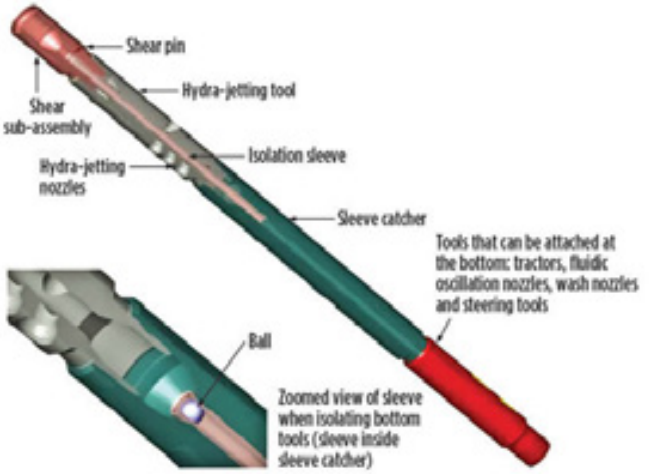
Challenge #3—Access to multilaterals. Access to the target-lateral, in a multilateral openhole completion, is perhaps one of the biggest challenges in CT interventions. Despite recent technology developments, the success ratio continues to be below the industry requirements. The set of steering tools used in this case study, has two main components. One is the controlled rotational sub, and the other is the controlled bent sub, which, when used in tandem, are able to identify the kickoff point in the wellbore.

The controlled rotational sub is flow-activated at a set pressure drop, which, in turn, is calculated to be above the circulating flowrate, to be able to RIH while circulating, without having the tool continuously rotating. Once this initial pressure drop is achieved, the toolstring below rotates 30° per cycle. Each cycle will commence only when the rate has been dropped completely, the rate is picked up again, and the set pressure drop has been achieved once more.

The controlled bent sub is installed below the rotational sub, and the activation pressure is set to be above one of the rotational subs to control the activation of each component, separately. Once the rate is picked up, and the set pressure-drop across the tool is achieved, the tool will kick up, always in the same direction, at an angle of 15°, when unrestricted. A 48-in. straight bar is installed between the bent sub and the bottom nozzle, to have the nozzle contact the wellbore. Therefore, the bar has an angle that is shallower than 15°, to have an indication of when the tool identifies the kickoff point. This indication is a drop in circulation pressure seen at surface, whenever the bending sub completes its kick, without mechanical restriction.

The operational sequence then is to RIH ~200 ft below the kickoff point mentioned in the deviation survey, stop the CT and increase the pump rate, so that the rotational sub turns, and the bent sub kicks off. The installed straight bar will make the nozzle rub against the open hole, generating a higher circulation pressure. CT is pulled out of hole (POOH), while maintaining pump-rate stability, with the tools activated, until the bent sub finds the kickoff point seen by the drop in pressure. If the bending sub is still rubbing the wellbore, at around 100 ft above the kickoff point, this means that the tool is pointing elsewhere, and not in the direction of the kickoff point. Therefore, if this happens, the pumps are stopped, CT is RIH once more and the pumps are set online again at the predetermined rate. This allows the rotational tool to gyrate at 30° once more, which changes the direction of the bent sub, to point it in the same direction as the kickoff point. The procedure above is repeated up to 12 times, to achieve full 360° coverage of the wellbore, and helps identify the tie-in point.

Fig. 5. Placement of a newly designed isolation sleeve system on a dynamic diversion tool.



Adding to the challenge to steer the CT direction into the target lateral, was the need to make the dynamic diversion tool compatible with the steering tool and, moreover, the need to carry out the stimulation in a single trip per open hole. Tool compatibility was addressed with the design of an isolation sleeve on the dynamic diversion tool, **Fig. 5.** The sleeve was designed to isolate the injection ports, while steering tools were receiving the flow from the surface, to identify the alternate lateral. Once the sleeve system was developed, the tools were yard-tested, to determine the maximum rates at which the steering tools could operate, enabling circulation while RIH, without compromising the sleeve system isolation, as this would render the steering tools inoperative. Yard tests determined the activation flowrates and pressures, as shown in **Table 2.**

Some cases required a dynamic excitation tool. These cases required a sequencing valve between the steering tools and the excitation tool, to have both systems operate independently. A yard test was performed to determine the compatibility of all tools and their independent operation. The yard tests involved the fettling and fine-tuning of the adjustable nozzles, for the steering tools, as well as the setting at which the sequential valve shut flow to the tools below, to be able to have the dynamic excitation tool work at its optimum frequency, to reduce the static friction coefficient. The yard test yielded the results shown in **Table 3.**

With the yard tests confirming the compatibility of the different sets of tools, it was possible to combine them, and to

stimulate both laterals in several wells. This was done without compromising the main goal of the operation, which was to target the best potions of the openhole section, to have the highest increments in gas production. **Figure 6** shows the final tool configuration.

Challenge #4—Selective placement of acid treatments in openhole completions. One of the most challenging tasks in horizontal, openhole stimulation operations has been to properly enable an operator to selectively place an acid treatment across the zone of interest. These tight carbonate formations require deep acid penetration. The main goal is to generate a combination, or at least to generate a network, of multiple fractures, to etch the surface of existing fractures, and/or to create extensive wormholes.[7] The fulfillment of the aforementioned objectives, on long, horizontal, openhole sections becomes a daunting task, as acid can quickly react along the openhole section, generating rock face dissolution on unwanted intervals, instead of generating fractures, or a complex network of wormholes. This previous scenario has an even higher chance of occurring, when the formation is made up mostly of heterogeneous (high contrasts in ϕ and k are found along the wellbore), highly-reactive calcite, with BHTs that frequently exceed 250°F and can go up to 300°F.

Placement of the stimulation fluid in the specific target areas, across the openhole section, was another major challenge. To achieve this, the hydrajet acid injection technique was developed, which takes advantage of the dynamics of fluid moving at very high velocity[8, 9] to direct flow to a specific entry point, in front of the nozzle. This dynamic diversion effect generates a low-pressure zone in the CT wellbore annulus, right in front of the hydrajetting tool, which draws fluid from the annulus into the jetted cavity. When the commingled fluids that enter inside the cavity hit the wall of the latter, they transform their high kinetic energy into potential energy, leaving the pressure at the tip of the cavity much higher than at the entrance. This pressure, at the outer boundary (stagnation pressure) of the cavity, can exceed annulus pressure considerably, sometimes rising more than 2,500 psi. This exceeds the fracture pressure at this point, and generates a fracture at the precise point where the nozzle is stationed. **Figure 7** gives a graphical representation, of the events that occur within the CT wellbore annulus.

Fig. 6. Specifications for a dynamic diversion tool, a dynamic excitation tool, a sequencing valve and a steering tool assembly.

BHA schematic

							Item	Tool Schematic
		Client:	Operator				1	
		Rig/platform:	2.375 in. CT Unit					
		Field/well number:	X					
		Minimum well restriction:	3.688 in.					
		Top of cement/fill/hud:					2	
		Bottom hole temperature:	262 F					
		Bottom hole pressure:	5,000 psi					
		Wellhead pressure:					3	
		Quote number:	1					
		Job number:	1					
		BHA name:	Hydrajetting + dynamic excitation tool + steering tools					
		Date drawn:					4	
	Tool description	Tool connections	Item	Tool I/D in inches	T-Length in inches	Fish neck type		
1	CT dimple connector for 2.375 in. CT	2.388 PAC pin	3.125	1.1	5		5	
2	MHA	2.388 PAC box 2.388 PAC pin	2.875	1.1	33			
3	Cross-over	2.388 PAC box 2.388 EUE pin	3	1	12		6	
4	HydraJetting tool and sleeve system	2.388 EUE box 2.388 EUE pin	3.06	1.2	22			
5	Cross-over	2.388 EUE box 2.388 PAC pin	3	1	6		7	
6	Dynamic excitation tool	2.388 PAC box 2.388 PAC pin	2.875	N/A	84		8	
7	Cross-over	2.388 PAC box 1.5 AMMT pin	3	N/A	6			
8	Rotational Sub	1.5 AMMT box 1.5 AMMT pin	2.125	N/A	60		9	
9	Controlled bent sub	1.5 AMMT box 1.5 AMMT pin	2.125	N/A	20			
10	Straight bar	1.5 AMMT box 1.5 AMMT pin	2.125	1.1	48		10	
11	Nozzle	1.5 AMMT box	2.5	-	6			
		Maxiumum tool-string OD:	3.125				11	
		Minimum tool-string ID:		1				
		Total length of BHA in feet:			25.17			

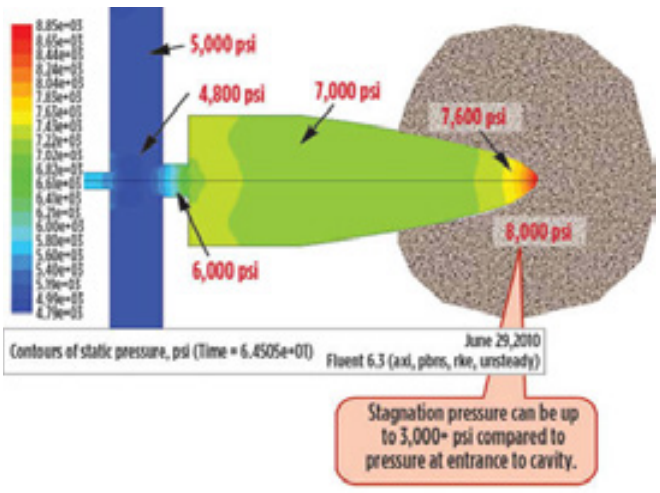


Fig. 7. Examples from laboratory testing of fractures generated by the hydrajetting technique include: a fracture caused by jetting (left); penetration caused by colored ink (center); and a larger fracture (right).

In **Fig. 8,** the hydrajetting tool was dragged while pumping weak acid at an optimal pressure drop rate, along the carbonate rock sample. The left-hand image

shows a fracture that is perpendicular to the direction by which the tool was being pulled. The center image shows how far the fractures extended, and how far the acid was injected into the rock (the trajectory of the tool was perpendicular to the plane where the measuring tape rests). The acid penetrated more than 1 ft, at surface conditions, without the aid of the annulus fluid, boosting the stagnation pressure, to enhance the fracture length. Therefore, bottomhole results are even more compelling.

To reflect a theory behind the dynamic diversion effect, and the tests run above, a sample pumping schedule was designed for the actual operation. The stages were split up into hydrajet fracturing and hydrajet squeezing sections along the wellbore, as well as combining diversion stages with an associative polymer-based fluid to have an additional measure to control losses to the thief zones. The hydrajet fracturing stages need to be done with the CT in a static position, to be able to increase the pump rate and pressure, to reach the required pressure drop at the nozzle (3,000 psi to 4,000 psi). Acid volumes placed on the hydrajet fracturing stages were usually on the order of 25 bbl to 28 bbl, to reflect an approximate equivalent of 1,050 gal/ft to 1,200 gal/ft.

The depths at which the hydrajet fracturing stages were taking place corresponded to the depths where the openhole logs showed the best porosity and permeability characteristics. This was done to bypass the damage across those gas-bearing zones with the highest production potential. The hydrajet squeeze was limited to additional intervals along the open hole that still had a good permeability and porosity profile, albeit not as substantial as the ones targeted for the fracturing stages. The hydrajet squeeze was usually performed at a rate of 3 bbl/min and 300 cfm of N_2, and at a speed of 10 ft/min., which yielded a treatment density of roughly 25 gal of acid/ft.

POST WELL INTERVENTION RESULTS

During a period of 36 months, eight multilateral wells were stimulated successfully, in spite of the challenging working conditions. Based on offset wells, with a similar type of completion, the post-stimulation production expectation for each of these wells was between 10 MMcfd and 12 MMcfd. A 70-MMcfd production increase was achieved after finalizing the stimulation campaign, exceeding post-treatment production expectations, Table 5.

Fig. 8. Examples from laboratory testing of fractures generated by the hydrajetting technique include: a fracture caused by jetting (left); penetration caused by colored ink (center); and a larger fracture (right).

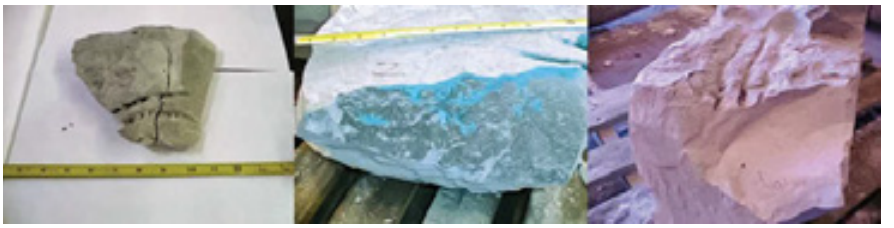


Table 5. Post-CT stimulation production results

	Pre-stimulation		Post-stimulation		
Well	Gas rate, MMcfd	FWHP, psig	Gas rate, MMcfd	FWHP, psig	Estimated gas rate gain, MMcfd
A	7	1,070	18	1,310	11.0
B	4	1,900	6.0	2,773	2.0
C	3	1,300	13.6	1,909	10.6
D	Unstable performance		24	1,530	6.0
E	9	1,087	15.4	1,318	6.4
F	3	1,300	5.0	1,060	2.0
G	9	1,230	18.0	1,200	9.0
H	6	970	17.0	1,150	11.0
I	0	240	12.0	1,480	12.0

CONCLUSIONS

Among the operational lessons learned throughout development of these stimulation interventions, several main conclusions can be drawn:

- Openhole, multilateral wells can be effectively stimulated in extremely acidic and sour conditions, without jeopardizing the CT string and well completion integrity.
- After analyzing the background pipe buckling theory, it was determined that pumping the friction-reducer while RIH, along the calculated, highest, wall contact force section (from force simulations), yielded additional reach in the lateral. This can be compared with the common practice of circulating the fluid, once the pipe has already buckled.
- Kickoff point identification depends mainly on junction and wellbore conditions. Flowback of spent stimulation fluids can deteriorate the geometry of the junction, thereby hindering lateral entry identification.
- Likewise, thief zones in the lateral that is not being stimulated can deteriorate the access junction point, minimizing the likelihood of access into this lateral, at a later stage. This is because live acid can swerve into the alternate lateral, dissolving the face of the rock at the kickoff point.
- The use of a non-acidic, solids-free diverter to minimize fluid losses to thief zones is critical to minimizing corrosion and maintaining the wellbore and junction conditions for further access into the second lateral.
- Determining required operational parameters (pumping pressure and rate) is a key factor while designing the pin configuration for the sleeve on the dynamic diversion tool. Lower-rated pins on the sleeve may shear prematurely, reducing of pumping at optimum clean-out rates, when CT is in the openhole section.
- Commingling of nitrogen in the stimulation fluid stream helped to increase delta pressure across the nozzle, and therefore, enhanced treatment penetration. In addition, energizing the stimulation fluid system significantly reduced treatment recovery time. WO

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WEB EXCLUSIVE: Please visit www.worldoil.com for references and author biographies for the article.

What's new in coiled tubing

Tubing team completes its deepest Bakken clean-out to date



In the Bakken field surrounding Williston, N.D., a typical horizontal well consists of a 10,000-ft vertical section, and a 4,000-to-5,000-ft lateral section. As drilling and completion technologies have improved, lateral sections are now reaching 9,000 to 11,000 ft in length. As a result, CT providers are now being challenged to reach these extended depths, which, in some cases, can exceed a total of 20,000 ft. Sanjel's CT team in Williston recently exceeded this depth twice.

Working on a multi-well pad for a major operator, Sanjel's CT team reached depths of 20,164 ft and 20,783 ft on consecutive wells. Lab technicians found a friction reducer fluid that significantly reduced the amount of friction between the CT and the well. This allowed the CT to deploy in its entirety and reach a significant depth, without experiencing friction lockup on the deepest well. Before reaching the final depth, Sanjel successfully milled out 26 plugs in a single trip within 48 hr.

In cases like this, considerations of extended-reach CT include proper support equipment sizing and string design, to ensure optimum performance.

CT injector design focuses on ease of operation, maintenance



Costly downtime can be minimized with oilfield equipment that is easy to operate and maintain. AXON Energy Products analyzed CT injector fundamentals and operating parameters to achieve maximum serviceability, while maintaining performance. The company's new CT injector includes external location of major serviceable components, interchangeable parts, combined assemblies and optimized skates.

All operating and tensioning cylinders are interchangeable, and located externally for ease of maintenance. The drive mechanism utilized for the chains and grippers is integrated to further minimize the requirement for CT spare parts. Additionally, the drives are mounted opposite one another, allowing for counter-rotation of the chain and grippers.

The integrated chain and gripper assembly circumvents maintenance issues, such as individual inserts and damaged screws. Simply removing the chain master link enables the entire assembly to be extracted and replaced in a matter of minutes. Fabricated from high-strength aluminum for optimal durability and weight, the skates include a replaceable, hardened wear plate, and are designed for easy removal through the side of the injector.

Combined with the CT injector's field-proven technologies, AXON's design improvements allow for ease of operation and maintenance to reduce downtime.

Tubing grade improves fatigue life



NOV Quality Tubing has developed QT-1300, a CT grade with minimum yield strength of 130,000 psi, that has improved fatigue life over existing lower-strength grades, while providing superior load-bearing capacity for use in live-well interventions and completions. This represents an increase of 20,000 psi in minimum yield strength over the previously highest available grade. The longest string of QT-1300 manufactured, to date, is more than 35,000 continuous ft in length.

To ensure functionality, QT-1300 has been tested for compatibility with typical CT equipment, such as injectors, connectors for downhole tools, and BOPs (BOP shear and slip testing). It has also been incorporated into third-party fatigue modeling, as well as proprietary service company models.

QT-1300 has been utilized successfully by development partners, both onshore and offshore, in HPHT wells, and for extended reach applications. Onshore successes have been seen in North American shale plays, such as the Bakken and Eagle Ford. Offshore, both in the North Sea and in the Gulf of Mexico, QT-1300 has enabled operators to perform operations that were not previously feasible. WO



15 key comparisons between Multistage Unlimited, plug & perf, and ball-sleeve/packer completions

Based on 4.5-in casing	**Multistage Unlimited**	**Plug & Perf** *(five clusters/stage)*	**Ball-Sleeves and Packers**
Unlimited stages?	Yes	Yes	No
Single-trip completion?	Yes	No	Yes
Less than 1 hour per stage?	Yes	No	Yes
Precise frac locations?	Yes	No	No
Required frac flowrates?	25–35 bpm	85–100 bpm	85–100 bpm
Number of frac units required?	3–5	12–14	12–14
Circulate fluids to frac zone?	Yes	No	No
Water and chemicals conservation?	Yes	No	No
Reduce the risk of screenouts?	Yes	No	No
Reverse out sand from screenouts?	Yes	No	No
Real-time frac zone pressure reading?	Yes	No	No
Unrestricted wellbore with no drillouts?	Yes	No	No
Eliminates rig-down/rig-up between stages?	Yes	No	Yes
Cemented wellbore isolation?	Yes	Yes	No
Coiled tubing required?	Yes	Yes	Yes

We rest our case.

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+1 281.453.2222
ncsfrac.com
info@ncsfrac.com

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MELANIE.CRUTHIRDS@WORLDOIL.COM



Shell announced that **Ben van Beurden**, the current director of its refining and marketing operations, will become its new chief executive next year, replacing retiring CEO **Peter Voser**. Van Beurden took over the running of Shell's refining and marketing business in January. Before that, he held senior roles in chemicals and manufacturing, and served as private assistant to the company's chairman between 2002 and 2004. Van Beurden will become CEO, effective Jan. 1.

Longtime chairman and CEO of Mobil, **Rawleigh Warner**, died June 26 in Hobe Sound, Fla., at the age of 92. Warner, chairman and CEO of Mobil from 1969 to 1986, and president from 1965 to 1969, was an early leader in the area of advocacy advertising, giving his company a voice in the public affairs space. He was born Feb. 13, 1921, in Chicago, and his father was chairman of Pure Oil. Warner graduated in 1943 from Princeton University, and then served in the U.S. Army in Italy during World War II. Warner spent much of his early career at Socony, the Standard Oil Co. of New York. He managed Socony's Middle East department, and was named a regional V.P. of Mobil International Oil, a Socony division. He became president of the renamed Socony Mobil Oil Co. in 1965. It became Mobil a year later. After retiring from Mobil, he served on corporate boards, including that of American Express. In addition to his wife, Warner's survivors include two daughters, two sisters, four grandchildren, and four great-grandsons.



George P. Mitchell, a billionaire philanthropist credited as the father of hydraulic shale fracturing, died at the age of 94 on July 26. His family said the death was from natural causes. A native of Galveston, Texas, he was the chairman and CEO of Mitchell Energy & Development, which was sold to Devon Energy for $3.5 billion in 2002. Mitchell drilled for natural gas in the Barnett shale, the site of the first successful fracing application that resulted in the viable production of natural gas. Since then, fracing has revolutionized the nation's domestic energy supply outlook. Mitchell, a veteran of World War II, was also a real estate developer. In 1974, he created The Woodlands, a 25,000-acre forested community filled with parks and a 1.4-mi-long manmade canal, north of Houston. The Woodlands now has a population of more than 100,000, and is home to leading oil and gas corporations including Anadarko Petroleum and ExxonMobil. Mitchell raised 10 children with his wife, Cynthia Woods Mitchell, who died in 2009.

Dana Gas has announced the appointment of **Dr. Patrick Allman-Ward** as the new group CEO for the company, effective Sept. 1. The company conducted an extensive executive search process after the retirement last year of its former CEO, **Ahmed Al-Arbeed**, who remains a board member. Allman-Ward is an international energy executive with more than 30 years of experience in the industry, in senior positions in the Middle East and the Gulf Region.



ABS has announced that **James A. Watson**, director of the Bureau of Safety and Environmental Enforcement (BSEE), will join ABS as president and COO of the Americas Division on Sept. 2. In this role, Watson will have operational responsibility for activity in North, South and Central America, and the Caribbean. Watson will take over from **Robert Gilman**, who will move to the ABS Group (ABSG) of companies as senior V.P. and head of Technical Inspection Services within ABSG Consulting.

Wood Group Mustang's Onshore Business Unit has appointed **Charles Johnson** to the position of general manager, Bakken region. Johnson will oversee the growing Wood Group Mustang presence in the region from the company's Minot, N.D., regional office. Johnson, a fifth-generation North Dakotan, brings 25 years of oil and gas experience to Wood Group Mustang, namely in tight formation plays in both the Bakken and Marcellus shales.

Pacific Drilling has appointed **Cees Van Diemen** as the company's COO, effective Aug. 1, with responsibility for operating and technical support activities. Van Diemen has more than 34 years of experience in the mobile offshore drilling industry, and joined Pacific Drilling in 2009 as senior V.P. of Operations. **Bob MacChesney** will assume the role of senior V.P. and chief marketing officer, focusing on the company's growing fleet of ultra-deepwater drillships.



Archer Limited's board of directors has appointed **David King** as CEO. King has more than 30 years of experience in international oilfield services, and replaces **Fredrik Halvorsen**, who has been Archer's interim CEO since January 2012. King has held numerous executive leadership roles, and worked most recently as president of Halliburton's Completion and Production Division. He left Halliburton in 2010, after 32 years with the company, to become an independent consultant.

Greene's Energy Group (GEG), a provider of integrated testing, rentals and specialty services, has promoted **Mark Yuille** to CFO of the Testing and Services business unit, announced President Eric Langlinais. Based in Houston, Yuille will assume financial leadership responsibilities that include accounting, treasury management and investor relations opportunities for the Testing and Services business unit of GEG. Prior to his new role, Yuille was CFO for GEG and, earlier, garnered notable financial and operational experience in various roles with GE.

FlexSteel Pipeline Technologies has appointed **Tom Ferguson** as CEO to lead the company's strategic growth in pipeline solutions for the oil and gas industry. Before joining FlexSteel, Ferguson spent the last 25 years at Flowserve, managing and building global, multi-billion-dollar businesses. He has a diverse background, crossing a multitude of functions, from marketing and sales to engineering and operations.



Superior Energy Services' president and CEO, **David D. Dunlap**, was honored as the 2013 Transformational CEO at the Ernst & Young Entrepreneur of the Year awards gala for the Gulf Coast Area. An independent panel of judges selected 41 finalists from the Gulf Coast area, representing South Texas, Louisiana and Mississippi, before choosing the final award winners.

UniversalPegasus International (UPI) has named **Tim Brown** as senior V.P., Business Development. Brown has more than 30 years of experience in the engineering and construction sectors. He comes to UPI from Jacobs Engineering, where he held the position of global V.P., Inside Sales and Marketing. Brown also worked for Fluor for more than 20 years, in various roles.

Scott Pellerin has been named operations manager of Pellerin Energy Group's (PEG) Water Solutions business unit. Pellerin's primary responsibilities include developing and implementing service programs, and training personnel on safe company product maintenance; negotiating service agreements; and ensuring equipment is operating efficiently. He will also manage the field service group, where he will oversee troubleshooting and customer training for produced water treatment equipment and solutions. Pellerin joins PEG as a former employee of Siemens, where he was employed for 13 years, and held various management positions.



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Newpark Drilling Fluids, a wholly-owned subsidiary of **Newpark Resources**, has opened its new world headquarters and laboratory facility in Katy, Texas. Newpark Drilling Fluids President Bruce Smith joined the company's executive staff in welcoming employees to their new home. The facility is on 11 acres along Houston's Interstate 10 Energy Corridor, just off Mason Road. Newpark's R&D laboratory, including a field services lab, occupies 37,000 sq ft of the building's combined 106,000 sq ft.

Independent E&P company **EPL Oil & Gas** has relocated its corporate headquarters from New Orleans, La., to 919 Milam St., Suite 1600, in Houston. With a focus on shallow-water Gulf of Mexico shelf E&P, EPL recently doubled its operations, in part by augmenting its geoscience and engineering teams in Houston, while keeping its accounting and production teams in New Orleans. To support the company's growth, a small number of employees relocated to Houston. EPL's revenue for first quarter 2013 was $182.3 million, compared to $98.8 million for the same period a year ago.

Specialty chemicals producer **Clariant** has opened a new R&D laboratory for catalysts for the chemical and oil and gas industries. Housed in the company's largest manufacturing plant in Latin America, in Suzano, Brazil, the laboratory begins operations with a complete infrastructure, state-of-the-art equipment and well-qualified team of researchers dedicated to developing new generations of catalysts. Fully operational in June, the new R&D laboratory was established from the acquisition of relevant catalyst assets from Brazilian company Oxiteno in mid-2012, which included patents and research labs.

Cluff Natural Resources was awarded a further, conditional, underground, coal gasification license; an option for a lease; and a non-exclusive exploration license for an underground coal gasification (UCG) prospect in the Firth of Forth, near Kincardine, Scotland. The award, given by the UK Department of Energy and Climate Change's Coal Authority, follows the award of two licenses in the Dee Estuary, on the border of Merseyside and North Wales, and Lougher Estuary, in Carmathenshire, Wales, in January 2013. The project consists of a 3,687-ha. license, in which Cluff has a 100% working interest.

Accelerated Companies, a subsidiary of **White Deer Energy**, has acquired **DynaFlo Artificial Lift Systems** and **Five Star Equipment**. DynaFlo and Five Star are Oklahoma-based providers of electric submersible pumps (ESP) and related services to the oil and gas industry. Founded in 2010, DynaFlo provides ESP products and services from its headquarters in Skiatook, Okla., and from four field locations in Oklahoma, Wyoming and Kansas. Five Star, which was founded in 2004, is based in Ramona, Okla. Five Star provides ESP products and services throughout the U.S. at the wholesale, retail and OEM levels.

Norwegian private equity fund **Herkules** has acquired Norwegian-headquartered oilfield technology specialist **Petroleum Technology Company** (PTC), which has an operating base in Aberdeen, Scotland. Herkules acquired a majority of the shares in PTC, and will partner to significantly grow the company, which specializes in gas lift and wellhead integrity for the global oil and gas industry. PTC is experiencing growth and, as part of the deal, almost $21 million will be injected as growth capital. Herkules is partnering with PTC's current owners, several of whom are key members of the management team.

2H Offshore, an **Acteon company**, has been awarded a contract by **Total** for the delivery management of the TLP top tensioned riser (TTR) systems for its Moho Nord field development, offshore Congo. Located about 75 km from Pointe-Noire, and 25 km west of N'Kossa, in water depths ranging from 450 m to 1,200 m, the Moho Nord project will target additional reserves in the southern part of the license, and new reserves in the northern part. 2H will be responsible for the riser delivery management, which includes design finalization, procurement management and inspection services for 17 production and water injection top-tensioned risers, and one high-pressure drilling riser.

Alcoa Oil & Gas, an Alcoa business, announced that it has executed a seven-year supply agreement with **ALTISS Technologies** for Alcoa's innovative AADP aluminum drill pipe. ALTISS will provide rental, inspection and maintenance services for AADP drill pipe in North America. ALTISS is a Houston-based company that provides products and services for the oil and gas industry. Financial terms of the transaction were not disclosed. This agreement significantly expands the availability of aluminum drill pipe within the growing North American market.

Plexus Holdings has been awarded its first contract with **Eni's** Australian subsidiary for the supply of POS GRIP wellhead technology with mud-line casing support and services, initially for one exploration well offshore Australia. The contract is worth more than $400,000, with revenues commencing in September, and includes an option for the continuing use of Plexus wellhead and mud-line equipment. This is anticipated to lead to a further three wells, with an additional estimated value of $1.52 million.

Schlumberger has officially opened the Schlumberger Reservoir Laboratory in Chengdu, China. The 32,000-sq-ft facility is the newest addition to the Schlumberger global network of reservoir laboratories. The laboratory offers an integrated suite of petrophysical and geomechanical services, to help customers improve hydrocarbon recovery and maximize production. The laboratory in Chengdu is designed to provide a complete suite of services, from field core acquisition to laboratory measurements. Laboratory personnel and petrotechnical experts work in close collaboration with domain experts, from initial data gathering through sample selection, rock testing, model calibration and further interpretation.

Louisiana Gulf Coast Oil Exposition (LAGCOE) will hold its inaugural LAGCOE Career Fair on Oct. 24, from 9 a.m. to 2 p.m., at the Cajundome & Convention Center, during the 2013 LAGCOE show. The group said that the creation of the LAGCOE Career Fair aligns with its mission of "fostering public education of the function and services of the oil industry" and "promotion of the oil industry as a whole." The event will be free to the public.

Vallourec inaugurated a new Research Center in Rio de Janeiro. Due to be operational by October 2013, the new center will focus on all pre-salt activities for the group, with the support of Vallourec's Research Center in Belo Horizonte, which was recently expanded as well, and other Vallourec research centers throughout the world. Vallourec has a worldwide network of more than 500 R&D engineers and technicians, and spent $119 million in 2012 on R&D.

Moncla Offshore Operations has transported its first platform workover rig, Moncla 301, to Cook Inlet in Alaska. The Moncla 301 was contracted by **Hilcorp Alaska**, a subsidiary of **Hilcorp Energy Company**, which is a privately-held E&P company based in Houston. The rig is one of two workover rigs being built by Louisiana manufacturer, **Superior Derrick Services**, at its facility in Parks, La., to be used in the Cook Inlet project. The rigs were specially designed to sustain the harsh weather conditions of Alaska's winter.

GE Oil & Gas will establish its new global headquarters in London. Florence will remain the global headquarters for GE Oil & Gas Turbomachinery Products & Services, a more-than-$6-billion business and a key manufacturing and engineering site for the production of centrifugal compressors and gas turbines. The new global headquarters will support the business and 43,000 employees working in more than 100 countries. The new headquarters will be operational in London, starting in January 2014.

MELANIE.CRUTHIRDS@WORLDOIL.COM

Line wiping tool introduced for field gauges



U.S. Tape has introduced a new line wiping tool, designed specifically for use in the oil field. The Line Wiper tool features a lightweight frame, with replaceable rubber cylinders to enhance performance and cost-effectiveness. The wiper has a built-in trigger action that controls braking as the gauging line is wiped. With use, the Line Wiper can save companies money by reducing rag usage, and protecting the costly gauging equipment found in many field operations. The tool can also help users reduce the effort required to constantly maintain gauging tools. As an HSEE benefit, the Liner Wiper also helps avoid hand cuts.

www.ustape.com

ONYX 360 rolling PDC cutter offers extended durability



Smith Bits, a Schlumberger company, has released the ONYX 360 rolling polycrystalline diamond compact (PDC) cutter. An industry first, this unique technology enables a PDC cutter to rotate 360° while drilling, significantly improving drill bit durability in abrasive formations, and extending drill bit life and footage drilled per run. Strategically positioned in the highest wear areas of a drill bit's cutting structure, the ONYX 360 rolling cutter uses its entire diamond edge to shear the formation as the bit rotates, thereby distributing wear over its full circumference. Comparatively, only a small fraction of the cutter edge is used in a conventional PDC bit. This rotation allows the cutter's diamond edge to stay sharp longer, increasing penetration rates and extending drill bit life compared to premium, fixed, PDC cutter technology. The new PDC cutter's 360° rotation also reduces frictional heat buildup, resulting in less wear and fewer bit replacement trips. In laboratory tests, the ONYX 360 rolling cutter was evaluated against a premium, fixed PDC cutter drilling a block of hard granite. After 90 passes on this test formation, the premium fixed cutter developed an extreme wear flat compared to the ONYX 360 rolling cutters, which showed virtually no sign of wear even after 540 passes.

www.slb.com/ONYX360

Ultra-fire-resistant cables designed for shipboard, offshore settings

Prysmian Group has introduced a new range of ultra-fire-resistant power, control and instrumentation cables for use in marine businesses. The product line, called Seaflame, was designed to withstand the specialized types of situations found in both shipboard and offshore applications. Developed by Prysmian's engineering and product development team, Seaflame combines technical features and design requirements to meet and exceed the most rigorous, stringent, fire resistance testing standards, including mechanical shock and water simulations. The applied testing protocol required that all tests be performed on the same, single cable lengths. The products withstood temperatures that reached 1,050° C, over a period of 180 to 360 min., with mechanical shock applied every five min., and additional water spraying and water jetting. Seaflame is fully industrialized and patented, and has already received approval by all major classification bodies, including Lloyd's Register, RIINA and others.

www.prysmiangroup.com

Suite of services monitors water in completions process

Select Energy Services has launched AquaView, a suite of services that efficiently monitors water at various stages of the completions process through real-time, wireless technology. AquaView's instant monitoring capabilities allow Select to respond immediately to on-site issues before emergencies arise. AquaView capabilities include pit and reservoir hydrographic surveys utilizing SONAR remote control and GPS real-time data; data delivered to a secure portal offering current and historical data; real-time water quality reporting; and mapping and Geographic Information Systems (GIS) support.

www.selectenergyservices.com

Web tool tracks hurricane path over energy infrastructure

U.S. Energy Information Administration (EIA) is introducing interactive maps that combine real-time data feeds from the National Hurricane Center, with more than 20 map layers showing the nation's energy infrastructure and resources. This new tool, available on the EIA website, allows users to better see, and understand, the potential impact of a storm. Every year, hurricanes affect the nation's energy infrastructure, especially when storm paths traverse offshore production rigs and pipelines in the Gulf of Mexico, coastal refineries, power plants, and critical energy import and export sites.

www.eia.gov/special/disruptions/

Drilling fluid system optimizes circulating pressure

Baker Hughes has recently introduced a drilling fluid system that aims to improve drilling economics by enabling operators to manage circulating pressure more efficiently. The MPRESS drilling fluid system allows operators to reduce their stand pipe pressure, and apply more horsepower to the BHA and drill bit, increasing rates of penetration and decreasing non-productive time. Baker Hughes recently commercialized the MPRESS system to reduce viscosity in the drillstring, while optimizing viscosity in the annulus, for more efficient cuttings transport. The pressure saved in the drillstring can be used to increase flowrate, provide more power to motors and bits, and save wear and tear on surface equipment. Combined with other Baker Hughes technologies, such as the Autotrak Curve rotary steerable system and Talon high-efficiency PDC bits, the MPRESS system enables highly efficient drilling of challenging lateral sections found in unconventional reservoirs.

www.bakerhughes.com

LWD service is less sensitive to noise, improves measurement accuracy

Sperry Drilling, a Halliburton business line, has the introduced the XBAT Azimuthal Sonic and Ultrasonic logging-while-drilling service. The XBAT LWD service delivers accurate acoustic measurements in a wide range of formations via sensors and electronics that are much less sensitive to drilling noise, and have a wider frequency response. The result is a greater signal-to-noise ratio that enables better measurements, even in noisy drilling environments and poor hole conditions. With more than 100 successful runs, the XBAT LWD service has delivered accurate measurements in formations from Brunei to Brazil, and has been tested extensively in the challenging environments of the North Sea and the Gulf of Mexico.

www.halliburton.com/XBAT

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WorldOil.com

NORTH AMERICA

TX
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Phone: +1 (617) 357-8190, Fax: +1 (617) 357-8194
Merrie.Lynch@GulfPub.com

OUTSIDE NORTH AMERICA

AUSTRALIA
Brian Arnold
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Australia@GulfPub.com

BRAZIL
Alfred Bilyk
Brazmedia
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JAPAN
Yoshinori Ikeda
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INDIA
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INDONESIA, MALAYSIA, SINGAPORE, THAILAND
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ITALY, EASTERN EUROPE
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KOREA
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RUSSIA, FSU
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P: +1 (514) 939-2710
cmurphy@cim.org
www.isarc2013.org

Modular Fabrication Technology and Management 2013, Aug. 11–13, Qingdao, China,
P: +86-10-62730706
events@bmc-china.cn
www.bmc-events.net/en/me-1357722200024.aspx

SPE, Unconventional Resources Technology Conference, **Aug. 12–14,** Colorado Convention Center, Denver, Colo.
(See box for contact information)

Summer NAPE, **Aug. 14–16,** George R. Brown Convention Center, Houston, Texas
P: +1 (817) 847-7700
F: +1 (817) 847-7704
info@napeexpo.com
www.napeexpo.com

Gulf Publishing Company Events, Shale Energy Technology Conference, **Aug. 28–30,** Norris Conference Centers—City Centre, Houston, Texas
(See box for contact information)

SEPTEMBER

SPE, Offshore Europe Oil and Gas Conference and Exhibition, **Sept. 3–6,** Aberdeen Exhibition and Conference Centre, Aberdeen, Scotland, UK
(See box for contact information)

dmg Events, East Africa Gas Forum, **Sept. 4–6,** Dar es Salaam, Tanzania
P: +1 (403) 444-6524
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customerservice@dmgevents.com
www.eastafricagasforum.com

AAPG, International Conference and Exhibition, **Sept. 8–11,** Cartagena Convention Center, Cartagena, Colombia
P: +1 (918) 560-2679
F: +1 (918) 560-2684
convene@aapg.org
www.AAOG.org/cartagena2013

IADC, Celle Drilling 2013 **Sept. 9-10,** Congress Union, Celle, Germany
(See box for contact information)

Oil Sands Trade Show and Conference, **Sept. 10–12,** Suncor Community Leisure Center, Ft. McMurray, Alberta, Canada
P: +1 (888) 799-2545
F: +1 (403) 245-8649
customerservice@dmg.com
www.oilsandstradeshow.com/2013

SPE, 2013 Liquids Rich Basins Conference, **Sept. 11–12,** Midland Convention Center, Midland, Texas
(See box for contact information)

IADC, Advanced Rig Technology Conference & Exhibition **Sept. 17-18,** Radisson Blu Atlantic Hotel, Stavanger, Norway
(See box for contact information)

Heavy Oil Latin America, **Sept. 24–26,** International Convention Center, Puerto Vallarta, Mexico
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www.heavyoillatinamerica.com/2013

Gulf Publishing Company Events, High Pressure High Temperature Drilling and Completions Conference, **Sept. 26–27,** Norris Conference Centers—City Centre, Houston, Texas
(See box for contact information)

SPE, Annual Technical Conference and Exhibition (ATCE), **Sept. 30–Oct. 2,** Ernest N. Morial Convention Center, New Orleans, La.
(See box for contact information)

Texas A&M University System, Turbomachinery Laboratory, Pump/Turbomachinery Symposia, **Sept. 30–Oct. 3,** George R. Brown Convention Center, Houston, Texas
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www.turbolab.tamu.edu

OCTOBER

21st Kazakhstan International Oil & Gas (KIOGE) Exhibition, Oct. 1–4, Atakent Exhibition Centre, Almaty, Kazakhstan
www.kioge.com/about-exhibition.html

Global Energy Career Expo, **Oct. 1–2,** Metro Toronto Convention Centre, Toronto, Canada
P: +1 (403) 444-6524
F: +1 (403) 245-8649
www.globalenergycareerexpo.com/toronto/2013.

SPE/IADC Middle East Drilling Technology Conference & Exhibition, **Oct. 7–9,** Madinat Jumeirah, Dubai, United Arab Emirates
(See box for contact information)

Chad International Oil, Mining and Energy Conference and Exhibition, Oct. 8–11, N'Djamena, Chad
P: + 44 (0) 208 605 0509
www.ciome-chad.com/

China Offshore Engineering Symposium 2013, **Oct. 10–11,** Beijing, China
P: +86-10-62730706
www.bmc-events.net/en/me-1358141322078.aspx

China Natural Gas Summit 2013 Oct. 12, Beijing, China,
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www.bmc-events.net/en/me-1359360232049.aspx

Marine Technology Society (MTS), Dynamic Positioning Conference, **Oct. 15–16,** Westin Memorial City Hilton, Houston, Texas
www.dynamic-positioning.com

SPE, Arctic and Extreme Environments Technical Conference and Exhibition, **Oct. 15–17,** All Russia Exhibition Center, Moscow, Russia
(See box for contact information)

American Association of Petroleum Geologists (AAPG), 3P Arctic 2011, Polar Petroleum Potential Conference & Exhibition, **Oct. 15–18,** Stavanger Forum, Stavanger, Norway
P: +44 207 434 13 99
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apatel@aapg.org
www.3parctic.com/2013

IADC, Critical Issues for Unconventionals Europe 2013 Conference & Exhibition, **Oct. 23-24,** Hilton Warsaw Hotel & Convention Centre, Warsaw, Poland
(See box for contact information)

Gulf Publishing Company Events, Women's Global Leadership Conference, **Oct. 29–30,** Hyatt Regency Houston, Houston, Texas
(See box for contact information)

OTC Brasil, **Oct. 29–31,** Riocentro Convention Center, Rio de Janeiro, Brazil
otcbrasil@ibp.org.br
www.otcbrasil.org/2013

NOVEMBER

Interstate Oil & Gas Compact Commission, Annual Meeting **Nov. 4–6,** Renaissance Long Beach Hotel, Long Beach, California
P: +1 (405) 525-3556
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iogcc@iogcc.state.ok.us

IADC, Annual General Meeting, **Nov. 6–8,** Westin La Cantera, San Antonio, Texas
(See box for contact information)

Independent Petroleum Association of America (IPAA), Annual Meeting, **Nov. 7–9,** Hyatt Regency Hotel, San Antonio, Texas
P: +1 (202) 857-4722
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The Lebanon International Oil and Gas Summit 2013 (LIOG), **Dec. 4–5,** Lebanon Phoenecia Hotel, Beirut, Lebanon
P: +44 20 3488 1193
adagher@gep-events.com
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KURT ABRAHAM, EXECUTIVE EDITOR

A return of the Cold War will affect oil and gas



Recent events suggest that an old-style Cold War is slowly returning, as regards Russia vs. the U.S. And if this is true, there may be repercussions for upstream oil and gas.

Over the last six months, various incidents point toward deterioration in Russia's relationship with the U.S. and its allies. Simultaneously, one can see a continuing consolidation of Russia's oil and gas industry, with a growing level of control returning to the central government, under President Vladimir Putin, as described by our FSU contributor, Dr. Jacques Sapir, in his column on page 23 of this issue of *World Oil*. The two situations are interwoven, as only the Kremlin can do it.

First, as regards Russian-U.S. relations, consider these incidents in recent months:

- Feb. 7—Two Russian SU-27 fighter jets invade Japan's airspace near two disputed islands, and the Japanese island of Hokkaido.
- Feb. 12—Two Russian TU-95 "Bear" bombers circle the U.S. territory of Guam, hours before President Obama's State of the Union address.
- May 7—U.S. Secretary of State John Kerry endures a chilly reception while visiting in Moscow with Putin and Foreign Minister Sergey Lavrov.
- June 11—Two Russian military aircraft cross into Finland's airspace, forcing the Finnish Air Force to dispatch fighter jets to intercept them.
- June 17—Obama has a tense, chilly bi-lateral meeting with Putin during the G8 summit in Northern Ireland.
- July 15—Two Russian TU-95 "Bear" bombers fly practice missions near the Korean Peninsula and Japan's Hokkaido Island. Three Japanese fighters intercept the bombers.
- July 19—Obama is considering whether to cancel a fall summit scheduled with Putin in Moscow, partially because Russia harbors American intelligence fugitive Edward Snowden, who was recently granted temporary asylum and has left the airport.
- July 24—Snowden's lawyer tells journalists that the fugitive will remain in Russia long-term until his temporary asylum request is made permanent.

For the U.S. administration, that is a depressing list. The February, June and July military incidents look like something right out of the Cold War days of the late 1950s through 1970s. In a fashion that would make late Soviet leader Nikita Khrushchev proud, Putin seems to be figuratively thumbing his nose at Obama.

The May, June and July diplomatic incidents are equally disturbing. Kerry was kept waiting three hours for his visit with Putin. When he finally showed, Putin had plenty that he was upset with the U.S. about—Kerry's assertion that Russia should quit supporting Syrian dictator Bashir Assad; negative U.S. reaction to a new Russian law banning American adoptions of Russian orphans; and Putin's contention that the U.S. intervenes in Russian internal affairs by supporting so-called democratic opposition to his regime; among other issues.

A month later, Obama's June 17 meeting with Putin during the G8 Summit in Northern Ireland proved equally unproductive. Putin insisted on continuing his support for Syria's Assad, while the Obama administration subsequently committed to sending arms to Syrian rebel forces. In Cold War fashion, Putin and Obama chose opposing sides, and one has to wonder if this pattern will now repeat itself in other parts of the globe. In addition, Obama's call for the two countries to jointly reduce nuclear weapons stockpiles, which was meant to be an olive branch to the Russians, was interpreted by the Kremlin as a U.S. move to undermine Russia's nuclear deterrent capability.

We are seeing real consequences stemming from the two presidents' radically different styles. Obama is a professorial dreamer, while Putin is a ruthless pragmatist. While Obama peddles utopian dreams of boundless green energy, Putin pursues a calculated strategy of oil and gas development. As Dr. Sapir describes in his column, it is no accident that Putin has put Igor Sechin in control of Rosneft, and, by default, in charge of all Russian oil and gas policy. Sechin, like Putin, is a ruthless pragmatist, referred to by Russian citizens as "Darth Vader." As Dr. Sapir points out, we have already seen how Sechin is beginning to marginalize Gazprom, so what will become of Lukoil and Surgutneftegas? Will Putin and Sechin restore complete governmental control over all Russian oil and gas assets?

In addition, as the U.S., thanks to shale development, ramps up its own oil production and becomes more self-sufficient, imports from abroad are being displaced, and a global oil glut could form eventually, lowering prices substantially. Given that close to 80% of Russia's hard currency earnings still come from oil and gas, Putin and Sechin will not tolerate a low-price environment. Nor, will they tolerate extensive diversification of Western European gas supplies, away from Russian sources. Accordingly, some analysts speculate that the Russians have worked behind the scenes to stir up environmental activists and encourage protests against hydraulic fracturing.

We are just beginning to see events unfold in Russia—they warrant further, close attention in the coming months.

A note of thanks. Before we close out and go on to the September issue, I want to express my sincere thanks and appreciation to our colleagues in the various U.S. state agencies regulating oil and gas, as well as the folks at the federal agency, BSEE. Without the able assistance and data provided by these dedicated professionals, it would be nearly impossible to assemble the mid-year forecast update contained in this issue of *World Oil*, as well as its cousin, the beginning-of-year forecast in our February issues. These folks are doing their jobs well, despite frequent shortages of personnel and resources. WO

KURT.ABRAHAM@WORLDOIL.COM

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