

JPT

Dual-Gradient Drilling Moves Offshore

RESERVOIR SIMULATION

ARTIFICIAL LIFT

UNCONVENTIONAL RESOURCES

CO₂ APPLICATIONS

FEATURES

Improving BOP Downtime

**Beyond the Headlines:
Explaining the Industry
to the Public**

Qatar's R&D Push



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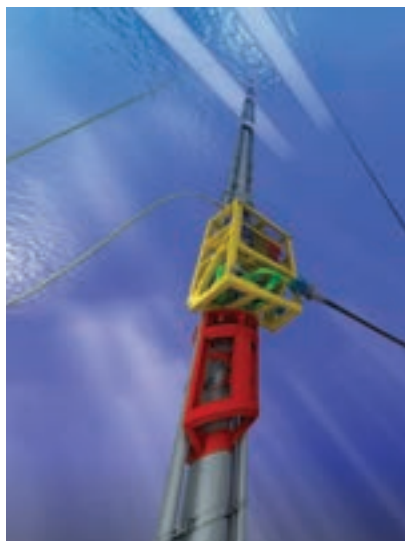
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Volume 66 • Number 7



Cover: Inside the yellow frame is a pumping system attached to a drilling riser about 1,000 ft below the surface. Drilling fluid flows out of a modified riser joint into the disc pump in the EC-Drill unit and into the black, flexible tubing running to a drilling rig. *Image courtesy of Enhanced Drilling.*

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20 BEYOND THE HEADLINES: HOW THIRSTY IS SHALE GAS?

A newspaper recently reported about a California county's ban of hydraulic fracturing because of concerns regarding freshwater consumption in a drought year. Shale oil or gas production does use a lot of water, but not as much as other sources of energy.

40 EXTREME DEEPWATER WELLS PUSH DRILLERS TO BEGIN USING MANAGED-PRESSURE METHOD

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68 UNCONVENTIONALS, TECHNICAL CHALLENGES HIGHLIGHT OTC

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86 TALENT & TECHNOLOGY • A NEW CONTRACT BETWEEN MANAGEMENT AND PETROTECHNICAL PROFESSIONALS

The continued search for oil and gas relies in equal measure on good management and superior petrotechnical expertise. The key is ensuring that the two worlds mesh smoothly.

148 TOPICS FOR 2014-15 DISTINGUISHED LECTURER SEASON

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APPLICATIONS

- SHALE OIL
- SHALE GAS DELIQUIFICATION
- CONVENTIONAL OIL
- GAS WELL DEWATERING
- HIGH-SOLIDS PRODUCTION
- HEAVY OIL
- SAGD
- HORIZONTAL WELLS

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TECHNOLOGY FOCUS

ONYX 360
ROLLING PDC CUTTER

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ONYX 360 PDC cutter wear (left) compared with the wear of a conventional fixed cutter (right).

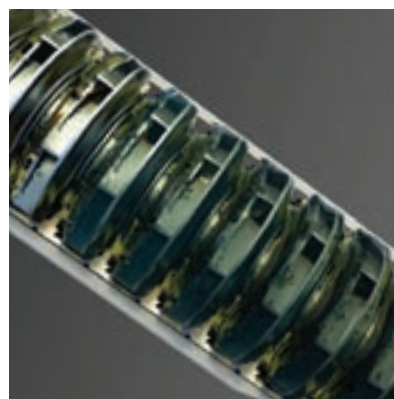
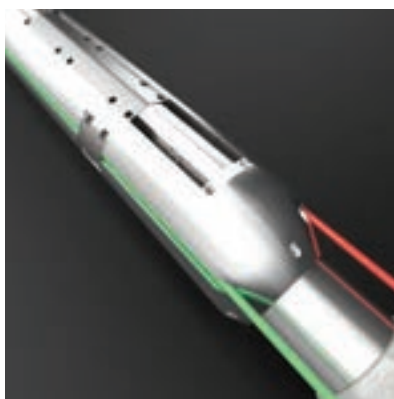
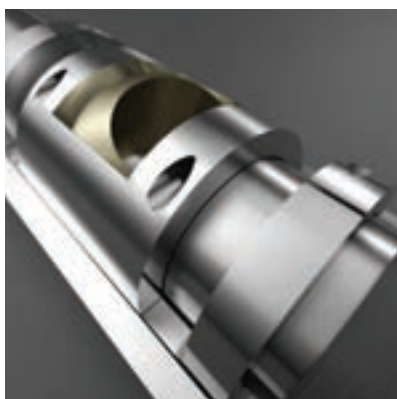
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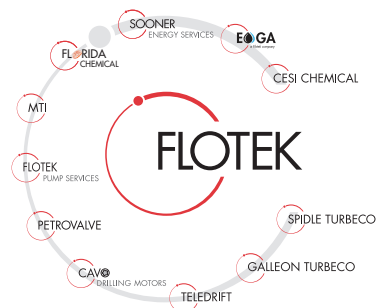
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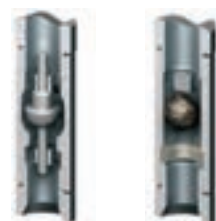
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PERFORMANCE INDICES

WORLD CRUDE OIL PRODUCTION[†]

THOUSAND BOPD

OPEC	2013 JUL	AUG	SEP	OCT	NOV	DEC
Algeria	1520	1520	1412	1412	1420	1520
Angola	1750	1730	1770	1760	1750	1750
Ecuador	530	537	535	539	544	548
Iran	3200	3200	3200	3200	3200	3200
Iraq	3100	3275	2825	2975	2975	2925
Kuwait*	2650	2650	2650	2650	2650	2650
Libya	1000	590	360	550	220	230
Nigeria	2400	2370	2420	2370	2270	2350
Qatar	1553	1553	1553	1553	1553	1553
Saudi Arabia*	10040	10240	10140	9840	9840	9740
UAE	2820	2820	2820	2820	2820	2820
Venezuela	2300	2300	2300	2300	2300	2300
TOTAL	32863	32785	31985	31969	31542	31586

THOUSAND BOPD

NON-OPEC	2013 JUL	AUG	SEP	OCT	NOV	DEC
Argentina	545	542	546	547	543	540
Australia	363	357	353	284	337	338
Azerbaijan	890	800	870	855	870	880
Brazil	1974	2011	2094	2079	2081	2109
Canada	3306	3471	3352	3335	3468	3822
China	4043	4075	4107	4255	4205	4215
Colombia	1020	1031	995	986	998	989
Denmark	177	162	157	172	168	160
Egypt	538	536	534	533	530	530
Eq. Guinea	270	285	293	293	293	293
Gabon	245	246	247	249	250	250
India	766	766	767	766	781	784
Indonesia	811	808	795	799	793	785
Kazakhstan	1586	1466	1530	1633	1634	1637
Malaysia	509	508	491	480	526	504
Mexico	2522	2554	2563	2580	2553	2557
Norway	1648	1546	1395	1477	1613	1611
Oman	931	947	958	953	950	945
Russia	10052	10064	10082	10109	9837	10118
Sudan	301	277	317	342	367	340
Syria	63	53	48	37	31	25
UK	791	628	742	731	833	956
USA	7467	7501	7788	7710	7941	7864
Vietnam	325	322	322	328	329	326
Yemen	133	128	110	131	130	112
Other	2417	2428	2358	2374	2415	2429
Total	43693	43513	43813	44037	44476	45119
Total World	76556	76298	75798	76006	76018	76705

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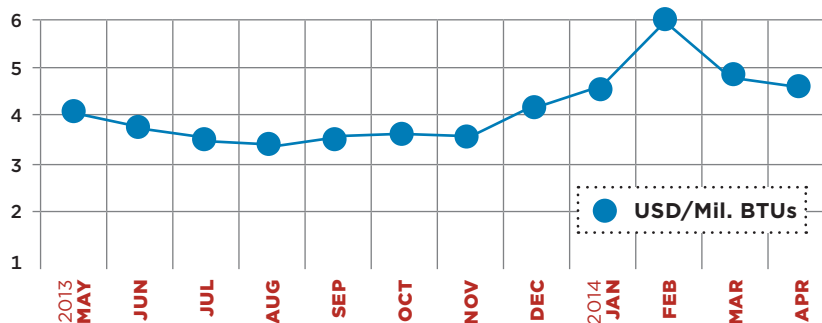


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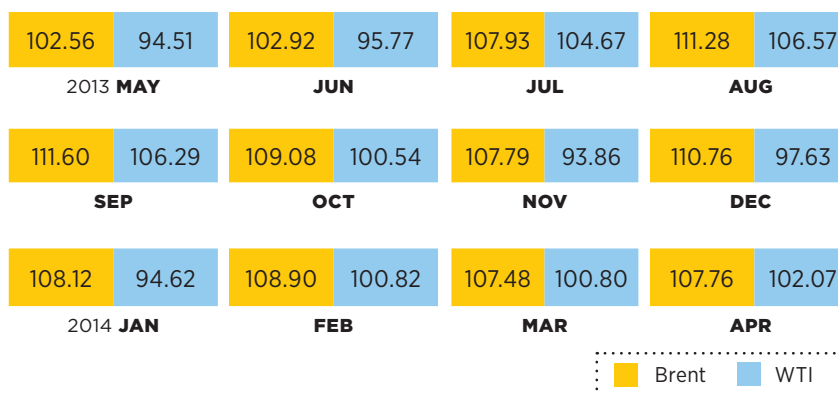


PERFORMANCE INDICES

HENRY HUB GULF COAST NATURAL GAS SPOT PRICE*†



WORLD CRUDE OIL PRICES (USD/bbl)‡



WORLD ROTARY RIG COUNT†

REGION	2013 NOV	DEC	2014 JAN	FEB	MAR	APR	MAY
US	1756	1771	1769	1769	1803	1835	1859
Canada	385	372	504	626	449	204	162
Latin America	411	417	401	400	406	403	404
Europe	137	126	126	132	148	151	149
Middle East	388	405	403	396	401	407	414
Africa	135	138	139	154	132	136	140
Asia Pacific	240	249	256	259	258	252	243
TOTAL	3452	3478	3598	3736	3597	3388	3371

WORLD OIL SUPPLY AND DEMAND^{1‡}

MILLION BOPD	2013			2014
Quarter	2nd	3rd	4th	1st
SUPPLY	90.43	90.95	90.87	90.61
DEMAND	89.89	91.05	91.29	90.73

INDICES KEY

* Figures do not include NGLs and oil from nonconventional sources.

† Includes approximately one-half of Neutral Zone production.

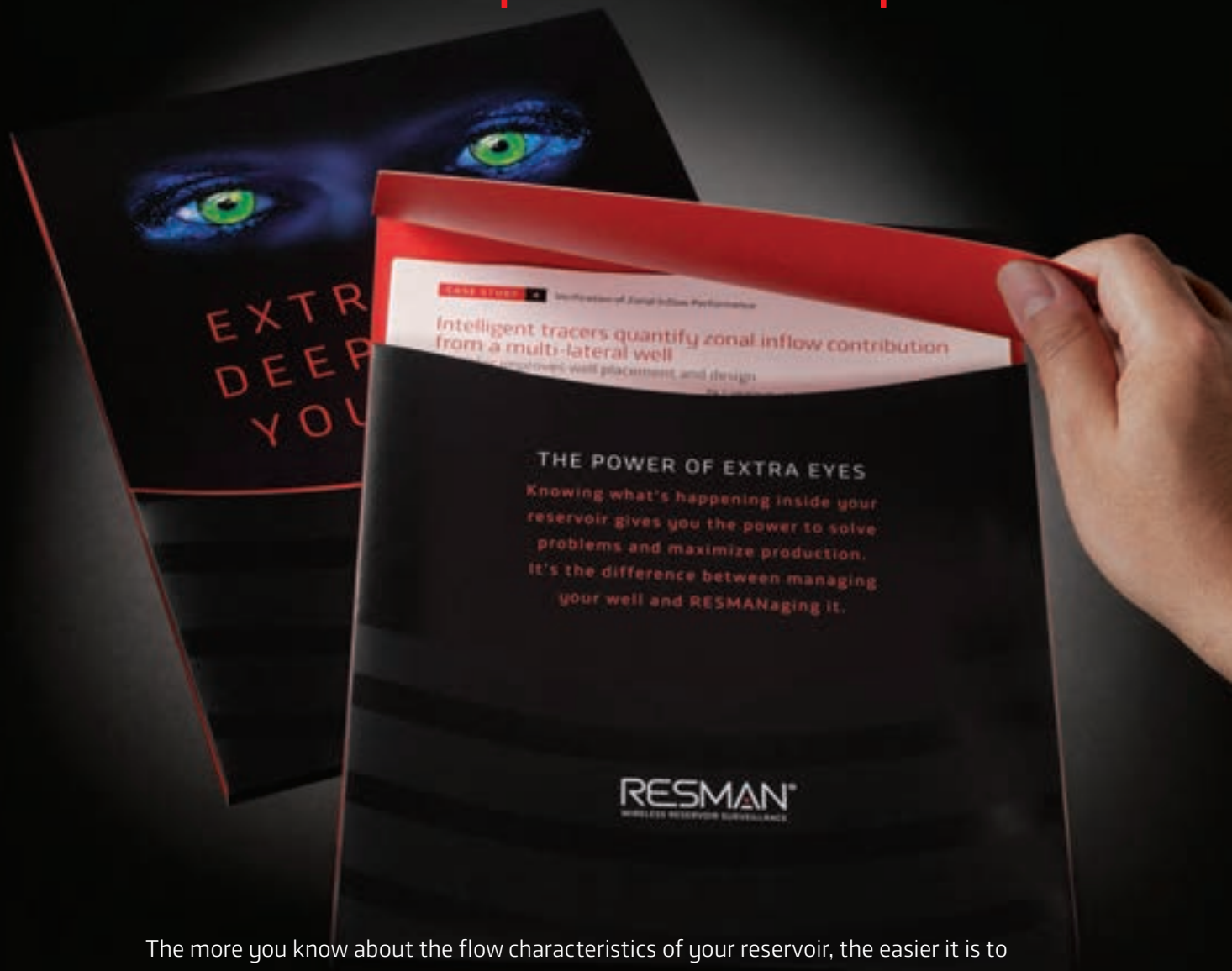
‡ Includes crude oil, lease condensates, natural gas plant liquids, other hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from nonconventional sources.

† Source: Baker Hughes.

* The US Dept. of Energy/Energy Information Administration discontinued its reporting of US Natural Gas Wellhead Prices, replacing them with Henry Hub Gulf Coast Natural Gas Spot Prices.

‡ Source: US Dept. of Energy/Energy Information Admin.

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REGIONAL UPDATE

AFRICA

► **Sonangol's** deepwater Orca-1 well encountered oil in the presalt layer of Block 20/11 in the Cuanza basin offshore Angola. The well reached a measured depth of 12,703 ft. Initial well tests saw flow rates of 16.3 MMcm/D of gas and 3,700 BOPD. **Cobalt International Energy** (40%) is the operator, with partners **Sonangol Research and Production** (30%) and **BP Exploration Angola** (30%).

ASIA

► **Premier Oil's** Kuda Laut-1 well in Indonesia's Tuna production sharing contract has encountered 183 net ft of oil-bearing reservoir and 327 net ft of gas-bearing reservoir. Following evaluation operations, the well will be sidetracked to drill the Singa Laut prospect in an adjacent fault block. Premier is the operator (65%), with partner **Mitsui Oil Exploration Company** (35%).

► **Philippines National Oil Company (PNOC)** has begun drilling operations on its Baragatan-1 exploration well on service contract 63, offshore Palawan Island, west of the Philippines, using the *Naga 5* jackup rig. PNOC (40%) is the operator, with partners **Dragon Oil** (40%) and **Nido Petroleum** (20%).

AUSTRALIA

► **Statoil Australia Theta** started drilling operations at the OzBeta-1 vertical exploration well, located in EP 127, south Georgina basin, Northern Territory, Australia. The well will be drilled to an approximate depth of 1300 m. The well will test three potential pay zones within the structures and formations in that area, particularly targeting a 40- to 50-m section expected within the Thorntonian Limestone formation. Statoil (60%) is the operator, with partners **Baraka Energy & Resources** (25%) and **PetroFrontier** (15%).

EUROPE

► **Hurricane Energy** has spudded an appraisal well on the Lancaster discovery at P1368, in the North Sea, west of the Shetland Islands, at a 160-m water depth. According to a report prepared by RPS Consultants in November 2013, 2C

recoverable contingent resources allocated to Lancaster were 207 million BOE. The well is being drilled by semisubmersible *Sedco 712*. Hurricane (100%) is operator of the license.

► **Statoil** well 7220/7-3 S encountered hydrocarbons in the Drivis PL 532, Barents Sea. The vertical well intersected a 68-m gross gas column in the Stø formation and an 86-m gross oil column in the Stø and Nordmela formations. The well was drilled to a vertical depth of 2029 m below the sea surface and was terminated in the late Triassic Fruholmen formation. Water depth at the site is 345 m. Statoil estimates the total recoverable volumes in the Drivis prospect to be in the range of 44 to 63 million BOE (90% oil). Statoil (50%) is the operator, with partners **Eni Norge** (30%) and **Petoro** (20%).

► **Statoil's** 16/2-19 appraisal well, located on the PL265 Johan Sverdrup discovery in the North Sea's Norwegian continental shelf, has encountered oil. The well found 6 m of oil-bearing sandstone of Lower Jurassic/Upper Triassic age in the Geitungen area in the northeastern part of the Johan Sverdrup discovery. Sidetrack well 16/2-19A encountered 13 gross m of low- to excellent-quality upper Jurassic sandstone. Statoil (40%) is operator, with **Petoro** (30%), **Det Norske** (20%), and **Lundin** (10%).

► **Chevron** has spudded its first exploratory shale well in Romania. The well's commencement has been repeatedly delayed by anti-fracturing protesters; it was originally set to be spudded at the end of 2013. The vertical well will be drilled to 13,000 ft, and will take approximately 90 days to reach total depth.

MIDDLE EAST

► **Oil Search** has discovered hydrocarbons at 3255 m in its Taza-2 well in Kurdistan. These hydrocarbon shows were encountered in the Jeribe formation, where an 18-m core was cut from the carbonate reservoir. Taza-2 is located 10 km northwest of Taza-1 and is designed to appraise the hydrocarbon-bearing intervals discovered by Taza-1. The well is also targeting Tertiary and Cretaceous layers, including the Shiranish formation. Oil Search (60%) is the operator, with partners **Total** (20%) and the **Kurdistan Regional Government** (20%).

► **Khalda Petroleum Company**, an Apache-operated joint venture with the **Egyptian General Petroleum Company**, made two natural gas and condensate discoveries in Egypt. The Herunefer-1X discovery, located in the Matruh basin, encountered pay in the Alamein, Alam El Buieb-6 (AEB), Masajid, Upper Safa, and Lower Safa formations. Tests from the Lower Safa and Upper Safa intervals flowed at a combined rate of 49 MMcf/D of gas and 7,700 B/D of condensate. The BAT-1X discovery, located in the northern Shushan basin, tested at 31 MMcf/D of gas and 390 B/D of condensate from a thick Paleozoic Shiffah sandstone interval. The 15,555-ft well also encountered pay in the Cretaceous Upper Bahariya, Lower Bahariya, Alamein, AEB-3C, and AEB-3D formations. Khalda (100%) is operator of the lease.

NORTH AMERICA

► **Leni Gas & Oil's** onshore Trinidad development well, GY-664, encountered approximately 193 ft of gross oil-bearing sands in the Upper Goudron sands. Drilling continues in the remaining Goudron sands, estimated to be 400 ft thick, to the first casing point at approximately 1,540 ft, where electric logs will be run. Drilling will then continue in order to test the primary objectives in the Gros Morne and the Lower Cruse sands at depths below 2,800 ft. Leni (100%) is the operator.

► **Stone Energy** encountered more than 275 ft of net oil pay in three separate sections of the deepwater Cardona South well (MC 29 #5) in Mississippi Canyon 29, Gulf of Mexico. Water depth is 2,135 ft. **Stone** (65%) is operator, with partner **Hunt Oil** (35%).

SOUTH AMERICA

► **Canacol Energy** encountered light oil in the Pantoro-1 exploration well in the LLA23 exploration and production contract in the Llanos basin, Colombia. The well was drilled to a total depth of 12,682 ft and encountered 83 ft of net oil pay in five separate reservoirs. The 37 ft of net pay within the Gacheta reservoir flowed at a net rate of 2,300 B/D of 31° API crude over a 24-hour period. Canacol (80%) is the operator, with partner **Petromont** (20%). **JPT**

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MERGERS AND ACQUISITIONS

► **EQT Midstream Partners** agreed to acquire **EQT Corporation's** Jupiter natural gas gathering system for USD 1.18 billion. EQT will receive USD 1.12 billion in cash and USD 59 million in common and general partner units. EQT Midstream Partners will fund USD 182 million worth of expansion projects related to Jupiter. The Jupiter system's total pipeline capacity is 970 MMcf/D. The system is approximately 35 miles in length and gathers EQT's Marcellus production in portions of Greene and Washington counties in Pennsylvania.

► **Calmena Energy Services** has sold its Canada-based **Drilling Technologies** research and manufacturing division and certain related assets to **FastCAP Systems Corporation**. The consideration consists of USD 1 million in cash and the provision of USD 1.2 million in the form of services and technology products provided to Calmena by FastCAP over the next 4 years.

► **SM Energy** entered into separate agreements to acquire approximately 28,000 additional net acres in the Powder River basin in northeast Wyoming. The company has agreed to pay a cash consideration of approximately USD 100 million, plus trade approximately 7,000 net acres in other portions of the basin. The acquisition will increase SM Energy's total acreage in the Powder River basin to approximately 161,000 net acres.

► **Petronas** entered into an agreement with Sinopec and **China Huadian Corporation** to sell a 15% interest in the Pacific Northwest Liquefied Natural Gas (LNG) Project in Canada. Sinopec will acquire 10% interest in the project, while China Huadian will acquire 5% interest in the project. The agreement also includes a commitment from Sinopec to offtake 1.2 million tonnes per annum of LNG for a minimum period of 20 years, while China Huadian will offtake 600 000 tonnes per annum. Located on Lelu Island, within the District of Port Edward, on land administered by the Port of Prince Rupert, British Columbia, the pipeline has a capacity of 12 million tonnes per annum.

► **Aker Solutions** has announced that it will split into two entities. One will

focus on Aker's subsea and deepwater operations; the other will consist of Aker's drilling technologies and oilfield service units. The split is scheduled to occur around the end of September 2014. Both companies will be listed on the Oslo Stock Exchange.

► **OMV** has agreed to take a stake in two blocks offshore Madagascar, leased by Tullow Oil. Under the deal, OMV will take a 35% stake in Block 3109 (Mandabe) and Block 3111 (Berenty), while Tullow will remain operator of both with a 65% stake. The deal is subject to the approval of Madagascar's government.

COMPANY MOVES

► **Langan Engineering & Environmental Services** announced the opening of an office in Akron, Ohio. The new office will provide fully integrated technical services in support of activity in the Utica shale, as well as for land development projects and corporate real estate portfolios throughout the state.

► **GE** broke ground on its new, 100,000-ft² research facility in Oklahoma City. The site will be devoted to studies on production, water use, well construction, and CO₂ applications and represents a USD-125-million investment. When the facility opens in 2015, it will create 130 jobs.

► Energy standards resource center **Energistics** is in the process of moving its Houston office to a larger location with a larger conference room and video conference capabilities for international members. The organization will host an open house for members in August.

CONTRACTS

► **BP Exploration & Production** has awarded **Subsea 7** a 3-year, USD-160-million contract for light subsea construction, inspection, repair, and maintenance services in the US Gulf of Mexico. The contract will run from the second quarter 2014 to the third quarter 2017. Contract scope covers the provision of two vessels, including a dedicated vessel on a full-time basis; associated project management and engineering support; remotely operated vehicle-based

inspection and intervention; and light construction work.

► **BHP Billiton Petroleum** chartered the semisubmersible, *Atwood Falcon*, from **Atwood Oceanics** for operations in Australia. The contract has a term of 330 days at a day rate of approximately USD 430,000. As part of this contract, BHP retains the right to further extend the contract for two option periods of approximately 120 days each, at the same day rate.

► A consortium of **BOS Shelf**, **Saipem**, and **Star Gulf FZCO** has secured a USD-1.8-billion offshore transport and construction contract to help develop the Shah Deniz II gas project in Azerbaijan. The contract is for the offshore transport and installation of jackets and topside units, subsea production systems, and subsea structures that will be used in the Caspian Sea. It also includes diving support services, the upgrade of three installation vessels, and the laying of over 360 km of subsea pipelines, with all work expected to be completed by the end of 2017.

► **Saipem** has been contracted by **South Stream Transport** to provide support work for construction of the second line of the South Stream Offshore Pipeline. The contract is worth USD 554 million. Saipem will also perform further support work, including engineering, coordination of storage yards, cable-crossing preparation, and connection of the offshore pipeline to the landfall sections through tie-ins. The construction related to the second line is expected to be completed by the end of 2016. The offshore section of the South Stream gas pipeline will consist of four parallel lines—each longer than 930 km—across the Black Sea from the Russian coast to the port of Varna in Bulgaria.

► **Prysmian Group** has been awarded a USD-41.7-million submarine cable contract for the Zakum oil field offshore Abu Dhabi. Work includes design and manufacture of submarine cable links for the replacement of power feeding systems to the Zakum field. The Zakum oil field is the first submarine electrification project planned by **Abu Dhabi Marine Operating Company. JPT**

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Collaboration

Jeff Spath, 2014 SPE President



One of the personal objectives I took as president was to increase the extent in which SPE collaborates with other professional societies and other industries. This is important for two reasons. First, I think we all will agree that meeting the world's increasing energy demand is becoming more challenging. Reservoirs are becoming more difficult to find and produce. They are generally smaller, more complex, and exist in increasingly challenging environments, whether in the Arctic,

beneath 10,000 ft of water, or at very high pressures and temperatures. We need all the help we can get from experts in other domains, other industries, and nascent technologies being developed for different uses.

Second, project costs are increasing at a much higher rate than new production; it is taking more technology, effort, and capital expenditure (Capex) to produce another barrel of oil and another thousand cubic feet of gas. Over the past 10 years, exploration and production (E&P) Capex spend has grown approximately by 400% while global oil production is up by only 15%. In just the past 3 years, the upstream E&P industry has spent on average USD 600 billion per year, and the only part of the oil production base that has grown significantly is the liquids production from North American unconventional resource plays (Kibsgaard 2014).

The relatively easy oil—the first trillion barrels or so we have already produced—has been developed and the next trillion will be much more costly and require more sophisticated, integrated technologies and processes. This is why we must reach out to other industries and societies to identify new processes, different ideas, and innovative technologies.

Society Collaboration

Partnering with related societies has been the norm for SPE throughout its existence. Last year, however, the SPE Board of Directors placed greater emphasis on the degree and frequency in which we work with “sister” societies, such as the Society of Exploration Geophysicists (SEG), American Association of Petroleum Geologists (AAPG), the Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Association of Geoscientists and Engineers (EAGE). One of the more successful recent examples of multisociety collaboration is the Unconventional Resources Technology Conference (URTeC) that SPE, AAPG, and SEG held last year in Denver. I personally witnessed the interaction and shared education of engineers, petrophysicists, geologists, and geophysicists who are working to identify the best methods to develop and produce complicated shale reservoirs. We are now engaging with other societies that represent adjoining domains, which also play an important role in understanding shale gas production. Let us expand on this. Why not include the American Institute of Chemical Engineers (AIChE), the International Association of Mathematical Physics and the American Rock Mechanics Association (ARMA), when their expertise we know is required to complete the shale gas puzzle? SPE will take part in this collaboration for the 2014 URTeC next month.

Another useful outcome of working together with related societies is the valuable and popular OnePetro repository of technical papers. This searchable database

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of technical literature has more than 160,000 papers, articles, and videos from 18 publishing partners, including the SPE, SEG, and SPWLA. For example, searching for literature, on completion techniques in the Eagle Ford Shale yields hundreds of papers describing the completion design and engineering, the geological and petrophysical considerations, and the structural and stress information from seismic interpretations.

Industry Collaboration

In light of the technology challenges facing our industry, it is becoming commonplace, to reach out to other industries to help develop solutions requiring specialized domain expertise. Several industries in particular have provided valuable knowledge and technologies to the upstream E&P sector over the past decade or so. At Schlumberger, we have worked with both the automotive and aerospace industries in the codevelopment of lower-cost sensors and lighter, higher-strength materials that are able to perform at similarly demanding pressures and temperatures, whether in the fuselage of a modern airliner, the engine of an automobile, or the bottom of a drillstring in the presence of hydrogen sulfide. We are learning from the aviation industry how they have applied Six Sigma performance criteria to improve processes and technologies. Imagine the cost savings of moving the service industry from the current levels of reliability to those of the aerospace industry.

Another branch of science we, as an industry, are currently collaborating with and exchanging technologies with is the biomedical business. Whether imaging and visualizing the 3D human body or a 3D seismic cube from deepwater Gulf of Mexico, the fundamental technologies are identical and we are sharing them. Whether modeling the diffusion of medicine in the bloodstream or the diffusion of pressure in a porous medium, the mathematics is identical. Nanotechnologies are working their way into our vocabulary in more applications, from nanosensors for improving enhanced oil recovery techniques and measurements to nanotubes for viscosity modification in drilling fluids. It makes much more sense to collaborate with nanotechnology experts in the more mature medical, electrical, and consumer goods markets, together with leading universities, rather than reinventing the fundamentals. SPE is helping our industry to collaborate by providing the venues and the technical literature essential in addressing these common needs. SPE is sponsoring an academic R&D competition aimed at bringing ideas from outside our industry to bear on the challenges we face. The competition is open to academia, research institutes and organizations, companies, and individual investigators. You can find more information on the competition website www.spe.org/industry/competition.php.

Collaboration in the Classroom

Academia has caught on to the advantages of collaboration by combining curricula into combined degrees, primarily as a result of our industry's push to graduate petroleum engineers

who are more knowledgeable in geology and geophysics, for example. Other forms of energy education, such as nuclear, wind, and solar, are being combined with petroleum engineering to create "energy engineers." Certainly, new engineering buildings on campuses around the world are being built using open architecture to foster collaboration, particularly around laboratories. Collaborating with other engineering and geoscience domains makes sense on campus as the graduates will be better equipped to collaborate in industry.

Enhancing the learning experience of these collaborative students is the availability now of comprehensive software workflows that enable basin geologists, for example, to work with geophysicists, petrophysicists, completion engineers, and reservoir engineers to develop a single, coherent model of the overall production system.

SPE the Collaborator

In summary, in order to continue to cost effectively meet the world's increasing energy demand, we must increase the rate and magnitude of technology innovation and implementation as well as improve our reliability to the level that exists in other industries. Collaboration is the answer and SPE is facilitating the effort.

SPE has recognized the needs of members to develop collaborative technical solutions to meet our industry challenges. To that end, we have increased the number of conferences co-hosted with relevant sister societies and we will continue to expand the societies and domains with whom we hold workshops and forums. An example of this type of collaboration would be soliciting domain expertise from societies in nanotechnology, robotics, and microelectromechanical systems for an SPE sub-sea conference.

We will also continue to expand the OnePetro library, adding papers from other societies to facilitate the collaboration with geologists, geophysicists, and well log analysts.

Finally, SPE has also recognized the need to work with other engineering societies to promote the significance of petroleum engineering in society. Last year, SPE launched a project with five other engineering societies, including AIChE, the American Society of Mechanical Engineers and the Institute of Electrical and Electronics Engineers, to provide a history of technology and engineering. By collaborating with other professional societies, SPE will be able to promote the petroleum engineering profession's history and heritage to help communicate a positive message about the industry's contributions to society.

Each month, I post my *JPT* column topic on the SPE LinkedIn group for comment and discussion. I invite you all to join in this discussion and look forward to hearing your viewpoints. **JPT**

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Supply/Demand Trends

John Donnelly, *JPT* Editor



Global oil production, consumption, and prices have remained largely stable in recent years, but several trends in the world supply/demand balance are evident in BP's *Statistical Review of World Energy 2014*.

The review, released in June, offers a snapshot of the global energy picture in 2013 along with historical data to put the information into perspective. The annual review contains country-by-country data on oil and gas production and consumption.

The report shows the continuation of several trends that have begun in the past few years: tremendous oil production growth in the United States, the continued decline of oil in overall energy market share, increases in oil supply and demand below historical averages, and the rise of coal in the energy mix.

The US "shale revolution" has not only transformed the country's short- to medium-term outlook, reversing years of oil production decline, but also is having a significant impact beyond North America as well. US oil production in 2013 rose by 1.1 million BOPD, one of the highest year-on-year increases in history, according to the review. US oil production now exceeds 10 million BOPD, the country's highest level since 1986.

The fastest demand growth last year was also in the US, as consumption grew by 400,000 BOPD. Growth was led by the industrial sector, indicating continued recovery from the 2008 global financial crisis. US demand growth outpaced China's for the first time in 1999. China's energy demand growth still hit 4.7%, but lagged its 10-year average of 8.6%.

The price of oil is at its most stable since 1970, as the large production increases in the US have offset supply declines in the Middle East/North Africa region. A cumulative 3 million bbl has been lost "since the start of the 2011 Arab uprising," according to the report, but US output has grown by similar amounts. The price of Brent averaged USD 108.66/bbl in 2013, a slight decline from the year before, and the third straight year that the oil price has exceeded USD 100/bbl.

Here are more highlights from the annual report:

- Global oil consumption grew faster than oil production in 2013. Consumption grew by just 1.4 million BOPD but global oil production increased by just 560,000 BOPD.
- Coal consumption grew by 3%, faster than any other fossil fuel, and coal's share of global primary energy consumption reached 30.1%, the highest since 1970.
- Global proved oil reserves increased by 1.1% to 1687.9 billion bbl. US reserves increased by 26% to 44.2 billion bbl.
- Global proved gas reserves declined by less than 1% to 185.7 Tcm.
- Worldwide primary energy consumption grew by 2.3%, slightly lower than the 10-year average. All fuels except oil, nuclear power, and renewables for power generation, grew at below-average rates.
- Oil remains the world's leading fuel, accounting for 32.9% of global demand, but it lost market share to other fuels for the 14th consecutive year. **JPT**

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North Sea Oil and the Scottish Independence Referendum

Sanjoy Sen, Consulting Engineer



Sanjoy Sen, SPE, is a chemical process engineer with 20 years of industry experience primarily in the UK North Sea, and is based in Aberdeen,

Scotland. He holds a BEng degree in chemical engineering from the University of Sheffield and an MSc degree in petroleum engineering from Heriot-Watt University. He recently completed an LLM in oil and gas law at the University of Aberdeen where his dissertation considered the future of the UK North Sea following the 2014 Scottish independence referendum. He is a fellow of the UK's Institution of Chemical Engineers.

On 18 September 2014, the Scottish public will vote on the question, “Should Scotland be an independent country?” With North Sea oil predicted to be the largest sector in an independent Scottish economy, the industry finds itself at the center of a political and economic debate.

First, some basics. The United Kingdom (UK) consists of England, Scotland, Wales, and Northern Ireland. In 1999, a new Scottish Parliament opened with limited devolved powers including health and education. Following its surprise 2011 election victory, the pro-independence Scottish National Party is now delivering on its referendum pledge. Scotland's population of 5 million forms just 8% of the UK total, but is comparable to that of its prosperous Scandinavian neighbors, including Norway.

While well beyond its 2000 peak production, the North Sea oil and gas sector remains valuable; up to a further 24 billion BOE is recoverable. Although substantial in the Scottish context, this forms less than 1% of global reserves. Tax revenues amounted to GBP 11 billion in 2012 while the sector employs 500,000 workers. The resource meets more than 50% of UK hydrocarbon demand, sharply reducing import dependence.

The outlook for the North Sea is mixed. Investment sits at record levels (GBP 13 billion in 2013) as multinationals develop new opportunities in the Atlantic margin (e.g., Total's Laggan-Tormore project) while smaller independents redevelop mature assets (e.g., Apache's purchase of BP's Forties field). Production, however, has tumbled to below 2 million BOEPD and exploration continues to fall.

Approximately 85% of reserves on the UK Continental Shelf (UKCS) lie in waters closest to Scotland. Upon independence, this would account for almost a fifth of Scotland's national gross domestic product. While much debated publicly, the precise location of the UK-Scotland maritime boundary is less significant in terms of reserves than might be imagined. Arrangements for distinctive island communities in the far north (Orkney and Shetland) require resolution, however. More pertinent to the effect on the oil and gas industry would be new Scottish tax arrangements, treatment of cross-border pipelines, and unitization agreements. In terms of licensing, the Scottish government has pledged to honor existing agreements but provision of tax relief on the sector's predicted GBP 35 billion of decommissioning liabilities is a source of industry uncertainty.

North Sea oil has historically been under the control of the UK Parliament, although many activities are executed in Scotland's oil hub, Aberdeen. Regulation is done through the Department of Energy and Climate Change (licensing), the Health and Safety Executive, and the Maritime and Coastguard Agency (oil spill response). While the Scottish government proposes an all-new energy department, retaining expertise and maintaining continuity could prove challenging as existing bodies find themselves undermanned. Furthermore, the recent report chaired by former Wood Group chairman Sir Ian Wood calls for further government-industry interaction to deliver “maximum economic recovery”. Its recommendations are due to be implemented shortly by the UK government. The UK Department of Energy and Climate Change commissioned former Wood Group Chief Executive Sir Ian Wood to conduct a review of UK offshore oil and gas recovery and its regulation last year.

Lawyers are currently dissecting Wood's study about the ramifications of Scottish independence on the oil and gas sector, although the Scottish government has pledged to honor those granted by the UK government.

The future success of the North Sea largely rests on factors beyond governmental control. Economic modeling suggests that the North Sea, a traditionally high-cost operating environment, is particularly susceptible to an oil price downturn. Recent UKCS entrants include several national oil companies, including China National Offshore Oil Corporation and Sinopec and, while foreign investment has been encouraged by the UK government, its political impact upon an independent Scotland could be significant. With 50% of production from only 10 fields, lengthy field outages would significantly affect Scottish revenues as can dependence on aging hubs. Although UK government-imposed taxes of 62% to 81% have cre-

ated shock waves, it has proven adept at stimulating investment in the region through a range of incentives. A key challenge for a smaller Scottish economy would be to attract long-term investment without sacrificing short-term revenue, a tricky balance.

North Sea oil and gas revenue have funded UK public spending and supported low levels of personal taxation. By contrast, Norway invested its revenues in an oil fund for long-term growth. Its revenues effectively make every Norwegian a millionaire although personal taxation and living costs are high (many an oil worker visiting Stavanger has a tale of a GBP 10 beer from the bar). The Scottish government proposes to create an oil fund although opponents counter that may not be workable.

Sadly, the topics of currency and Europe cannot be answered definitively ahead of the vote. The UK, a European Union (EU) member state, enjoys an exemption from joining the Euro single

currency, allowing it to retain the pound sterling. The Scottish government proposes to continue to share use and control of the pound via a "sterling union" with the UK, an idea the UK government has rejected. The Scottish government also proposes that upon a "yes" vote, it would enter into negotiations with the EU to facilitate direct transition into a new member state. Legal opinion remains divided, however, as no precedent exists. Entering the EU could lead to complexities should common safety and licensing provisions come to fruition.

Opinion polls have consistently shown a preference for a "no" vote by the Scottish public, but the margin has been narrowing. And a close "no" vote could lead to calls for changes in how North Sea management and revenue are shared. No matter which side prevails, the referendum outcome could have significant impact on the North Sea oil and gas sector as it continues to move into a mature phase of production. **JPT**

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How Thirsty is Shale Gas?

Vikram Rao, Executive Director, Research Triangle Energy Consortium

Editor's note: Professionals in the oil and gas industry often receive questions about how industry operations affect public health, the environment, and the communities in which they operate. Of particular concern today is the impact of hydraulic fracturing on the environment. In this new column, JPT is inviting energy experts to put those questions and concerns about industry operations into perspective. Additional information about the oil and gas industry, how it affects society, and how to explain industry operations and practices to the general public is available on SPE's Energy4me website at www.energy4me.org.

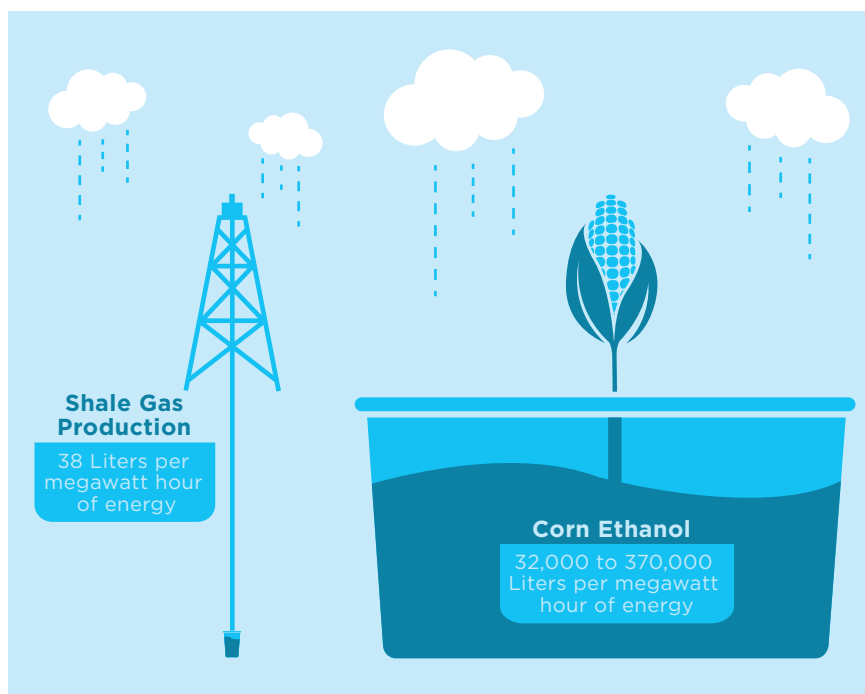
The Industry in Perspective

The New York Times reported on 15 May 2014 that Butte County in California banned hydraulic fracturing because of concerns regarding freshwater consumption in a drought year. Shale oil and gas opponents have seized this issue even in parts of the country not suffering any significant drought. The perception of being deprived of drinking water has strong imagery. The facts beyond the headlines are decidedly not so dire.

A single shale oil or gas well will use between 3 and 5 million gal of water for drilling and completion operations. This sounds like a lot and, in some sense, it is a lot. But then you realize that the average golf course uses that much every 25 days, about the length of time it takes to drill a single well and start producing from it. It is also the amount of water that New York City uses every 4 minutes! Not a fair comparison, you say. Well, why don't we compare it against other forms of energy?

Such comparisons are best made on the basis of liters of water per megawatt hour of energy. Shale gas production uses about 38 liters. In comparison, corn ethanol on average uses 32,000 to 370,000 liters (the higher end of the range is for irrigated corn), and the real shocker is soybean diesel, which comes in at 180,000 to 960,000 liters. In other words, corn ethanol uses more than 1,000 times more water per unit of energy compared with shale gas. Other sources suggest an even greater disparity in water usage (Science 2009).

Conventional fracturing fluid uses freshwater as the base fluid. Fresh is defined as 500 parts per million (ppm) or less of dissolved solids. The fluid returning to the surface after use, known as flowback water, is always saltier than what went in. Salinities of 200,000 ppm are not uncommon. As a frame of reference, seawater runs about 35,000 ppm. Recent advances in fracturing fluid chemistry allow for such flowback water to be reused without removing the salt down to fresh standards. Currently in the Marcellus shale play, some companies are reusing almost all of their flowback water with minimal treatment.



Water use in the production of shale gas and corn ethanol.

This practice materially reduces freshwater requirements.

Between 16% and 35% of fracturing water returns to the surface. Consequently, even reuse entails making up that with new freshwater. Since salt concentrations are tolerable, this make-up water could also be salty. To the extent that this is done, the industry would not be competing to use freshwater resources. How viable is this option? It turns out that salty water is commonly available almost anywhere that freshwater is found. The comprehensive map of saline groundwater by the US Geological Survey is old but instructive in this regard (USGS 1965). Fresh groundwater gets saltier as you go deeper. This is because over time, minerals dissolve into the water, more so at greater depths. Very often, the fresh and saltier zones are in direct communication. This is why in times of drought, farmers face restrictions on the rate of withdrawal of freshwater in order not to draw up saltier water from below.

Shale oil or gas production does indeed use a lot of water, but not as much as other sources of energy. Recent advances in technology allow the substitution of brackish water for freshwater. This is already happening today. If the practice becomes more widespread, public acceptance of the industry, especially in drought-prone areas, will improve. **JPT**

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Vikram Rao, SPE, is executive director of the Research Triangle Energy Consortium (www.rtec-rtp.org), a nonprofit group in energy founded by

Duke University, North Carolina State University, RTI International, and the University of North Carolina at Chapel Hill. Its mission is to illuminate national energy priorities and, by extension, those of the world, and to catalyze research to address these priorities. Rao advises Energy Ventures AS, BioLargo, Global Energy Talent, Integro Earth Fuels, and a multinational oil company. He retired as senior vice president and chief technology officer of Halliburton in 2008. He also serves on the North Carolina Mining and Energy Commission and chairs the Water and Waste Management Committee. He holds a bachelor's degree in engineering from the Indian Institute of Technology Madras in India, and a master's degree and doctorate in engineering from Stanford University. Rao is the author of more than 50 publications and has been awarded 36 US patents and foreign analogs. His book, *Shale Gas: The Promise and the Peril*, released in 2012, is an informed look at the heated debate regarding hydraulic fracturing for shale gas.

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TECHNOLOGY APPLICATIONS

Chris Carpenter, *JPT* Technology Editor

Gauge Hanger

Peak Well Systems introduced its Hi-Ex gauge hanger for the slickline deployment of data-acquisition devices through narrow constrictions in the well. Its slim yet highly expandable design minimizes flow restriction, enabling operators

to record accurate data during production or injection conditions. The Hi-Ex is deployed during well testing and production monitoring and can also be used as an anchoring platform in nonmonobore wells. It comes in two chassis sizes, 2.200- and 3.600-in. outer diameter, and

can be set in a range of tubing sizes from 4½ through 9⅝ in. The Hi-Ex is deployed from surface by use of Peak's nonexplosive eSetting Tool. At the required depth in the well, the eSetting Tool activates and sets the Hi-Ex, expanding its arms and centralizing itself in the tubing (Fig. 1). The Hi-Ex is anchored in the well by bidirectional slips. The hanger is retrieved with an external fishing-neck pulling tool. Once latched, light upward jarring unsets the device. The hanger can then be recovered to surface along with any gauges that may have been deployed.

► For additional information, visit www.peakwellsystems.com.



Fig. 1—The Hi-Ex gauge hanger from Peak Well Systems.

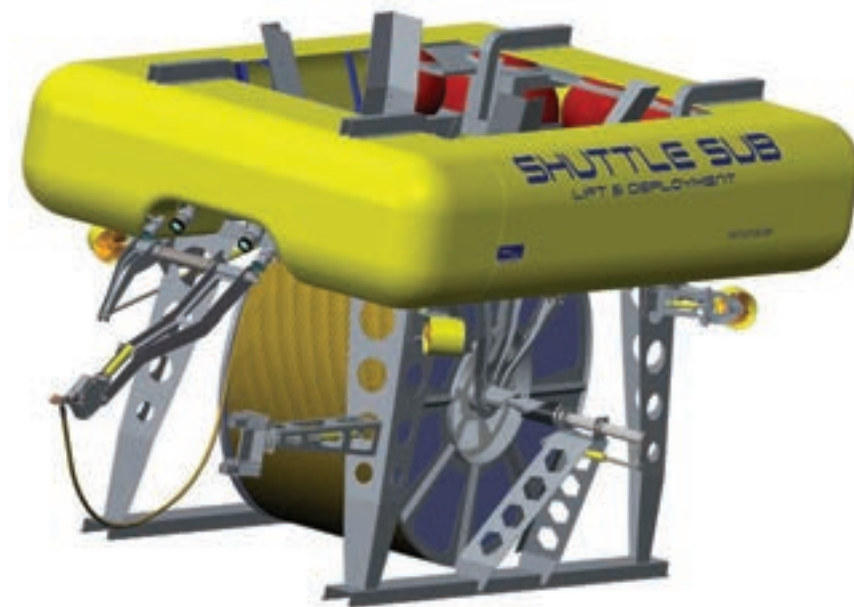


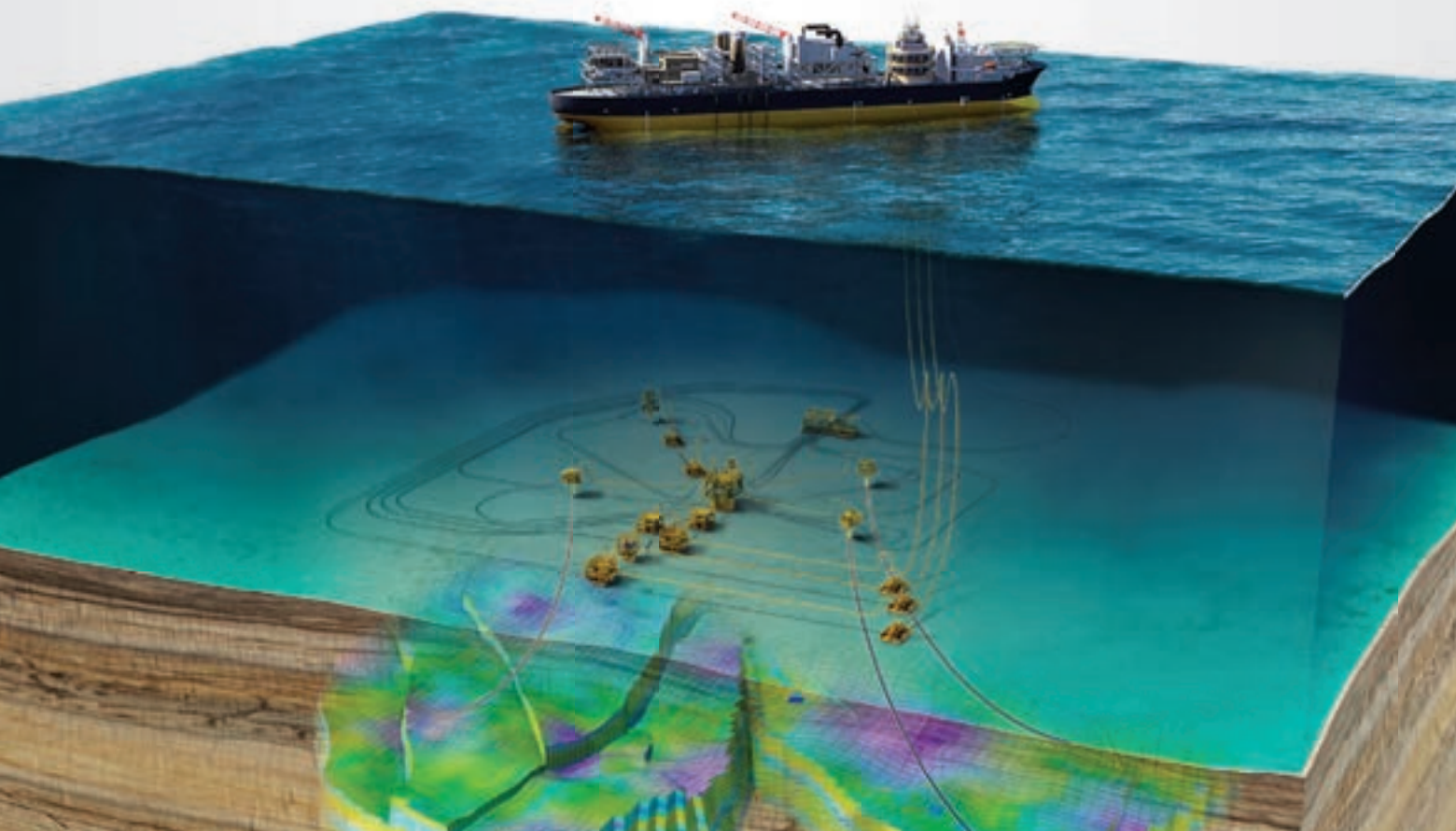
Fig. 2—The Shuttle Sub lift-and-deployment ROV system provides a cost-effective way to transport heavy payloads, such as cables and umbilicals, to and from the seabed.

Lift-and-Deployment ROV System

Deep Blue Engineering UK announced the introduction of its Shuttle Sub. The new lift-and-deployment system is a payload-carrying remotely operated vehicle (ROV) (Fig. 2). It is used to install and retrieve equipment, lay cable, and conduct salvage operations. Even when laden with a payload of 100 t, the Shuttle Sub can float, dive, surface, and maintain neutral buoyancy, so it is ideally suited for work being carried out in deepwater environments on or near the seabed. The Shuttle Sub does not require an additional ROV to conduct visual monitoring or connector installation activities subsea. Instead, technicians on a support vessel carry out these tasks remotely. As with a conventional ROV, technicians monitor and control subsea activities by an umbilical between the Shuttle Sub and the vessel at the surface, but the Shuttle Sub is unique in that it is also the payload carrier, transferring deployment and retrieval tasks to the ROV. This provides optimum control and removes the need for lift-line-based operations. The Shuttle Sub performs all of the functions of a work-class ROV but is large enough to accommodate a payload that would normally be deployed or retrieved from a ship.

► For additional information, visit www.deepblueengineering.co.uk.

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Fig. 3—Weatherford's MotorWise AC-induction motor-energy management-and-control system.

Constant-Speed Motor Controller

Weatherford is offering its MotorWise constant-speed motor controller, an alternating-current (AC) induction motor-energy management-and-control system. Its design uses digital signal processors and unique control software to allow optimal energy management. The units identify partial and intermittent loading conditions and dynamically reduce the motor's voltage to an optimal level without changing speed (Fig. 3). Its operation reduces energy costs and enables motors to run cooler and more smoothly. This is achieved by eliminating waste in the form of heat, noise, and vibration while maintaining proper operation, collectively decreasing maintenance costs, and improving the reliability and longevity of the motor, gear box, and load-bearing components. The MotorWise motor controller is compatible with conventional, beam-balanced, and enhanced-geometry pumping units. The controllers are used in a variety of three-phase

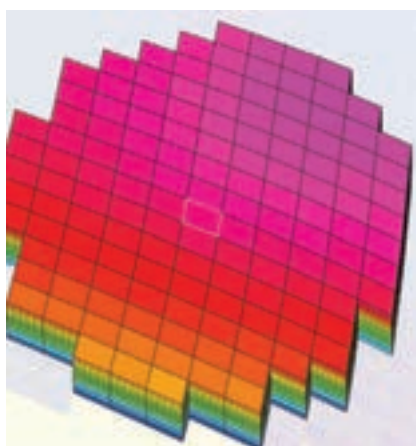


Fig. 4—Sciencesoft's S3sector reservoir-simulation-software tool. Higher resolution applied to a sector model using a tartan grid.

power-distribution schemes, including wye, delta, and grounded-delta configurations. Depending on the application, MotorWise controllers can immediately improve the energy consumption of a constant-speed, variable-load AC-induction motor by an average of 22%.

► For additional information, visit www.weatherford.com.

Reservoir-Simulation-Software Tool

Sciencesoft has introduced its S3sector reservoir-simulation-software tool. S3sector provides a solution to extracting information from a full-field model. This software tool builds sector models in minutes rather than the weeks needed for a manual conversion. The first release of S3sector provides full support for creating Eclipse and UTCHEM sector models, soon to be followed by support for Nexus, IMEX, GEM, and STARS. Single or multiple wells can be selected quickly, and a new sector model can be built in minutes. S3sector automatically maps the data from one simulator onto the format required for the sector model. Corner-point geometry can be converted to block-centered geometry, with additional refinement added to model fine-scale effects. Enhanced-oil-recovery models for UTCHEM can be built quickly and easily, saving weeks of

painstaking manual work. S3sector features interactive region selection through user-defined polygons, as well as integrated visualization of full-field and sector models. Multiple work flows include polymer flooding, surfactant flooding, radial-grid well tests, and tartan-grid models (Fig. 4).

► For additional information, visit www.sciencesoft.com/products/s3sector/.

Environmentally Friendly Cables

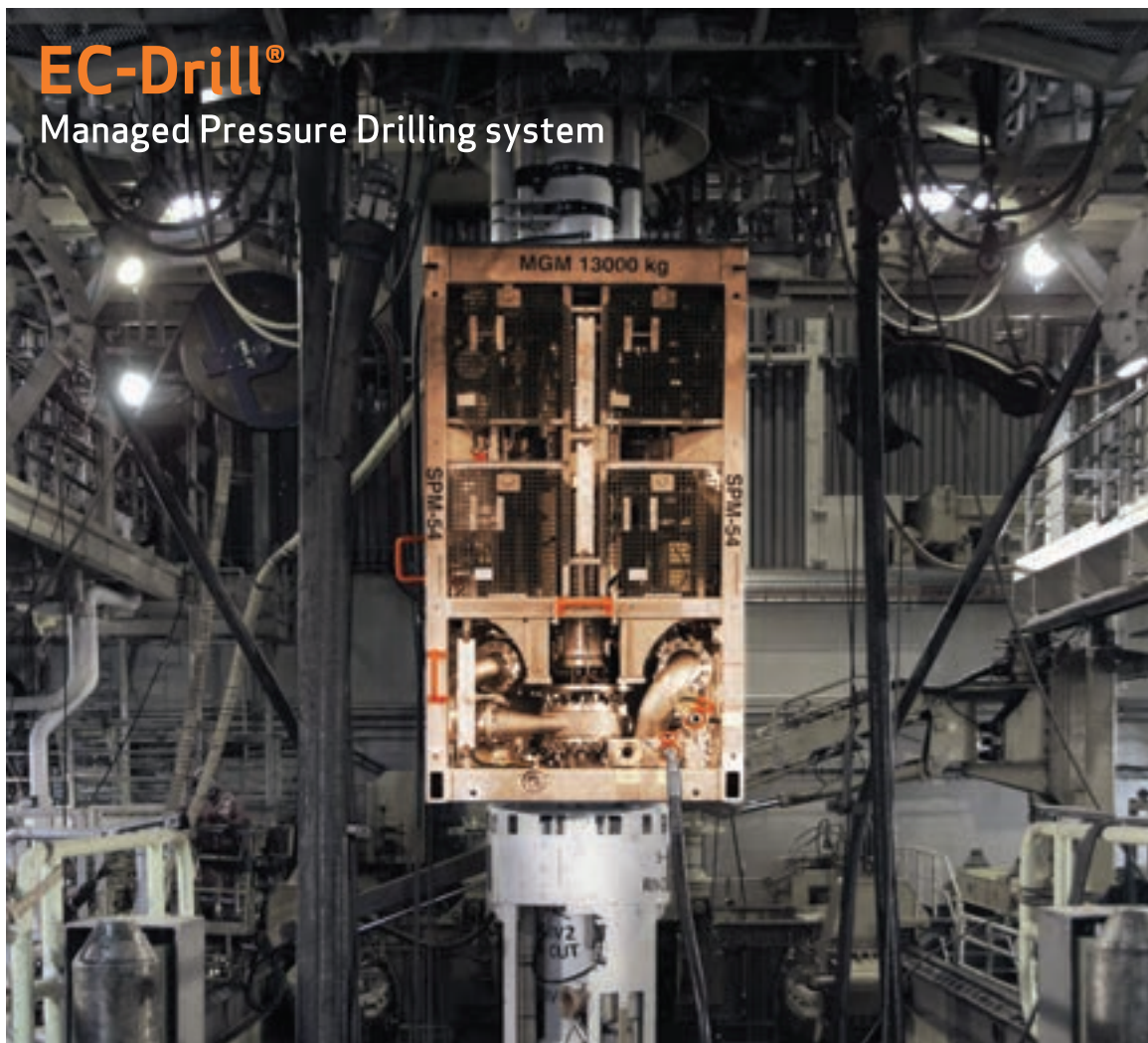
RSCC Wire & Cable's Exane Products Segment introduced a line of multiconductor cable products that comply with the European low-voltage directives for the Restriction of the Use of Certain Hazardous Substances (ROHS) and the Waste Electrical and Electronic Equipment Directive (WEEE). Exane-ROHS cables are not only environmentally friendly, but are also manufactured with ruggedized thermoset insulations and jackets that will not cold flow or deform under pressure (Fig. 5). These cables pass the Institute of Electrical and Electronics Engineers (IEEE) 1202 Vertical Cable Tray Flame Test at 70,000 Btu/hr. They are equally suited for cold environments and pass a -55°C cold-bend test as well as the -40°C cold-impact test. Additionally, RSCC introduced two ruggedized low-voltage signal and control cables. The Exane-Torque Flex cable has been developed to allow for twisting and flexing at



Fig. 5—RSCC Wire & Cable's Exane-ROHS multiconductor cable.

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Fig. 6—Comparison of Baker Hughes' NSURE drilling fluid, right, with conventional fluid, left, at 9°F.

the same time, for installation in bridge rackers and pipe-handling systems on mobile offshore drilling units.

► For additional information, visit www.rsc-exane-oil.com.

Drilling-Fluid System

Baker Hughes introduced its NSURE invert-emulsion-drilling-fluid system designed to address offshore and high-risk drilling operations better through its ability to exhibit an enhanced constant rheological profile across a range of temperatures and conditions. Compared with conventional systems in which the fluid's viscosity is dependent on temperature, NSURE retains constant and predictable properties across

a wider range of temperatures (Fig. 6). The NSURE system has the ability to bring greater control to fluid properties such as plastic viscosity, yield point, and gel strength across a wide range of densities, base oils, oil/water ratios, and contamination conditions. NSURE's controlled rheology results in fluid properties ideal for better cement placement and reduces the risk of channeling while pumping. The controlled rheological properties also contribute to the ability to lower equivalent circulating densities, reducing pressure spikes when initiating circulation and ultimately taking pressure off the formation. This reduces the risk of fracturing the formation that could lead to lost circulation and non-

productive time. The NSURE system is also environmentally compliant across multiple markets worldwide.

► For additional information, visit www.bakerhughes.com.

Regenerative Blower

AMETEK Precision Motion Control's ROTRON Chem-Tough regenerative (side-channel) blowers are ideally suited for applications that require the safe handling of corrosive or potentially explosive gases such as methane gas extraction and flaring. Chem-Tough technology takes advantage of low-friction polymers and dry lubricants as well as anodized and hard-coat plating that become an integral part of the blower's



Fig. 7—AMETEK's ROTRON Chem-Tough regenerative blowers.



Fig. 8—The TriFrac-MLT crosslinked guar-based hydraulic-fracturing fluid developed by Trican and Emerald Surf Sciences.

molecular structure. Chem-Tough blowers benefit from compact, rugged construction designed for reliable service at point-of-operation (Fig. 7). They use stainless-steel motor shafts and hardware throughout, along with nickel-plated components. The blowers employ regenerative air technology to develop proper air pressures and vacuums without the higher energy and maintenance costs associated with larger multistage or positive-displacement blowers and compressors. An extensive product range allows users to achieve ideal flows, pressures, and vacuums as required. ROTRON blowers are ideal for a wide range of oil-rig, oil-field, environmental-remediation, and chemical-processing applications. Along with methane extraction and flaring, applications include landfill-gas recovery, chemical-tank agitation, waste-water treatment, and aquaculture oxidation.

► For additional information, please visit www.ametek.com.

Guar-Based Fracturing-Fluid System

TriFrac-MLT is a crosslinked guar-based hydraulic-fracturing-fluid system developed by Trican and Emerald Surf Sciences that exclusively uses flowback and produced water to eliminate the need for fresh water. The fluid system reduces the cost of treating the flowback and produced water to meet

conventional reuse standards, simplifies the logistics for reusing produced water, and eliminates the creation of the secondary waste streams generated by some treatment processes. In addition, the fluid system has a broad operating temperature range of 49 to 149°C and uses common fracturing-fluid additives. The flowback or produced water is combined with chemical additives and proppant to make the fracturing fluid (Fig. 8). The fluid-system formula enables rapid hydration of the additives, and crosslinking occurs at temperatures as low as 7°C (45°F). Because the fluid has a delayed crosslinker, and the breaker schedule can be customized, the fluid viscosity can be optimized. Fluid viscosity develops during the pump time to bottom, reaching its maximum at bottomhole conditions.

► For additional information, visit www.trican.ca.

Durable Polymer Resin

Solvay Specialty Polymers' KetaSpire KT-820 polyetheretherketone (PEEK) resin delivers strong chemical and abrasion resistance combined with heat resistance and strength. Parts based on KetaSpire PEEK are currently being used in a range of oil and gas applications including but not limited to bearings, seals, and backup rings. The resin meets NORSOK M-710 standards; KetaSpire-based PEEK shapes have proved superior in NORSOK M-710 (an internationally recognized set of testing systems originally developed by the Norwegian petroleum industry) sour single-phase aging tests at high hydrogen sulfide levels. The M-710 standard defines the requirements for critical nonmetallic (polymer) sealing, seat, and backup materials for permanent subsea applications. KetaSpire offers a maximum operating temperature of 240°C and exhibits high purity and consistent high quality in processing and part performance. Glass-fiber-reinforced and carbon-fiber-reinforced grades provide a wide range of performance options. **JPT**

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Liner-Based Stimulation Technology Without Fracturing Proven in Field

Thomas Jorgensen, SPE, Fishbones

Efficient production in many fields requires reservoir stimulation. Some of the challenges with hydraulic fracture stimulation are reservoir-related, such as consistently stimulating all targeted intervals. The growth of hydraulic fractures in the vertical direction is difficult to predict, leading to the risk for entering unsought gas- or water-bearing formations. Operations can be complex, costly, and pose environmental challenges.

A new liner-based stimulation technology has been developed and field tested by Fishbones to be simple, efficient, and more controllable with less environmental impact. The method uses less fluid and reduces greatly the risk of groundwater contamination and the disposal of recovered stimulation fluid. Field experience has shown positive pro-

ductivity response, with an 8.3 times increase in 30-day cumulative initial production (IP-30) in an existing well in a tight limestone formation. The productivity index was increased by 30 times.

The liner-based stimulation technology was originally developed for carbonate reservoirs, but is also applicable in coalbed methane and unconsolidated formations. Technology suitable for sandstones and other clastic formations is being developed.

Technology Description

The technology uses a liner sub that houses four small-diameter, high-strength tubes called needles, each with a jet nozzle on the end (Fig. 1). The sub is made up to a full-length casing joint and needle assemblies up to 40 ft long are assembled

in the workshop before the sub is sent to the field.

The subs are run as integral parts of the liner in the open hole and are positioned across the formation where stimulation is desired. The needles are located inside the sub/liner joints while the sub is run in hole. The liner is hung off with a standard liner hanger.

In a carbonate formation, a basic hydrochloric acid (HCl) fluid system is pumped. The fluid jets out of the nozzles, and the formation ahead of the tubes is jetted away by a combination of erosion and acid chemical dissolution. Differential pressure across the liner drives the needles into the formation, and they penetrate the rock until fully extended. Typical jetting pressure is 3,000 psi.

All laterals are created simultaneously in a short pumping job, resulting in a fishbone-style well completion with multiple laterals extending from the main bore (Fig. 2). The rate of penetration depends on the formation composition, porosity, downhole temperatures, nozzle configuration, jetting fluid, and jetting pressures. The needles exit the sub at an approximate 40° angle. The bending through the exit port results in laterals with an approximate 90° angle relative to the wellbore.

The needles may be equipped with a positive identification mechanism that shuts off the flow when a needle is fully extended. This will give a pressure indication on surface that jetting is completed.

A fit-for-purpose float shoe enables circulation during the run in hole, but closes upon contact with the acid, thus providing a closed-pressure system for jetting.

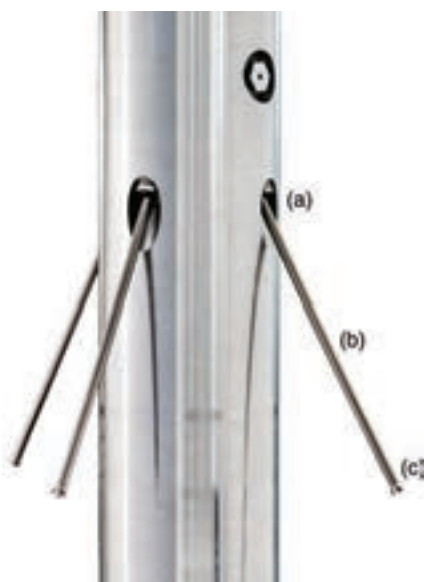


Fig. 1—The sub (a) with needles (b) and jet nozzles (c).

A photograph of two young children sitting on a beach. The child on the left is wearing a straw hat and has ice cream smeared on their face and chest. The child on the right is wearing a pink swim cap and is also eating ice cream. The background shows a sandy beach and the ocean with other people in the distance.

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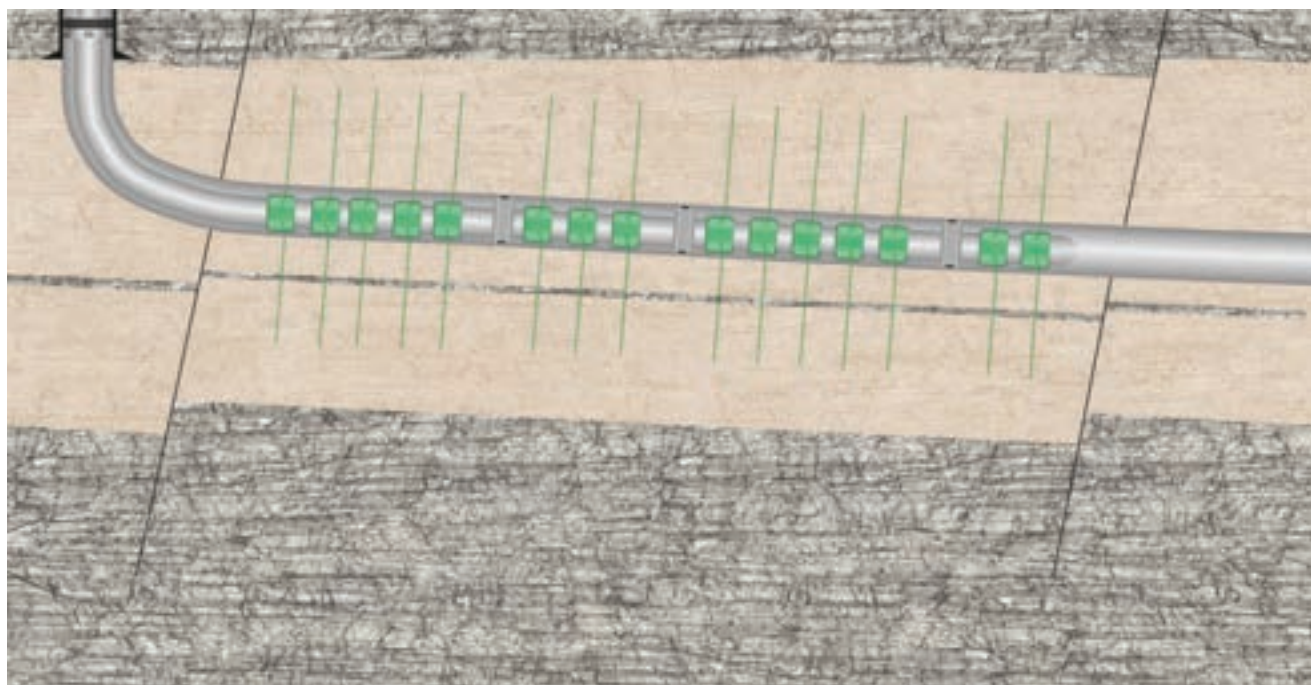


Fig. 2—A completion schematic from an installation in the Austin Chalk formation in Texas.

Depending on the length of the horizontal wellbore, downhole temperatures, and the number of laterals, a number of openhole anchors are positioned in the liner to eliminate axial liner movement during jetting. An anchor with 330,000 lbf anchoring capability in washed-out holes has been developed and qualified.

The jetting and dissolution of the carbonate formation create lateral tunnels of 1/2-in. to 3/4-in. in diameter or larger. The oil will predominantly flow in the lateral/needle annuli and into the main bore, where it will flow through production valves in the subs, into the production liner, and up the well. Each sub has two production valves phased 180° apart. These valves do not allow outward flow during the well operation, but enable inflow during production.

Connecting the Reservoir

The purpose of the technology is to increase well productivity, or injectivity in the case of injection wells, by better connecting the reservoir to the wellbore. The technology is applicable in low-permeability formations to create a negative skin similar to the hydrau-

lic fracturing process for reservoirs that are

- ▶ Compartmentalized, layered, or naturally fractured.
- ▶ Without barriers to contain hydraulic fractures.
- ▶ Depleted, where placement of hydraulic fractures is challenging.
- ▶ With insufficient depth accuracy for sweet spot well placement.

Damage to the formation rock near the wellbore is bypassed. But the analysis of post-job pressure data shows that the majority of the stimulation can occur more than 10 ft from the wellbore. The length of the laterals is adjustable by tailoring the tube lengths. This means that the depth of the stimulation is controllable. Thus, the risk of penetrating untar-geted zones is eliminated.

System Operations

The installation of the system is similar to an openhole liner installation and uses a standard drilling or workover rig. Zonal isolation is not required, but swellable packers can be used if a zone needs to be isolated. No ball dropping or pipe manipulation is needed to activate lateral jet-

ting. The fluids are bullheaded after the liner hanger is set.

The technology requires less rig time and shorter pressure pumping operations than hydraulic fracturing, while using a fraction of the chemical volumes needed for fracturing, using no explosives, and eliminating elevated work above the rig floor.

Field experience

The stimulation technology was recently used in existing producing horizontal oil well in the Austin Chalk formation in Texas. The installation of the system was part of a pilot program managed by the Joint Chalk Research (JCR) group composed of BP, Shell, ConocoPhillips, the Danish North Sea Fund, Dong, Eni, Hess, Maersk, Statoil, and Total. A goal of the JCR is to improve recovery from the chalk reservoirs on the Norwegian and Danish continental shelves. The pilot installation was also supported by the Norwegian Research Council.

The operator of the pilot well had experienced consistent challenges with prior stimulation both with running in hole with fracturing assemblies and achieving zonal isolation and proper

diversion. The pilot well, horizontally placed in a tight limestone formation with approximately 5% porosity, was shut in after 3 years of production and prior stimulation and was considered to be without potential for normal restimulation. A 4.5-in.-diameter lower completion string was planned for the 6.5-in.-diameter open hole. Fifteen subs with a total of 60 needles and three openhole anchors were spaced out with 4.5-in.-diameter liner joints.

Half of the needles were equipped with the positive pressure verification mechanism for identification of fully extended needles. The acid-activated float shoe was run in the toe of the string. The shoe had a tungsten carbide cutting structure to facilitate reaming the liner in the hole, based on previous operator experience of unstable wellbores in Austin Chalk re-entries.

The stimulation completion was deployed on drillpipe with a workover rig. When the shoe reached the 7 $\frac{5}{8}$ -in. casing shoe, string rotation was started as per standard workover procedure. The completion string was rotated at 40 rev/min for more than 10 hours to total depth with a typical 2,500 ft-lbf of torque, with spikes up to 7,000 ft-lbf. The liner hanger was set and the packer integrity checked before acid was pumped.

A basic inhibited 15% HCl blend was pumped to close the shoe and for the jetting operation. Jetting testing on core samples from an offset well provided by the operator before the installation showed that approximately 810 bbl of acid would be needed for the full extension of 60 tubes with 40-ft length.

During the pumping, a steep decrease in pump pressure at constant rate verified increasing injectivity. After 875 bbl of acid was pumped (within 8% of expected volume), a rapid pressure increase was seen at the surface, confirming full extension of the needles. Additional acid was pumped to maximize the stimulation. An analysis of the post-job pressure chart indicated that all the needles had fully penetrated.

The pumping operation was completed after 5 hours, including jetting and

fluid displacement. The creation of as many as 60 laterals in one well is believed to be a world record.

The well was completed with a beam pump following the completion and put on production. As of May, the well had been flowing for 30 days post-stimulation. In addition to showing

an 8.3 times increase in IP-30 compared with well production before shut-in, the initial results showed a 2.6 times increase compared with IP after the well's original completion. The results confirm the significant stimulation of the well by the use of the liner-based technology. **JPT**

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New Anchor Extends Insertable Progressing-Cavity-Pump Applications

In artificial-lift applications, a new anchoring device for insertable progressing-cavity pumps (I-PCPs) extends I-PCP applications to a larger set of candidate wells. The I-PCP anchor allows an I-PCP to be run, landed, operated, and removed from a tubing string in the absence of a previously installed pump-seating nipple (PSN) typically required for installation.

Conventional PCPs are installed by running the stator assembly on the bottom of the tubing string and the rotor on the bottom of the rod string. In contrast, with an I-PCP, the entire pump assembly is installed by the rod string and landed inside the tubing string. This allows the pump to be pulled and rerun by the rod string. The primary advantage of this system is the elimination of costly and time-consuming tubing pulls to change worn or damaged pumps or to switch to different pump sizes and configurations as down-hole pumping requirements change.

I-PCPs are conventionally installed with a PSN in the tubing string and a corresponding set of seating rings in the pump assembly. While this method provides a reliable method of landing, it also requires that the PSN be originally installed and it limits the positioning of the pump to the associated pump-seating location.

Weatherford's Flexisert I-PCP anchor is an installation method that does not require a PSN to be in place. The impetus for the anchor's development was the recompletion of depleted offshore gas lift wells to PCP systems. The anchor makes this possible because it allows the gas lift system to be left in place while inserting the new anchor.

In general application, the I-PCP anchor allows I-PCPs to be run in wells that are not equipped with a PSN, or where the PSN is at the wrong location or has specifications that are unknown. The

Editor's note: If you have a new technology introduced fewer than 2 years ago and would like to highlight it in Young Technology Showcase, please contact *JPT* Technology Editor Chris Carpenter at ccarpenter@spe.org.

anchor system also provides an artificial-lift option to reactivate old wells without pulling the tubing.

The anchor reduces the downtime and costs for replacing different forms of artificial lift, including eliminating the need to pull and rerun production tubing if a PSN is not already in place. It is deployed in one trip to provide a seal and prevent rotation and axial movement. In current markets, the smaller rig requirement seen from running rods rather than tubing reduces wait time, which limits production losses.

Technical Details

The anchor is manufactured in 2 $\frac{7}{8}$ - and 3 $\frac{1}{2}$ -in. production-tubing sizes and is able to pass through common tubing restrictions, depending on the internal diameter of features such as PSNs and subsurface safety valves.

The devices are designed to prevent movement and provide sealing between the high-pressure discharge end of the pump and the lower wellbore. The main components consist of a PCP adapter head, a bladder, a slip cone, bidirectional jaws, a shear screw, a slip assembly, and a mandrel body with J-slot grooves (**Fig. 1**). Tool specifications for each size address



Fig. 1—The Flexisert anchor is positioned at the bottom of the I-PCP, while the rotor-locking mechanism confirms the correct placement of the rotor during installation.

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Fig. 2—Weatherford employees prepare to run the Flexisert I-PCP anchor into a well in Poza Rica, Veracruz, Mexico.

a full range of torque, downward and upward axial loads, and differential pressures associated with common insert-pump configurations.

The anchor is run on the bottom of the I-PCP and deployed by lowering it to the target position, lifting up to the setting position through a J-slot, and setting down with full rod weight to engage the ratchet ring, slips, and bladder.

Removal is achieved by pulling the rod string upward to shear the anchor pins and release the ratchet, slips, and bladder. Once at surface, the tool is inspected, redressed, and rerun.

Applications

Target applications are artificial-lift wells where an I-PCP cannot be installed because of a lack of a PSN; where another

form of artificial lift has failed; and/or where changes in pump-setting depth, pump volume, and lift are required. In applications where there is high sand production or paraffins, I-PCP-anchor use should be reviewed carefully because of the system's narrow pump/tubing annulus. Horizontal or highly deviated applications also should be evaluated to ensure that rod weight is sufficient to engage the tool.

Ongoing field trials include applications in Oman, Venezuela, and Mexico. Six field trials have resulted in four successful installations. The other two were compromised because of dirty tubing/temperature differential issues, and a lack of PSN depth information.

In Oman, a 3½-in. anchor was installed onshore in a vertical well, and it had been operating for more than 500 days at the time of this writing. The installation changed out a conventional PCP for I-PCP equipment and left the conventional stator in the well. Intervention time with the conventional PCP was 72 hours, while intervention time with the I-PCP-anchor system was 18 hours, for a 75% reduction. Oil production remained the same, with 85% water cut and a trace of sand.

In Venezuela, a 2⅞-in. anchor was installed onshore in a vertical well; that I-PCP system had been operating for more than 330 days at the time of this writing. Production was maintained at the previous rate, with a 4% water cut and no sand.

Tubing had been pulled previously from the well, which had been produced with conventional PCPs. The rotor was partially inserted while running the anchor because of previously identified restrictions in the tubing. The anchor was set prematurely high, which prevented installation of surface equipment. One joint of tubing was removed, and one sucker rod was removed and replaced with pony rods, allowing the anchor to be set at the target depth.

To accommodate early anchor setting, it was recommended that the polished rod length be slightly longer than rotor length, and that the installed pony rods be equivalent to the length of the

polished rod. The configuration maintains the ability to flush the well. The installation also accelerated development of a method to lock the rotor for installation and ensure that it is inserted fully into the stator.

In Mexico, a 2 $\frac{7}{8}$ -in. anchor was installed onshore in a deviated well and the I-PCP system operated for 92 days before failure because of a break in the stator tube unrelated to the anchor (Fig. 2). The lift system was installed successfully in a completion designed to mitigate gas production. Free-flow production was doubled with 2% water cut and no sand. Again, the rotor was partially inserted in the stator when running the anchor, and it was set prematurely high. On the basis of lessons learned, the multiple pony-rod string design allowed for removal of pony rods.

The four successful field trials to date have met technical and functional requirements. The space-out/anchor-setting issue experienced in two of the

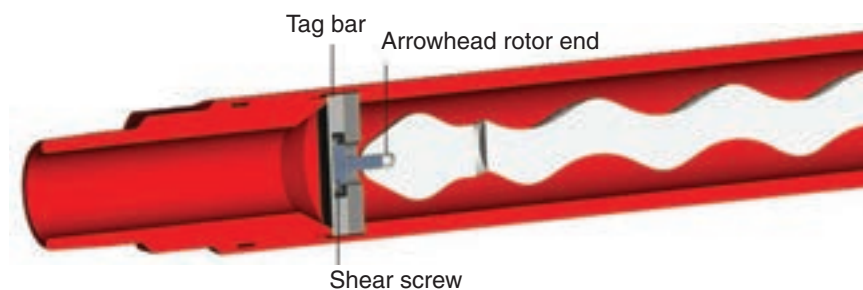


Fig. 3—The patent-pending rotor-lock system will be run in upcoming installations in India and Australia.

trials resulted in development of a rotor-lock mechanism. Reasons for anchor failure include improper installation, improper review of application, introduction into a wrong application, over-torque, and dirty tubing.

Discussion and Next Steps

Changes resulting from testing and field trials include revising the J-slot to confirm that the tool will “J over.” A patent-pending rotor-locking feature was added to the anchor to confirm that the rotor

placement is known when the pump is spaced out (Fig. 3). Pump space-out procedures were developed to provide the option of a flushing operation.

The anchor currently in field trials is now considered a commercial product with a prior review needed to confirm its applicability. Future field trials include installations in India, where four applications introduce the new rotor-lock system, and in Australia. Future development plans include an I-PCP-anchor model for 4 $\frac{1}{2}$ -in. tubing. **JPT**

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Williston Basin Reserves May Top 21 Billion Barrels, Peak Production in 6 to 7 Years

Trent Jacobs, *JPT* Technology Writer

More than 21 billion bbl of light, sweet crude oil will be extracted over the lifetime of the Bakken and Three Forks shale plays, according to the latest projections from energy consultancy group Wood Mackenzie. The two plays are found in the United States' prolific Williston basin and together produce approximately 1 million BOEPD. As production rises from the deeper Three Forks formation, the firm predicts that between 2020 and 2021, production from the Bakken Shale will reach its peak.

Despite the fact that production growth is slowing in the Bakken, Wood Mackenzie said there will be commercial opportunities throughout the basin for years to come. Reductions in drilling and completion costs and increased recovery rates are driving operators to explore less-rich areas of the Bakken. "It might not have made sense in 2010 to spend (USD) 13 million on a Bakken well that is only going to get about 300,000 BOE out of the ground," said Jonathan Garrett, an upstream analyst at Wood Mackenzie who specializes in the Williston basin. "But flash forward to today; now it might make sense to spend (USD) 6 or 7 million on a well to get 300,000 to 350,000 BOE."

Garrett said new technology, better well completion methods, and tighter well spacing will lead to higher overall recovery rates from the two shale plays than previously thought. Last year, the US Geological Survey (USGS) estimated that ultimate production of light, sweet crude from the Williston basin would top out at 7.4 billion bbl. Wood Mackenzie said its reserve estimate was higher because operators will increasingly drill wells closer and closer together, a practice known as down spacing. "We looked at likely and proven operator down-spacing patterns throughout the play, whereas the USGS is of the mind that probably fewer than four wells per spacing unit into the Bakken and Three Forks will be the ultimate development pattern," Garrett said. "We regard that as a bit conservative given the fact that we have seen much more dense projects throughout the Williston basin."

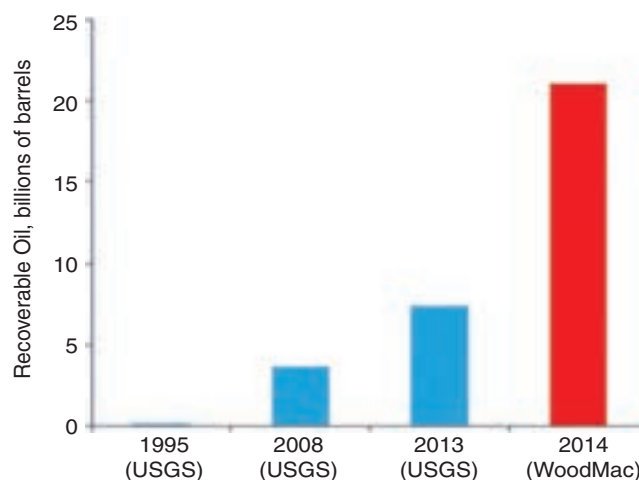


Chart shows a wide margin between Wood Mackenzie's latest reserve estimates and the US Geological Survey estimates for recoverable oil in the Bakken and Three Forks plays in North Dakota's Williston basin. *Graphic courtesy of Wood Mackenzie.*

In areas where the Bakken has been most developed, operators are increasingly turning their attention to the deeper Three Forks shale that is formed of multiple sections known as benches. Production rates from wells drilled into the uppermost bench of the Three Forks has been positive, but less-than-expected production rates from the lower part of the formation has downgraded the play's outlook. Garrett said that because of this, "the footprint for commercial development of the Three Forks will be considerably smaller than previously expected."

"There are pieces of the Bakken that are becoming more interesting," he said. "But we really do think it will be offset by the smaller economic footprint of the lower benches of the Three Forks." **JPT**

US Offshore Regulator to Focus More on Technology

Trent Jacobs, *JPT* Technology Writer

The United States' top offshore regulator said his agency is adopting new policies and measures to improve its working relationship with the offshore industry. To accomplish

this, the director of the Bureau of Safety and Environmental Enforcement (BSEE), Brian Salerno, said that his agency will increase its focus on technology assessment. Salerno

explained that traditionally, BSEE has based regulatory standards in part on industry standards but the ongoing advancements of offshore technology have presented a challenge to this model. “We still rely on that basic approach, but regulations have always had a tough time keeping up with technological change,” said Salerno, who spoke at the Offshore Technology Conference in Houston in May. “For that matter, industry standards are having a tough time keeping up as well. And that has become even more of a problem as the pace of technological innovation and change has accelerated.”

The director said the agency will open a technology center in Houston to work more closely with equipment manufacturers and to study emerging technologies. The technology center will not replace any of the regulatory processes, Salerno said, “but it will add depth and capacity to the bureau, so that as industry continues to innovate and develop new capabilities, we will be keeping pace with you.” BSEE is in the process of choosing a location and assessing staffing requirements and gave no timeline for opening the technology center.

The director also announced BSEE’s establishment of the Ocean Energy Safety Institute (OESI) to serve as a forum for regulators, the industry, and academia to study the role of emerging technology. The inaugural event for the OESI was



Brian Salerno was sworn in as the director of the Bureau of Safety and Environmental Enforcement in August. At the Offshore Technology Conference he spoke about the role of the regulator in regards to new technology.

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held at the University of Houston the week following OTC and focused on the topic of risk management. BSEE is also introducing new language to help clarify the standard of safety it is

seeking from offshore companies and will make accommodations for new technological approaches not covered by existing rules. **JPT**

First Transboundary GOM Leases Awarded Under New Rules

Jack Betz, *JPT* Staff Writer

The US Department of the Interior and the US Bureau of Ocean Energy Management have awarded ExxonMobil three offshore leases in the US-Mexico boundary area of the Gulf of Mexico, the first leases subject to the terms of the 2012 US-Mexico Transboundary Hydrocarbon Agreement.

The agreement governs reservoirs that are split by or close to the boundaries of the US and Mexico. It allows US operators and Mexican state oil company Pemex to explore transboundary reservoirs as single units, encouraging unitization—the process by which multiple leaseholders agree to extract resources through the work of a single operator. Unitization encourages the drilling of fewer wells, which increases efficiency of production and reduces waste as well as the likelihood of environmental accidents, the agencies said. In cases where a

transboundary unitization agreement cannot be reached, parties can each produce as much oil that is calculated to lie on its side of the boundary.

Additionally, the 2012 agreement created a framework allowing each country to regulate activity on its side and inspect the activity of operators on the other side of the boundary. The specifics of this system have not been released.

The ExxonMobil leases sit in the Alaminos Canyon area, about 170 km east of Port Isabel, Texas. The US government estimates that the lease area contains up to 172 million bbl of oil and 304 Bcf of natural gas.

More boundary leases will be up for auction in August. These blocks are located in the Western Gap area of the Gulf of Mexico, north of the continental shelf. **JPT**

Saudi Aramco Progresses on Shale, Confirms Red Sea Find

Abdelghani Henni, *JPT* Middle East Staff Writer

Saudi Aramco has made significant progress developing its shale gas reserves and will begin using shale gas for domestic industrial projects, the company said in its 2013 annual review.

The company said its unconventional gas program became fully operational in 2013, 2 years after it launched a program to develop unconventional gas in the frontier Northern Region, offering new resources for the country's energy needs. Saudi Aramco is now ready to commit shale gas for the development of a 1,000-MW power plant that will feed a massive phosphate mining and manufacturing project. "Saudi Arabia will be among the first countries outside North America to use shale gas for domestic power generation," the company said in the annual review.

Saudi Aramco is also actively exploring for unconventional gas resources in three areas of Saudi Arabia: the northwest, South Ghawar field, and the Rub' al-Khali (Empty Quarter).

"Due to the large scale of these unconventional gas resources and the complexity and intensity of the activity associated with their development, significant investment opportunities and economic benefits lie in the full value chain of this emerging industry," the report said.

In addition to the progress in its shale gas program, Saudi Aramco announced that it discovered three oil fields and two gas fields over the past year. These include the deepwater Al-Haryd field in the Red Sea, which followed a significant gas discovery in the Shaur structure nearby in 2012.

The company said its first deepwater drillstem test operation was successfully executed at Duba-1, located in the northern Red Sea. Tests conducted at a depth of 2,127 ft indicated tight reservoirs for potential future development.

Saudi Aramco increased gas production in 2013 to 11 Bcf/D, from 10.72 billion Bcf/D in 2012. **JPT**

A 3D rendering of a wellbore or pumpjack mechanism. The structure is grey and metallic, with various cylindrical and conical components. Numerous green and yellow droplets of varying sizes are shown within the wellbore, representing fluid flow. A blue rectangular overlay is positioned in the lower-left quadrant of the image.

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Extreme Deepwater Wells Push Drillers to Begin Using Managed-Pressure Methods

Stephen Rassenfoss, *JPT* Emerging Technology Senior Editor



Dual-gradient drilling has long been described as the drilling method of the future for challenging offshore wells. Now there are indications that it could start being used with some regularity, with multiple-well campaigns possible as early as next year.

This method of managed-pressure drilling has been used a handful of times on a floating drilling rig, mostly to precisely manage the pressure in wells while drilling in weak, low-pressure formations prone to major fluid losses. Currently, Chevron and Statoil are seeking to use the system for deep, difficult, high-pressure formations in the US Gulf of Mexico.

A drillship leased by Chevron, *Pacific Santa Ana*, is testing dual-gradient equipment on the ocean bottom while drilling a conventional well, and the company has leased a second drillship from Pacific Drilling, *Pacific Sharav*, that was built to accommodate dual-gradient drilling equipment.

Statoil is seeking a permit to drill what could be the first dual-gradient well in the deep waters of the Gulf of Mexico, using another version of the managed-pressure method. "When we came here to the Gulf of Mexico, it was a perfect match with the challenges we had here," said Uno Holm Rognli, vice president of drilling and wells in the offshore US for Statoil. "We started a program locally to develop this system" for conditions in the Gulf.

It is the next step for the method used by Statoil off Norway, and by three companies in water 7,500 ft deep off Cuba. In both places it was used to successfully drill wells where pressure was so low, and the rock so fragile, that wells drilled using conventional methods were plagued by major fluid losses.

While a few pioneers are working on dual-gradient drilling, there is a broader, growing base of operators using managed-pressure systems offshore. These are closed-loop systems with metering to allow precise measurement of change in fluid flows and chokes that allow them to apply backpressure when needed.

Petronas and Petrobras are embracing managed-pressure drilling to deal with offshore wells where total fluid loss makes some wells impossible to drill using conventional methods. Managed-pressure equipment allows them to drill through sections of wells with cavernous underground hazards that can cause major fluid loss by using managed-pressure methods such as mud-cap drilling.

The modified riser joint used for a well drilled by Petronas to attach a pump to drill a dual-gradient well offshore Cuba, allowing it to drill in a low pressure carbonate formation where major fluid losses had been a serious problem. *Courtesy of Petronas.*

The Brazilian oil company has adapted it for deepwater drilling and plans to equip 16 drilling rigs to be able to do it by 2016.

"Managed-pressure drilling is a key technology to help us put into production some of our vast offshore projects," said Jose Umberto Arnaud Borges, offshore well project manager exploratory well construction at Petrobras. The rigs are equipped to precisely control downhole pressure within limits that would be too tight to drill using conventional methods.

Dual-gradient drilling is a variation of managed-pressure drilling created to widen those constricted drilling windows by eliminating or reducing the impact of the tall column of fluid returning up the riser. Dual gradient was chosen by Statoil, which is considering using other managed pressure methods, because it allows the company to better handle problems on difficult wells such as lost circulation, hole instability, and fluid influxes, said John-Morten Godhavn managed-pressure drilling specialist at Statoil Gulf of Mexico. "We need better control of the bottomhole pressure and a better kick detection to manage it better," he said.

The deepwater Gulf could represent a high-profile test site for dual-gradient technology that has been quietly nurtured by a small community of experts whose careers have been intertwined with dual gradient since the late 1990s. That was a time of intense interest in the technology, with ideas ranging from using gas injections to hollow glass balls to reduce the weight of the fluid rising in extended risers.

Chevron is using a method successfully tested in 2001, but as with most dual-gradient methods, it was set aside for years as drillers used other methods to deal with challenges the technique was created to address. Chevron picked it up



The subsea pump used to drill a difficult well offshore Cuba was developed by Enhanced Drilling. *Courtesy of Petronas.*

NEW DRILLING METHODS ADD TO TROLL'S LIFE SPAN

The Troll field is one of the largest gas producers discovered off Norway, but ensuring its long-term future required finding ways to drill wells in an increasingly fragile formation to develop its rich oil reserves. Production dating back to 1995 has sharply lowered formation pressure and caused subsidence, making it difficult to drill the wells Statoil needed.

Even with some of the lightest drilling mud, Statoil was unable to blend a drilling fluid light enough to avoid major losses in some parts of the formation, said Dag Ove Molde, project leader of dual gradient on Troll at Statoil, the operator of the field.

Drilling is expected to get even more difficult as future production further reduces reservoir pressure. A Statoil study predicted it would need to curtail drilling by 2018 because it will become increasingly difficult to drill long horizontal wells needed to efficiently produce oil reserves.

With current methods at its limits, Statoil turned to dual-gradient drilling. The approach called EC-Drill placed a pump on a modified joint in a riser where it could pump the drilling fluid out of the riser and into a flexible pipe to the surface. This lowered the pressure in the well by leaving about two-thirds of the riser filled with air much of the time. The bottomhole pressure using EC-Drill was significantly less than what it would

have been when drilling with a full riser in water 1,000 ft deep. This allowed drillers at Troll to remain well below fracture level, Molde said, adding, "It enabled us to reach targets that we were not able to reach with conventional technology."

The technique allowed Statoil to significantly lower the effective mud weight while drilling three laterals. It reported reducing total mud consumption by about 70% compared with conventionally drilled wells. By measuring the volume of fluid flowing through the subsea pump and comparing that total to the volume flowing into the well, it was possible to quickly detect small losses and react to them by varying the pump speed.

Speeding the pump reduced the fluid level, reducing the pressure of the mud returns by lowering the equivalent circulating density—the pressure added by the friction as fluid is pumped through the well. Molde said dual gradient could allow drilling for another 10 to 15 years and eliminate fracturing while drilling.

In May, the EC-Drill equipment was out for servicing, but Molde expected to use it again. "We will drill one well conventionally and, hopefully, then we will go back to dual gradient for future wells," he said. "The more wells we can drill with this technology, the better."



The EC-Drill pump is connected to the riser in the moonpool of the COSL Innovator which was used to drill wells using the dual-gradient system in the Troll field off Norway. In the bottom of the metal frame are the pumps and in the lower middle is a motor. *Courtesy of Enhanced Drilling.*



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DUAL-GRADIENT DRILLING

again around 2009 and decided to build a full-scale version of the method developed by the SubSea Mudlift Drilling Joint Industry Project.

Ready Now?

Many of the key players in this community were on a panel of 10 at the recent Offshore Technology Conference in Houston discussing: *Is Dual Gradient Ready for Prime Time?* The answer offered by the panel was that increased use of dual gradient is inevitable based on the drilling challenges presented by many of the best available prospects, but adoption could be gradual.

"We started back 15 years ago. It is a long transition but I think we are close," said John Kozicz, technology manager at Transocean. "We are entering an era with more managed-pressure drilling and [the industry] will have to take the next step and that will be dual gradient."

Roger Stave, senior technology adviser at Enhanced Drilling, formerly part of AGR Group, said he has discussed multi-well drilling campaigns using its EC-Drill method with several operators.

Shell is also considering whether to use some form of dual gradient. At the panel discussion, Brian Tarr, a principal deepwater engineer at Shell, said he sees widespread future use though that may well be after many of its long-time supporters have retired. "It will take 10-25 years before the industry makes full use of dual gradient," Tarr said. "The ones who do it, they love it and do not want to go back. But that first well is hard."

In the short term, managed-pressure methods used offshore are likely to be similar to the ones used

by many wells onshore. Based on equipment rentals, drillers in the US Gulf of Mexico are quietly adding equipment for better detection of kicks—influxes of fluids and gases that could lead to a blowout—and better managing downhole pressure using basic managed-pressure installations, said Don Hannegan, strategic manager for drilling hazard mitigation technology development at Weatherford.

This transition is not like switching on a light bulb. He compared the rate of change to using a dimmer switch to gradually increase a bulb's brightness. He said 40% of US land drilling programs are using a basic closed-loop, managed-pressure drilling system today. By basic, he means a rotating control device (RCD) is used to divert fluid beneath the rig floor to a drilling choke, which allows the operator to apply backpressure, when needed, for well control. "I believe that within 10 years, 40% of offshore [shallow and deepwater] drilling programs will be, as land programs are today, drilling with a RCD and a dedicated choke manifold of some type," he said.

One motivation for this is the need to find more accurate measures of fluid flow increases from wells to detect kicks. Measuring the level of fluids on a platform bobbing in the ocean comes with an error rate of 20 bbl or more. Managed-pressure drilling systems can detect far smaller variations, and the US offshore regulator, the Bureau of Safety and Environmental Enforcement (BSEE), is seeking improvements. "BSEE considers it very important to be able to accurately measure the mud return flow rate, which is critical in early kick detection, and is working with industry on technologies that will aid in this area," said Lance Labiche, chief of BSEE district operations support for the Gulf of Mexico Outer Continental Shelf Region.

Backers of dual gradient said there is a limit to the problems that can be solved using the managed-pressure approaches used on land where there is no riser to contend with. Based on the attendance at industry meetings on dual gradient, there is growing interest in this approach. But as with many innovative ideas, there are few early adopters.

While Hannegan sees the potential benefits of full dual gradient with a mud pump located on the bottom, he asked, "How many deepwater rigs will be capable of doing that within the next decade, or are operators willing to pay for it?"

The cost of full dual gradient looks high until it is compared with the staggering expenses associated with developing deepwater fields where drilling costs commonly hit USD 1 million per day and a production well costing USD 200 million does not stand out.

To Robert Ziegler, head of wells and production technology for Petronas, the added cost of using dual-gradient hardware could be covered by being able to drill a series of difficult wells on time, with a hole that allows

To win approval to drill using a dual gradient in the US Gulf of Mexico, operators will need to satisfy regulators as the Bureau of Safety and Environmental Enforcement in four areas:

- ▶ Training
- ▶ Well control
- ▶ Management of change
- ▶ Equipment reliability

BSEE personnel will be present as operators try to win approval to use dual-gradient drilling. Regulators will:

- ▶ Participate in the operators hazard identification and operations analysis process (HAZID/HAZOP).
- ▶ Attend classroom training for rig personnel.
- ▶ Witness offshore equipment testing before it is used for drilling a live well.
- ▶ Ensure all testing criteria are satisfied before it is used.

Source: BSEE

MANAGED-PRESSURE DRILLING MIGRATES INTO DEEP WATER OFFSHORE BRAZIL

Two years ago, as drillers approached the bottom of a deepwater well in the Lula field, they were stopped again and again by total drilling fluid losses. After a series of frustrating efforts to finish the well, drilling had proceeded only 27 m and it was obvious the hole needed to be plugged and temporarily abandoned.

It was one of a worrisome subset of wells in the Brazil's rich subsalt trend plagued by high costs, delays, and safety concerns. Conventional drilling methods could not navigate the tight pressure limits in these rich but difficult formations. Rather than limiting drilling in locations with reservoirs that get thousands of feet thick, Brazil's national oil company Petrobras began looking for a better way to deal with this significant minority of troublesome wells, said Jose Umberto Arnaud Borges, offshore well project manager of exploratory well construction at Petrobras.

The company concluded that managed-pressure drilling would be a key technology. It was needed to drill in formations demanding extremely tight pressure control. In some, the safe drilling margin was so narrow that the effective mud weight would need to remain within 0.4 lb/gal, he said. Pressure management in the pre-salt is complicated by the added weight of the fluid in a tall riser, often more than 6,500 ft long. Adding to the hazards are fractures and cavernous features, such as karsts, that could lead to severe fluid losses if the pressure moved outside that narrow window.

"Both geological environments—narrow drilling margins in HP/HT [high-pressure/high-temperature] wells and severe or total lost circulation—require the use of managed-pressure drilling for mud-cap drilling and safe drilling of these intervals," said Humberto de Oliveira Maia Neto, who headed this effort as the leader of the Offshore Exploration Drilling Group at Petrobras.

Applying managed-pressuring drilling required adapting a method commonly used on land, and sometimes offshore, but never in water so deep. "We found that there was nothing developed for floating rigs," Borges said. That led to a couple years of work to adopt the available tools to floating rigs, where the motion of the sea complicates the task of measuring and controlling fluid flow. Petrobras had to develop new procedures for deepwater managed-pressure drilling and train its crews.

Petrobras now has two drilling rigs working offshore Brazil equipped to do managed-pressure drilling, and plans to expand this total to 12 by the end of next year and to 16 by 2016. So far, managed-pressure drilling has been used on seven wells, including the one left unfinished in the Lula field.

"We re-entered the same well using managed-pressure drilling and were able to drill 89m with minor [fluid] losses. Then we started to get full losses, with no circulation at all," Borges said. At that point, the crew turned to another form of managed-pressure drilling: pressurized mud-cap drilling.

This approach, which was developed on land and used in shallower water, reverses the normal order for fluid flow in a well. Fluid with a heavy mud weight is pumped down the riser annular into the well and held in place by the closed choke on



The Ocean Valor, owned by Brasdril, is one of two rigs equipped by Petrobras for managed-pressure drilling in deep water. It was used to finish a well in the Lula field that could not be completed using conventional methods. *Courtesy of Petrobras.*

the managed-pressure system. The mud creates a barrier to control the well while drilling continues using a lighter fluid, commonly seawater. The water, cuttings, and some of the mud flow into the openings in the formation. "We drilled another 70 m and were able to cover the complete reservoir zone," Borges said. "It was a very successful operation."

While Petrobras' initial focus is on dealing with wells in spots likely to cause trouble, its expansion plans see managed pressure as a money saver in wells that could be drilled conventionally but can be done better and more efficiently using managed-pressure drilling.

The company projects the total average cost of drilling a well using a drilling rig equipped for managed-pressure drilling is USD 19 million, but it expects that will reduce other expenses by USD 25 million, for a net saving averaging USD 6 million per well, Borges said.

Savings come in the form of reduced time lost to deal with pressure management problems, such as lost circulation, savings on drilling mud, and avoiding well-design contingencies, such as adding casing strings to deal with unexpectedly difficult well sections.

Expanding its managed-pressure fleet will require installations costing about USD 17 million per vessel as well as training crews how to drill differently. "They are used to doing it a certain way for decades and we are saying, 'OK, now learn how to do this a different way,'" Borges said, adding, "We are getting more and more confident with our methodology and our people."

DUAL-GRADIENT DRILLING

greater long-term production. "Time is everything and hardware is nothing in this world," Ziegler said.

Cautious Steps

Based on that timetable, the adoption rate for dual gradient will be gradual, even compared with the unhurried pace commonly seen for new technology adoption in exploration and production. When Ken Smith, project manager of dual-gradient drilling implementation at Chevron, describes the future of the technology, he sees dual gradient as inevitable for deepwater drilling, but does not talk about timetables.

Regarding the dual-gradient equipment his company has been using in tests, he said it "has been performing well, and we remain extremely optimistic." But he also cautioned that the company is working through a long list of tests to identify problems that need to be addressed. Those are being done while Chevron's dual-gradient-equipped drillship continues to drill using conventional methods.

Many expect adoption of dual gradient to rise because conventional drilling has its limits. As the industry moves into places of deeper water and more extreme wells—the second dual-gradient-ready ship leased by Chevron is designed to drill a well down 40,000 ft in water 12,000 ft deep—the need grows for better ways to manage pressures while drilling.

During the OTC panel discussion, Smith said the industry is getting "closer to the wall" of what can be profitably drilled using current methods. Advances in drilling fluids, reamers, and expandable casing have allowed drilling in increasingly difficult formations, but "we are getting pretty close to the limits" of what can be done without dual gradient, he said.

"In the Gulf of Mexico, we are drilling some of the most technically challenging wells in the world. It is tough to get them down," he said. Wells that were supposed to take 6 months to complete took 9 months. "It is not hard to do the math on what a 9-month well costs," Smith said. Even worse, some wells are so difficult they are abandoned.

As the water gets deeper, it gets harder to drill wells because the difference between the pressure needed to control the well, and the amount that will fracture it, shrinks. "This is complicated by the fact that the friction pressures associated with circulating high-density drilling fluid up a small wellbore from 30,000 ft are tremendous. It simply gets worse with depth," Smith said.

Chevron is seeking to widen the margin by moving the mud pump near the wellhead, expanding the window to what it would be on land, and also precisely measuring and managing pressure levels to stay within the limits. The rewards for full dual gradient include expanding the number of wells that can be safely drilled, reducing the number of delays, and, possibly, well plans resulting in larger, more productive holes.

Full or Partial

Chevron and Statoil are using different versions of dual gradient and have different goals in mind. The variety used by Chevron requires the largest commitment, starting with a drillship equipped to handle three large seawater pumps to drive a subsea pump capable of lifting the drilling fluid from the well up as much as 10,000 ft through a 6-in. pipe. The reward for bypassing the riser, which is filled with seawater-weight fluid during drilling, is the ability to use heavier mud and better control the pressure it exerts on the formation.

That is expected to allow well designs such as those found on land, which would sharply reduce the number of casing strings, allowing a larger hole at the bottom. A few added inches of diameter could be extremely valuable. Tight holes through a reservoir make it more difficult to do completions that maximize early production.

Statoil's approach is less costly, as are the stated benefits. The EC-Drill places a pump on a joint in the riser that allows drilling fluid to be pumped out and sent up a line. The fluid level in the riser can be moved up and down by varying the pump speed that controls the bottomhole pressure by varying the pressure gradient in the riser. Tracking changes in the pump speed and the fluid level in the riser allows it to detect small variations in fluid flows.

But unlike Chevron's system, where the pump is located above the subsea blowout preventer, its pump is located about 1,000 ft below the surface. The Norwegian oil company's goal is to drill wells that could be drilled conventionally, but do it more efficiently.

"This system reduces our nonproductive time," said Rognli of Statoil. "It will reduce the risks and the contingencies. Maybe today we have one or two contingency liners in the well plan."

There is a significant reward for drilling wells according to plan. A six-well survey of recently drilled deepwater wells in the Gulf of Mexico found that the average one ran 20 days longer than planned, according to a recent paper presented by Morten Godhavn at OTC.

The Statoil system has a smaller footprint than the Chevron system and requires far less rig modification. "There is a much lower investment cost than with a full-blown dual gradient system," said Odd Helge Inderhaug, leader of drilling and well technology in research, development, and innovation at Statoil. "One of the main advantages is the simplicity of it. It is a totally different level of complexity."

"Chevron has talked about saving casing strings. We do not mention that. It may save casing strings but that is not the goal," he said.

Every Time

Statoil appears to be the company likely to drill the first dual-gradient well in the Gulf of Mexico. It has applied for a permit with the BSEE, and Rognli is hopeful the regulatory body will



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DUAL-GRADIENT DRILLING

DRILLING A DIFFICULT WELL IN DEEP WATER OFF CUBA

The list of wells drilled using dual gradient includes one drilled in the “eastern Gulf of Mexico,” which could be more precisely described as offshore Cuba.

From a drilling standpoint, the well stands out as the only one using dual-gradient drilling done in water so deep, at 7,500 ft, and it was completed on time by Petronas in a formation where conventional methods had failed, said Robert Ziegler, head of deepwater drilling technology at the Malaysian national oil company.

The well offered a difficult test for a joint industry project that paid much of the cost of the well managed by Petronas. The company is one of the most active users of managed-pressure drilling methods offshore, with as many as five rigs using the technique in southeast Asian waters, but it never required dual gradient in that part of the world.

Petronas chose a form of dual gradient drilling known as EC-Drill because it was suited for working in a low-pressure formation, where tight pressure control was needed to avoid formation damage and fluid loss. The system reduced the pressure exerted by the fluid returning up the riser by using a pump connected to the riser about 1,000 ft below the drilling rig. By adjusting the pump speed, it could quickly change the bottomhole pressure. Sensors in the riser allowed drillers to track those changes as they occurred.

Speeding the pump lowers the fluid column and reduces effective pressure; slowing it can raise the column and the

pressure. Either change can be made in minutes. Making a similar change by adding drilling mud would take hours to circulate throughout the well, Ziegler said.

While drilling, Ziegler said the crew observed that changing the pump rate could affect drilling performance. Increasing the pressure significantly slowed drilling, while decreasing the pressure speeded penetration equally, he said.

One question facing the EC-Drill method has been: Will natural gas escape from the drilling mud and accumulate in the open space inside the riser? The answer on that well was “no gas was recorded in the top of the riser at any stage during the operation,” according to an SPE paper.

During cementing, the managed-pressure control systems allowed a pressure reduction that made it easier to get the mud to rise to the planned height, Ziegler said.

The EC-Drill equipment was installed for the job using a 2-month trip by the semisubmersible rig, Saipam’s *Scarabeo-9*, from Singapore to the Gulf of Mexico. It successfully drilled three wells at the prospect, said Roger Stave, senior technology adviser at Enhanced Drilling, which provided the drilling equipment.

“We were able to reach TD [total depth], thanks to the system’s ability to remove the weight that would have been added by the weight of a fluid in the riser in a weak formation,” Ziegler said. “There were no well control incidents and no lost circulation in a place where others were fighting losses.”



The containers hold equipment and controls used for dual-gradient drilling off of Cuba by Petronas. *Courtesy of Petronas.*

approve it. "We are in close dialog with the BSEE. We have been presenting it with information and updates," he said. "They are on top of the technical challenges and understand them. They have said they do not see any showstoppers."

Labiche of BSEE said he could not speak to any issues related to reviews of dual-gradient technology or applications for permits to use dual gradient in the Gulf of Mexico.

Smith said Chevron is also working with BSEE officials to answer their questions. "This is the second well we have done testing on. We are still demonstrating the equipment and viability of our operating procedures," he said. "Once we get comfortable with that, and more importantly the BSEE does, then we can get permission to drill a well." Since a drillship normally drills a couple of wells a year, the initial use could slip into next year.

US regulators have recognized the problems created by shrinking drilling margins and the potential

benefits of dual gradient. A 2011 US government backed study posted on the BSEE website said dual gradient can be "safe or safer" than traditional methods. A presentation by Labiche underlined the limits of conventional drilling methods, examining a growing number of deepwater wells drilled over the past decade in which drilling margins are at the minimum safe limit set by the agency. But he said operators need to make a case that they can deliver on the promise of dual gradient. He offered a check list of issues that need to be addressed to ensure the system can safely drill in the difficult conditions of the Gulf of Mexico.

"The top concerns are effective training and well control," he said. "In the environment we are operating in, it will only take one mistake using this equipment and it will affect everyone in deep water, and prevent dual gradient from being the game changer it can be." JPT



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New Ways To Manage Pressure Raise Well Control Questions

When discussing dual-gradient drilling, there is an important distinction between controlling wells and well control.

Controlling wells requires maintaining the balance between preventing influxes that could lead to trouble and exceeding the limit that could push drilling fluids out of the well and into the formation. Well control refers to the hardware, procedures, and training associated with dealing with situations in which an influx has occurred and needs to be quickly stopped before it grows into a bigger problem, and then circulated out of the well.

For companies seeking to win approval from the US Bureau of Safety and Environmental Enforcement (BSEE) to drill the first deepwater well in the US Gulf of Mexico using dual-gradient drilling, questions about well control are critical. Offshore regulators want to be sure that all the new equipment has been thoroughly tested because this is a new way to drill, and the BSEE wants to be sure that it is understood that when it comes to well control, the requirements are not changing.

Chevron and Statoil have been working through a detailed testing program to identify and remedy any potential problems, and they have prepared their crews to safely operate the system and properly respond to any situation.

“The challenge we see at BSEE is that training is huge. It is a whole new way of looking at and thinking about” drilling, said Lance Labiche, chief of BSEE district operations support for the Gulf of Mexico Outer Continental Shelf Region. “When it comes to well control, there are some significant changes with certain systems.”

The dual-gradient designs may improve well control. Flow-measurement capabilities in these closed systems are able to offer earlier warnings than traditional systems as well as quicker ways to apply pressure downhole to stanch an influx. But drillers have had to learn to distinguish between an early warning and normal variations in fluid volumes.

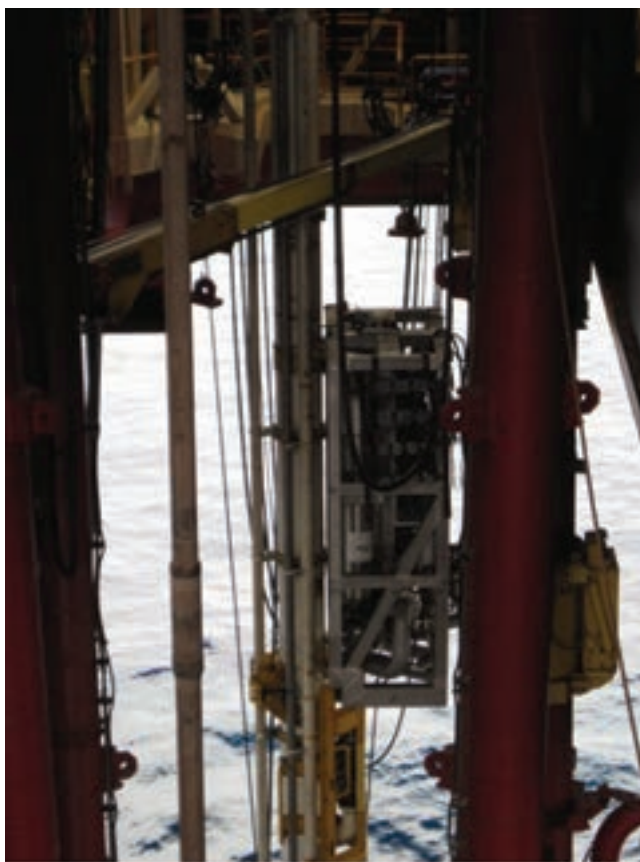
Chevron’s full dual-gradient method should allow heavier mud weights below the seabed, creating a fluid able to halt a well from flowing after the pumps go off, even if the drilling rig is accidentally disconnected from the well.

At that point, the meaning of the phrase restoring full riser margin becomes apparent. The mud column from seabed to bottom of the well has sufficient density of its own to prevent the well from flowing, serving as an effective

primary well control barrier. In a conventional well, the mud weight used must be lighter to allow for the added pressure from the riser.

Statoil is adding flow controls to the EC-Drill system that it plans to use to drill the first deepwater well in a high-pressure environment in the Gulf of Mexico. It has added a unit with two shutoff valves, which can be used during pipe connections to maintain the pressure without having to fill the riser to increase pressure, and a second able to close quicker than a BOP in case a rig pump fails, halting circulation and causing an abrupt pressure drop.

Both valves would block the annular space between the drillpipe and the casing. Their role sounds similar to the job of the annular rams in a BOP. But Statoil officials emphasize



A mid-riser pump used to drill a dual-gradient well off of Cuba is lowered into the water to about 1,000 ft below the surface.

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Dual-Gradient Drilling is: “Two or more pressure gradients within selected well sections to manage the well pressure profile.”

Conventionally, the Primary Well Barrier is a “single gradient” mud from wellbore to “bell nipple” and this drilling mud exerts a pressure on the formation that is above pore pressure. In “dual gradient” the fluid column is not “uniform”; the fluid column has “two or more” different densities. So, if one is air or gas as in EC-Drill, the mud weight must be heavier if the pressure at the bottom shall be the same. Thereby the “pressure gradient” is altered. Similarly, seawater in the riser is typically much lighter than the drilling mud used in deep water.

Roger Stave

these quicker-moving closing devices are not elements of the well control system.

Well control is done by the BOP, which must be closed when there is an indication of a kick. No party seeking to drill using dual gradient in the Gulf of Mexico is saying otherwise. It is a critical point because US regulators make it clear they do not want accumulations of hydrocarbons, particularly natural gas, in the riser. The limit is no more than the small volumes that can flow into the well when pumps are shut off briefly for operations, such as connecting pipes.

When asked during the panel discussion at the Offshore Technology Conference (OTC) if that rule might change if managed-pressure systems were added offshore, Labiche of BSEE said, “We do not see that changing any time soon. As long as we are using a traditional drilling riser, we do not want gas in the riser.”

If gas does appear, standard operating procedures apply. Those include closing off the riser using the annular rams in the BOP, adding mud to increase the pressure and stop the influx, and bleeding off any gas through the choke line.

Managing Differently

The question about gas in risers was raised because the capabilities of managed-pressure systems have inspired some users to reconsider the common wisdom on how to deal with an influx from the formation. They can detect changes in fluid volume of 1 bbl or less, which would never be observed using a conventional system measuring fluid returns on the tanks on a floating rig.

In Brazil, Petrobras has agreed with regulators that when an influx exceeds 2 bbl, it will begin using traditional well control procedures on its deepwater rigs with managed-

pressure drilling, said Jose Umberto Arnaud Borges, offshore well project manager exploratory well construction at Petrobras.

An influx would typically need to be about 10 times that large before it would be apparent to crew members on a platform using a system measuring fluid levels in a return tank on a rig in active seas, said Don Hannegan, a strategic manager in drilling hazard mitigation technology development at Weatherford.

The increased awareness of small changes, and the ability to quickly apply backpressure to stop them, is leading some to say there is a better way to react to what managed pressure industry standards refer to as flow anomalies. One of the most vigorous advocates for change is Robert Ziegler, who is head of deepwater drilling technology at Petronas, one of the most active managed-pressure drilling users offshore. The company also drilled a dual-gradient well in deep water, and used its pressure-management capabilities while cementing the casing.

Ziegler advocates using quick detection of relatively small volume influxes. He advocates using the managed-pressure system to quickly add backpressure to stop the influx, and then circulating hydrocarbons from the influx out normally using the separator that removes oil and gas from drilling mud.

This method breaks from the standard procedure for reacting to kicks, which is to shut down the mud pumps to stop the fluid from moving, and then shutting the annulars in the BOP. While that does keep the influx in place, when fluid stops moving the pressure it exerts on the formation drops because it loses the force exerted by friction as it rises in the hole—the equivalent circulation density—at a moment when greater pressure is needed. This reduction of several hundred psi increases the flow rate, he said.

Shutting in the BOP will eventually increase the pressure and stop the inflow, but it takes nearly a minute to close the annular rams in conventional systems, which are not good at accurately detecting small influxes. The initial loss of pressure when the pumps are shut down can allow an influx to grow significantly. “A 5-bbl kick turns into a 60-bbl kick,” Ziegler said, adding that the current standard procedure “is the worst thing you can do” if you need to minimize an influx. He adds that when the fluid stops flowing, it allows gas to be concentrated in a small area, rather than being spread out over a longer distance in a low-density stream that can be removed using standard processing.

The approach is in line with the managed-pressure guidelines from the International Association of Drilling Contractors, Ziegler said. But as managed-pressure systems move into deep water drilling they are undergoing scrutiny.

One of the presentations at OTC discussed the value of using “dynamic control,” which uses managed-pressure

hardware to quickly detect and limit an influx and then flow it out at a pace that allows any hydrocarbons to be safely removed. "The benefits added by managed-pressure drilling are not fully understood," said Oscar Gabaldon, operations manager at Blade Energy Partners who presented the paper. "With small influxes it is safer to circulate them out."

Based on Ziegler's research and experience with offshore managed-pressure drilling, an influx from a deepwater well rises slowly through drill mud, if it rises at all, and disperses as it does, making it easier to manage using available equipment.

Operators are researching whether well control should be handled differently using managed-pressure equipment. A recent joint industry project (JIP)—The Controlled Mud Pressure JIP—investigated the ability of the EC-Drill systems to detect small kicks, and also observed how simulated kicks using nitrogen move up a riser, said Roger Stave, senior technology adviser at Enhanced Drilling.

Results are not final, but Stave said the system did show the system could detect influxes of less than a barrel in 10 to 20 seconds. In contrast, in a conventional well, he said it can take several minutes to detect, and only be noticed when there is an increase of 20 bbl or more of fluid in the fluid return tanks.

Given the ability of managed-pressure systems to quickly detect and act on influxes too small to be observed in conventional systems, Stave sees merit in Ziegler's call for a change in thinking on circulating out kicks. But he recognizes this will take time. "Everyone wants to take it a step at a time and become comfortable where they are," he said.

US offshore regulators have asked the industry to improve its ability to detect influxes of fluids and gases, which may provide an early warning of a kick that can become a blowout.

The hardware used to manage pressure could be added to help address this concern, said Hannegan of Weatherford. He was involved in developing a kick-detection system that can be quickly installed with minimal rig modification. It would divert fluid returns using a rotating control device within the marine diverter, measured with a Coriolis meter, and the measurements would be adjusted to remove the rising and falling of the sea on a floating rig. That total, when compared with the volume of fluid flowing into the well, could detect relatively small influxes that may be a kick.

"My opinion, based on bits and pieces here and there, is that probably by next year BSEE will be encouraging operators, as they issue permits to drill, to show what form of early kick-loss detection they are using," he said. **JPT**

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With Dual-Gradient Drilling, the Name Requires Explanation

Dual-gradient drilling covers a variety of methods for managing pressure within an offshore well while drilling. Dual refers to systems built to reduce or eliminate the pressure added by drilling fluid in the riser. The goal is to create distinct pressure gradients above and below the mudline.

It is a departure from the simpler traditional approach using a single fluid combining water or oil plus drilling mud to make it viscous enough to remove cuttings while drilling, and just heavy enough to control pressures in the open hole without causing damage.

As drilling moved into deeper waters the gap has narrowed between the effective mud weight-per-gallon to offset the formation pressure, and the level that can fracture it. Drillers refer to this slim margin as working within tight drilling windows.

Drilling on a platform floating in deep water magnifies the difficulties of precisely managing the pressure in wells drilled through unpredictable, sometimes weak rock. The seemingly simple goal of, for example, creating a fluid with a mud weight of 13.5 lb/gal is complicated by long return trips to the drilling rigs that include risers that can be a mile or more long. There are two factors at work:

- ▶ The long riser adds to the pressure exerted on fluid in the well. Drillers adjust by using fluids with a lower mud weight to ensure the force it exerts is within the drilling window.
- ▶ The friction encountered as the fluid returns up the annulus adds to the pressure the formation “sees” while it is moving, which is known as the equivalent circulating density (ECD).

To demonstrate the effect of increasing water depth, Ken Smith, manager dual-gradient drilling implementation at Chevron, presented a slide showing how the drilling window would narrow if a field was moved into deeper water.

A study cited by Lance Labiche, chief of district operations support section for the US Bureau of Safety and Environmental Enforcement’s Gulf of Mexico Outer Continental Shelf Region, showed that about 400 wells drilled over the last 10 years in the Gulf of Mexico had a drilling window of 0.5 lb/gal, which the agency has set as its minimum safe margin.

“While it is safe to drill these wells with a 0.5 ppg drilling margin, they are nearing the limits of being drillable

using conventional drilling practices,” Labiche said. “Dual-gradient drilling has the potential of helping manage the problem of tighter drilling margins as we move to deeper water and drill through more depleted sands.”

Casing Limits

Narrow drilling margins lead narrowing holes. Complex casing designs are a tangible indication of the many problems encountered drilling in formations where tight drilling windows are combined with other challenges, ranging from fractured carbonates to unexpected changes in pressures that can cause a kick, which is an influx into an open hole that must be controlled to ensure it does not grow into a blowout.

Adding sections of casing stabilizes the hole, but there is a downside. Each string of casing is narrower than the previous one so it can be moved into place. In deepwater wells the tight pressure margins require many strings to be set, with 10 or more in some cases.

Drillers have worked to minimize the problem by using techniques to strengthen the borehole or limit narrowing with expandable casing, but there is a limit to the relief those can offer. Managing pressure while drilling at depths where the pore pressure in the rock can change unexpectedly is like moving a piano through a tight passage on a bobbing ship. It

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DUAL-GRADIENT DRILLING

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Deepwater
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Difficult formations in the deepwater US Gulf of Mexico had led to complex well designs, with many strings of casing added to create holes that are costly to do and often are narrow at the bottom, limiting production. *Courtesy of Chevron.*

is hard to avoid bumping into limits, and when that happens the damage can be lasting.

"The formation will see big pressure and small pressure. All those fluctuations stress formations," said Uno Holm Rognli, vice president of drilling and wells offshore US at Statoil.

Full or Partial

Dual-gradient systems attack the problems peculiar to these wells in a variety of ways. The differences reflect the multiple

factors determining the pressure exerted by the drilling fluid and design tradeoffs reflecting the cost and complexity of these approaches.

The version known as full dual gradient moves an enormous mud pump to the seafloor. Drilling fluid and cuttings are removed from the riser after the blowout preventer and lifted up in a 6-in. pipe to the drillship.

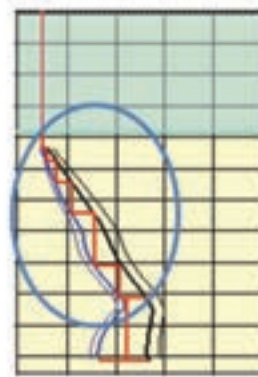
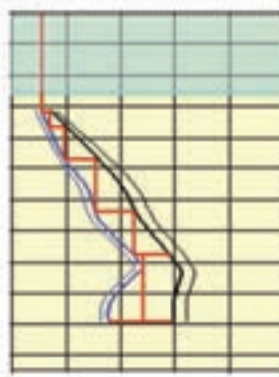
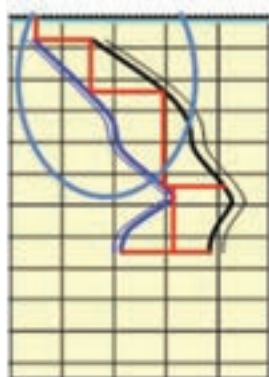
A barrier separating the well from the riser during dual-gradient drilling, allows the annular above the mudline, normally used for fluid returns, to be filled with a seawater-weight fluid. Removing the weight of the riser, and managing the pump speed, widens the drilling window, and allows heavier weight fluid.

"The bottomhole pressure is the same—dual gradient or conventional—but denser mud is used which is much more in harmony with nature," Smith said. "You remove the problem of water depth."

The second dual gradient approach now in use also uses a pump to lighten the riser, but it is located on the riser about 1,000 ft below the surface. Normally there is air in the riser above the fluid level, which is adjusted up and down to manage the downhole pressure.

For Statoil, the biggest backer of what is known as a mid-riser system, the appeal of the pump is its ability to quickly adjust the pressure in the well by raising and lowering the fluid column using the pump. Speeding the pumping rate lowers the fluid level and the pressure in the well, slowing it allows the column of fluid to rise, increasing the effective pressure.

Deeper Water Means Tighter Drilling Window



Water depth, ft	200	2,500	5,000	7,000
Effective Mud Weight lb/gal	14	13.5	12.8	12.4

This illustration shows how the drilling window—the difference between the effective mud weight needed to offset the pore pressure for well control (blue line) and the level where it will fracture the rock. These illustrate drilling a wellbore 14,800 ft deep into the same formation. *Courtesy of Chevron.*

There is a direct correlation between pressure changes measured by sensors in the riser and in the bottomhole pressure, said Roger Stave, a senior technology adviser at Enhanced Drilling, which was formerly part of AGR Group.

It is called the EC-Drill system, which refers to how changing pump speeds can vary the effective pressure by changing the ECD. This adjustment can be made in minutes, a fraction of the time needed to reach the same goal by adding mud and waiting for it to circulate through a well, Rognli said.

The Chevron system also can alter the pressure by changing pump speeds, and can do so faster than the EC-Drill system. Both systems can be programmed to manage fluid flows using real-time information.

Orphan Technologies

The dual-gradient evolutionary tree includes branches that stopped growing years ago. Some appear dead, such as adding hollow glass balls to lighten fluids in the drilling riser, while others could be resuscitated with support from a backer, such as reducing the weight of the fluid in the riser by pumping in a lighter liquid into the riser.

Transocean developed that idea as a way around one of the big obstacles to dual gradient—the large amount of equipment and installation time required by some approaches. “One roadblock has been finding a practical dual-gradient method using available rigs without enormous modification,” said John Kozicz, technology manager at Transocean. The company’s goal was to create a relatively simple system that could be installed in 3 to 4 weeks.

The system pumped a lighter fluid into the fluid as it rose within the riser, and then directed it through a separator that removed it for reuse. The benefit was it could significantly reduce the impact of the riser on drilling margins, he said.

It was built and installed on a drillship, *Discoverer Enterprise* in 2009, but before it was ever used disaster struck. The vessel was pressed into service after the destruction of Transocean’s *Deepwater Horizon* in 2010. The dual-gradient equipment was removed to clear space and has remained in storage ever since.

That disaster ushered in major changes in offshore drilling regulation. Drillers have been focused on complying with those changes as they geared up to resume work in the Gulf of Mexico. The future for Transocean’s idea, and the other varieties, will depend on finding operators willing to champion ideas with long-term commitments. “It is now coming up because of demand by operators,” Kozicz said. “We need the Chevrongs of the world to provide a push.” **JPT**

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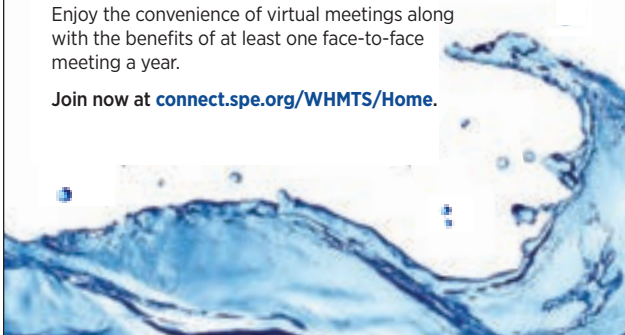
OTC 25292 ECD Management Toolbox for Floating Drilling Units
by John-Morten Godhavn, Statoil; Roger Stave, Enhanced Drilling, et al.

OTC 25256 Enhancing Well Control Through Managed-Pressure Drilling
by Oscar Gabaldon, Martin Culen, Pat Brand, Blade Energy Partners.

SPE 164561 Successful Application of Deepwater Dual-Gradient Drilling
by Paul Richard Ashley, Petronas; Roger Stave, Enhanced Drilling; Robert Ziegler, Petronas, et al.

OTC 22889 A Step Change in Safety: Drilling Deepwater Wells with Riser Margin
by Robert Ziegler, Petronas.

SPE 163523 Operational Reliability Assessment of Conventional Drilling vs. MPD on Challenging Offshore Wells
by Don Hannegan, Weatherford.



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BOP Monitoring Seeks To Reduce Downtime, Increase Insight

Trent Jacobs, *JPT* Technology Writer

A growing trend of heavy industries in the 21st century has been to marry computers and software with large machines to track their performance, and all the hiccups along the way. Known as condition-based monitoring, the process is used to enhance the reliability and performance of railroads, wind turbines, nuclear reactors, and jet engines, but not subsea blowout preventers (BOPs). However, that is slowly starting to change.

All three major BOP makers, as well as some other companies, have introduced BOP monitoring systems that seek to provide new insight into how these massive subsea machines work—and perhaps more important, why they sometimes do

not. By improving system reliability, the offshore drilling industry stands to recoup millions of dollars it writes down each year because of BOP downtime.

Today, offshore drillers have little knowledge about the fatigue life of the more than 100 hydroelectric valves and regulators inside a BOP. Makers of BOPs acknowledge that this uncertainty forces companies to replace as much as 25% of the BOP stack each time it undergoes scheduled maintenance to mitigate breakdowns. The practice of arbitrarily replacing parts is only a stopgap measure as drilling contractors report that 50% of downtime on their drilling rigs are caused by problems with BOPs. While they have their differences, the BOP mon-

itoring systems available today seek to completely change this status quo. “The holy grail is to detect a failure early and focus your maintenance efforts on that part, and not just a random part,” said Clayton Simmons, product line manager of BOP monitoring systems at National Oilwell Varco (NOV).

These monitoring systems take readings from the BOP stack and route it to a computer server where software is used to determine how critical components are functioning. The thinking is that if a drilling contractor can predict a problem, or how far along a part is in its service life, then the BOP can stay on the bottom longer without coming up to the rig for repairs. “Compared to where the industry

The merging of monitoring technologies with easy-to-interpret interfaces for subsea blowout preventers (BOPs) offers drilling contractors a new tool to understand the condition of their system before it breaks down. For many offshore drilling contractors, BOP failures account for half of the total downtime on their rigs. *Photo courtesy of GE Oil and Gas.*

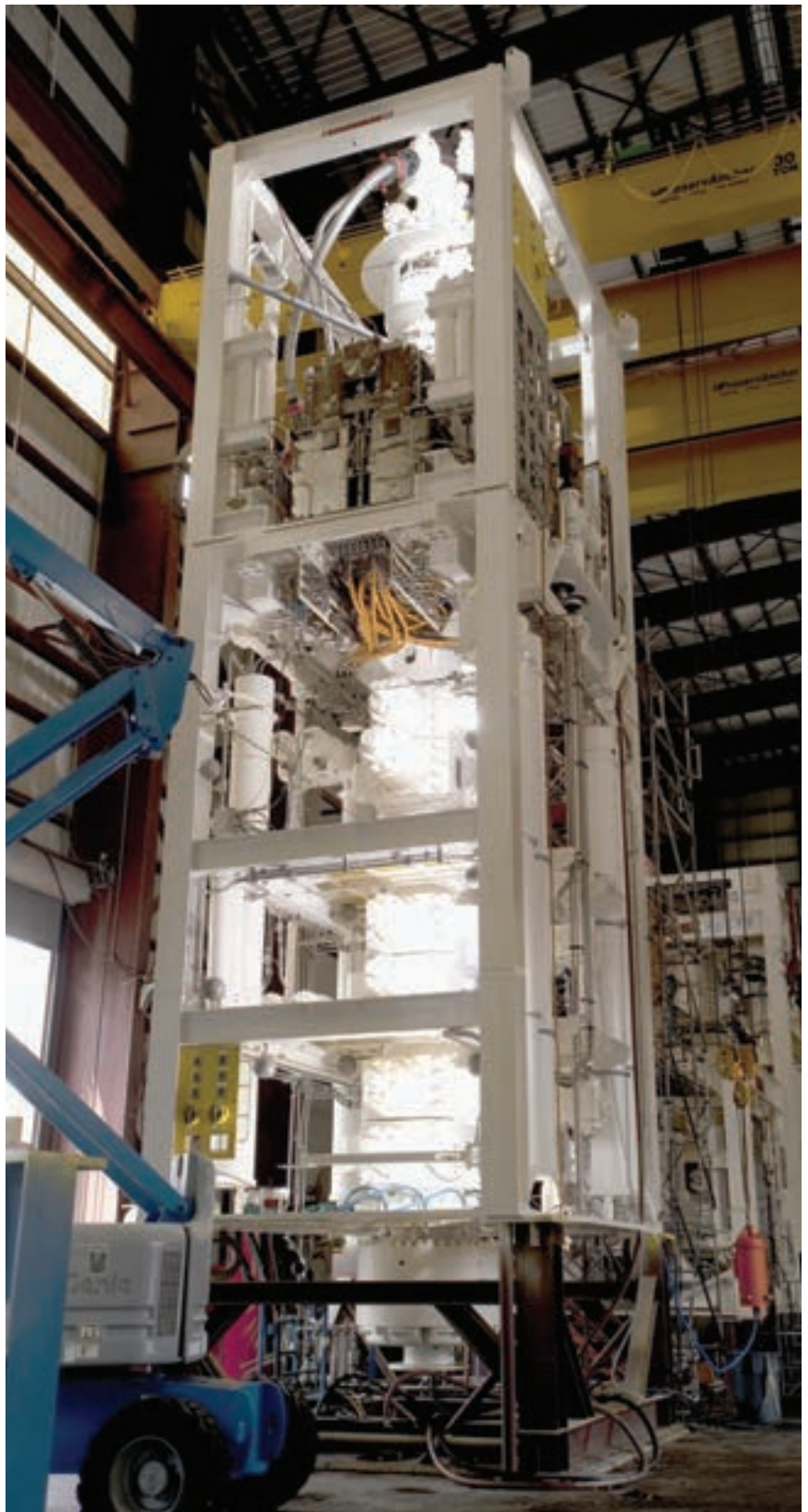
is now, this is a crystal ball,” said David McWhorter, vice president and general manager of drilling systems at Cameron.

Because this technology is relatively new and is being used only on a handful of offshore rigs, it will take time to collect enough information to change how the industry addresses maintenance issues. A future step for many of the technology developers will be to use sensors on and inside the BOP to gather more information for the analytic software programmed to serve as automated maintenance advisers to offshore drilling contractors.

Increasing Demand

NOV installed its BOP monitoring system on its first rig over 3 years ago; now the system is being tested on three rigs and the company expects that number to grow to 10 this year. In its second phase of development, the company’s monitoring system is facing increased competition. GE Oil and Gas and Cameron unveiled new BOP monitoring systems at the Offshore Technology Conference in Houston in May. Cameron is upgrading its first BOP with its monitoring system and two companies, US-based Atwood Oceanics and Brazilian-based Queiroz Galvão Óleo e Gás, have ordered monitoring systems from GE.

Ashford Technical Services was the first to introduce a BOP monitoring system in 2009 on a Diamond Offshore drilling rig in the US Gulf of Mexico. Since then, the company has installed monitoring systems on three rigs operating in Asia Pacific and Australia, and on a rig that is heading to the North Sea.



GE’s new monitoring system, Sealytics, can be installed on new BOPs or retrofitted onto those already in service. *Photo courtesy of GE Oil and Gas.*

BLOWOUT PREVENTER TECHNOLOGY



Cameron introduced its BOP monitoring system, Cognition, at this year's Offshore Technology Conference in Houston. The system monitors the condition of every moving part in a BOP by interpreting the electrical signatures produced when each component is actuated. *Image courtesy of Cameron.*

The company said it is expecting to add the system to another rig in the coming months. Most of the installations are for medium-depth and deepwater rigs.

Despite the growing number of rigs using BOP monitoring systems, the technology is still on the low side of the uptake curve. One potential factor

that could increase adoption remains in doubt. Some in the offshore industry thought that subsea BOP monitoring would become a requirement for drilling in US waters after the *Deepwater Horizon* blowout in 2010 that killed 11 crewmen, but "right now, there is no industry regulatory driver for

this," said McWhorter. "This is simply good business."

Unknown Life Cycles

Overhauling the offshore drilling industry's maintenance practices will begin with knowing the life cycle of an individual component. A 2013 report made public by the Bureau of Safety and Environmental Enforcement (BSEE), the primary offshore regulatory body in the United States, highlighted the need for monitoring systems by citing an example of a BOP test gone wrong. The report recounted an undated event involving a deepwater rig that was unable to complete a subsea test of the BOP's shear ram when a control valve malfunctioned.

The BOP had to be pulled up to the rig and fixed before being sent back down to the well. The 2-week process cost the drilling contractor more than USD 10 million in lost revenue. The BSEE report concluded that had the drilling contractor known how many cycles the valve had been through, the component could have been replaced before it failed.

Without knowing the durability of each part, most drilling contractors have adopted a time-based maintenance program that calls for the replacement of up to a quarter of a BOP's moving parts once a year—whether they need to be or not. "What is the expected lifetime of that valve in terms of number of cycles? If you ask the manufacturer, you do not get a very good answer," said Frank Chapman, president of Ashford.

His company has been collecting data from its monitoring system, RigWatcher, for nearly 6 years and is ready to start mining the data to determine the life cycles of BOP parts. Chapman envisions that this could one day help BOP makers design longer-lasting valves and other components. Detailed usage and fatigue information has to be collected from each valve and then compared with the stated life expectancy of the component. "Given that, then you can start to improve the manufacturing process or the design so that you can increase that life cycle," Chapman said. "But without any data to start with, you are shooting into the dark."



NOV's BOP monitoring system, eHawk, uses a color-coded dashboard system to indicate the level of risk associated with each component. The company is running a pilot program with the system on two Ensco drillships operated by BP. *Image courtesy of NOV.*

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Valve (R)	Tag Number	Equipment Id	Function	Location	Current Cycles	Max Cycles	Percent Max Cycles
Upper Annular Preventer							
Solenoid 4W2P (1)	T2127	69W34A	Open	HPU	333	5000	6.66
Solenoid 4W2P (2)	T2128	791BA	Close	HPU	334	5000	6.68
Manipulator 4W3P (3)	T2129	R3433	Open/Block/Close	HPU	333	5000	6.66
SPM 4W2P (4)	T2130	6R441D	Open	Blue Pod	224	5000	4.48
SPM 4W2P (5)	T2131	DD6671	Close	Blue Pod	225	5000	4.5
SPM 4W2P (6)	T2132	GG4511	Open	Yellow Pod	112	5000	2.24
SPM 4W2P (7)	T2133	6HR1332	Close	Yellow Pod	112	5000	2.24
Shuttle (8)	T2134	439011	Open	BOP	331	5000	6.62
Shuttle (9)	T2135	722-12G	Close	BOP	332	5000	6.64

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RigWatcher, a BOP monitoring system introduced in 2009, keeps track of the number of cycles each component has been through to help establish the service life of the part so it can be replaced before it fails. *Image courtesy of Ashford Technical Services.*

Using Dark Data

Monitoring systems available today rely upon the raw data generated when commands are sent from the rig to the BOP

control pod to turn a valve or close a ram. The monitoring systems obtain the data and transmit it without interfering with the control system. This eliminates the

risk of unintentionally causing a problem within the BOP control system. Although a BOP is a hydraulically controlled system, each action that it performs produces a unique electrical signature in the control pod that is recorded. Using a monitoring system's algorithms, the signatures are interpreted to determine the health of an individual moving part.

Because these electrical signatures have traditionally taken a lot of time and effort to properly interpret, some call it "dark data." This raw data is now the crux of most monitoring systems, including GE's SeaLytics, and will be used to begin establishing performance trends and creating new maintenance guidelines, said Bob Judge, director of product management for drilling systems at GE. "We had this nice set of data that we didn't do anything with," he said. "Nobody was shining a light on it, and saying, 'What can I learn from this?'"

Each company has designed its own user interface to present the processed monitoring data in a way that highlights the most important information to a driller. The displays mix real-time data with historical information and performance projections to aid in predictive maintenance. On an offshore rig without a monitoring system, how does a

TRANSOCEAN GOING ITS OWN WAY

Absent from the list of drilling contractors using commercially available blowout preventer (BOP) monitoring systems is the world's largest: Transocean. That is because the company is taking its own approach. Last year, Transocean announced that it is working on a 3-year project with Shell to develop fault-resistant and fault-tolerant control systems that could be used to retrofit BOPs currently in use. A control system acts as the nerve center of a BOP and when it goes down, so goes the entire stack. Unfortunately for Transocean and many other drilling contractors, breakdowns happen frequently as control system failures are attributed to roughly half of the downtime incurred by BOPs.

When it comes to the BOP monitoring systems offered by other companies, Transocean's director of technology and innovation, Jose Gutierrez, said what his company is looking for is yet to be developed, and made the case that simpler is better. "We do not need to do deep analytics,"

he said. "If you want to know when something is going to fail, just count how many times you have used it—count the cycles."

Gutierrez said he and his subsea engineers are concerned about relying on sensors to monitor a BOP. They point to the risk of the sensors themselves failing, which could cause a driller to unnecessarily pull a BOP stack off the well. Others point to the risks created by inserting sensors and cables inside pressurized areas of the BOP. "We should have more BOP data but we do not have the sensors to get it," he said. However, he points out, "If we put sensors in, then there is another challenge since it would be another point of failure."

Nonetheless, Gutierrez added that drilling contractors have been able to cope with the problems that sensors introduce, and successfully reduce repair times and increase the time that it takes to reach a failure by using the proper sensors. "It is a complex problem, but it is a solvable problem," he noted.



Complete History of BOP Activity



At left, the tool pusher's panel on the rig shows only the current status of each moving part in a blowout preventer (BOP). At right, a BOP monitoring system provides the tool pusher with a 24-hour status report of some of the most critical components in a BOP. *Images courtesy of Ashford Technical Services.*

tool pusher or rig superintendent know the BOP's valves actually turned, or the rams actually closed? In short, they do not. Workers on the rig must instead use indirect information, such as flow and pressure, to determine if the BOP carried out the function as instructed. BOP monitoring systems will dig a little deeper by taking the flow and pressure information, along with the hydraulic and electronic signature produced by the valve, to determine if it is working normal or not. The anomalies are then automatically entered into a maintenance report and the component in question is singled out for inspection.

For instance, if the BOP is equipped with the proper sensor, a monitoring system will record how long the shear rams took to close and if they are slowing down over time, the software will try to predict when they may wear out. Judge noted that it takes some time for the software to sort out the signals and what they indicate. "With all these programs that rely on data," he said, "you have to start somewhere; once you start collecting the data, then you can analyze it."

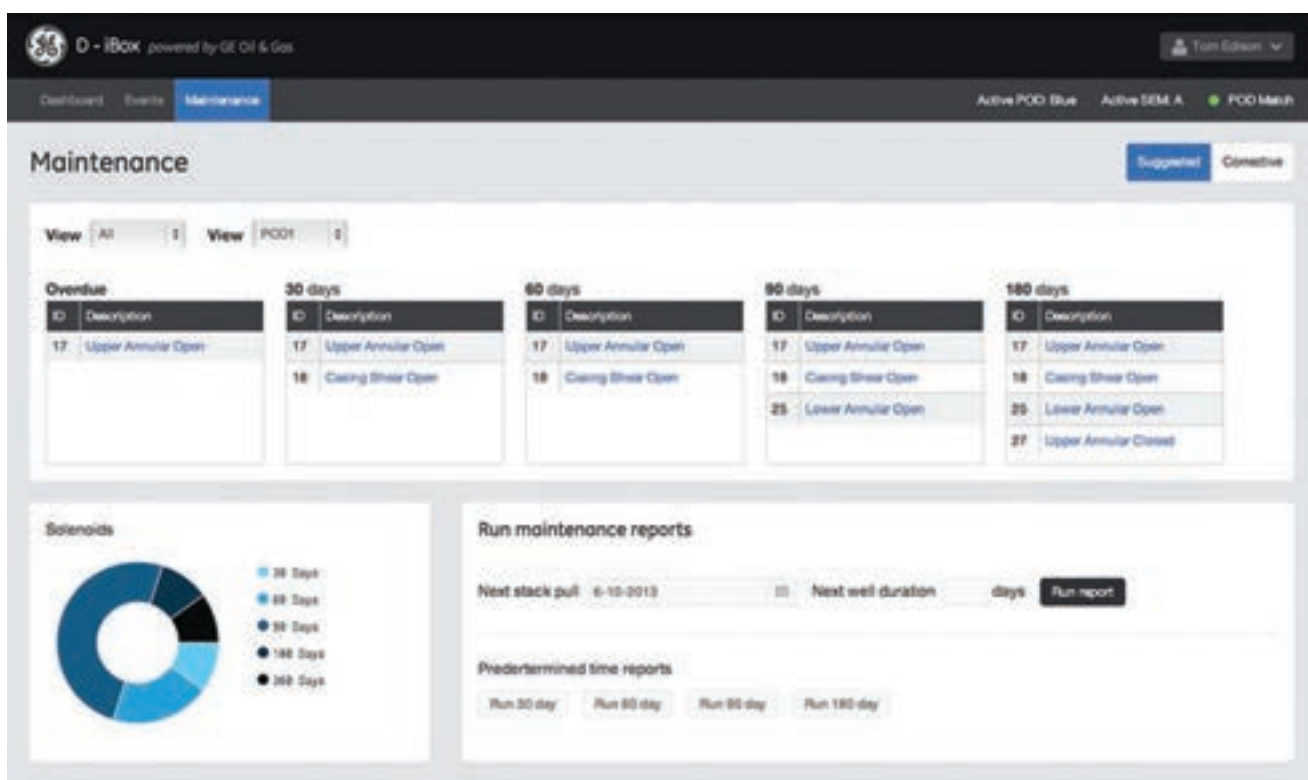
NOV is beginning to sort out the meaning of the signals. The company is entering the second phase of its 2-year-long pilot program to assess its monitoring system, eHawk, which is installed on two Ensco-owned rigs and one Noble rig. NOV is storing BOP data at its own onshore facility where it is aggregated and made available to the drilling contractor through a user interface. By next year, it hopes to use this information to establish baselines of normal performance signatures from those associated with the wearing down of a part. Simmons said that by separating the good hydraulic signatures from the bad ones, "we can help them focus on a specific valve that may be showing an odd signature, that may be passing a pressure or function test, but could possibly fail the next time it is deployed."

Subsea Sensors

One major consideration concerning BOP monitoring is the use of sensors. A popular school of thought says adding sensors means adding more components that can break down and lead to the BOP

being pulled. This is part of the reason that of today's monitoring systems, none are inherently reliant on aftermarket sensors to collect data but the developers expect sensors to take on a greater role as monitoring technology matures. "We have a really good data set without a lot of additional instrumentation," said Judge who noted that adding a system, such as SeaLytics, to a BOP is easier than adding a new sensor to it. However, "if there are missing links in the data, that too will be revealed through the software and then a sensor can be designed to be installed to gather the data," he said.

Cameron's engineers see the potential for up to 80 kinds of sensors to be placed on a BOP to gather condition data—customers will ultimately decide how many they want to install. These sensors could track temperature and pressure changes and the condition of the accumulator bottles. One of the sensor systems that Cameron is working on is an ultrasonic device that can tell within a fraction of an inch the location of each piston inside the BOP. The sensor was originally designed to measure gas flow.



The key benefit of monitoring systems is that they enable predictive maintenance. The maintenance regime employed by offshore drillers dictates that up to 25% of the moving parts be switched out with new ones to mitigate failures and maintenance problems. *Image courtesy of GE Oil and Gas.*

“It is a key part of the technology and we envision that it will be one of the primary sensor types that will be employed in this system,” McWhorter said.

GE upgraded its BOP ram position indicators, a technology based on *Deep-water Horizon* learnings, that indicates the degree to which the rams are open or closed by using a pressure transducer that records the amount of pressure it took to complete the action. “As the pressure fluctuates over time,” Judge said, “that is telling you something about the health of what is inside those things.”

Enabling Onshore Experience

As far as communication goes, today’s BOPs are simple creatures. Basic, yet critical, operational data is sent from the BOP back up to the rig floor where temperature and pressure readings are displayed. And it stops there. If a project manager working onshore needs to know the status of the BOP, for instance, as a means to determine well pressure, then

he or she would either have to wait for a daily email update or phone the rig and request the information. The monitoring systems allow the drilling contractor to link the information coming off the rig to anywhere in the world via satellite uplinks and the Internet.

With remote monitoring, a team of onshore specialists can troubleshoot problems on not only one rig, but also multiple rigs. “You can bring the experts you need around the table pretty quickly without having to put them on a plane and a helicopter to get them to the rig,” said Judge. Instead, “they just pull it up on their laptop and see what is happening,” he said.

Monitoring systems can also help the industry in coping with the “great crew change.” The industry is losing many of its most experienced personnel to retirement and filling the ranks will be talented, but less experienced workers. With a BOP monitoring system that is integrated with an onshore operations center, “one

senior subsea technician, for example, can assist many junior technicians that are on the rig,” said Simmons of NOV. “He is looking at the same diagnostic screen as on the rig, but he has more experience and can help make better decisions.”

Bigger Data Ahead

For GE, one of the next steps in the evolution of its monitoring system will be to combine the performance and condition data from different drilling contractors, and store this information in a secure database in which the aggregate data could be used to provide fleet-wide performance learnings. Collecting operational data from machinery for pattern analysis is a common practice in the transportation and energy generation industries; however, it is not happening in the offshore industry. While some of GE’s other business units have persuaded customers from the transportation, aviation, and energy generation industries to share performance information, “I do



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BOP BLACK BOXES

Most companies using blowout preventer (BOP) monitoring systems have developed so-called black box technology that stores vital forensic data to assist in emergency responses and investigations of well control incidents or a sinking rig.

The genesis of Cameron's newly unveiled BOP monitoring system was born from the development of a BOP black box. The company's hardened system records and stores 3 weeks' worth of data that can be retrieved using a remotely operated vehicle (ROV).

One of NOV's black box systems is located on board the rig and in a catastrophe in which the rig is lost, the black box is jettisoned into the water. Equipped with a homing beacon, an ROV can recover the black box from the bottom of the sea and retrieve the data. GE Oil and Gas has also introduced a black box modeled after the technology that its aviation business provides to commercial airliners.

Trendsetter Engineering, a company specializing in well control equipment, will be introducing its black box technology next year. In addition to BOPs, the black box can be installed on subsea production systems and trees. "It is the same idea as a black box for an airplane," said Mauricio Madrid, director of projects at

Trendsetter. "It is independently powered and information is independently retrieved."

The company's black box works by continuously monitoring, gathering, and storing all the critical information being produced by electronic sensors on a BOP. In addition to operational data, Trendsetter has designed its black box system to store the final engineering drawings used to build the BOP, well plans, schematics, part numbers, and historical data, such as each time the device was tested and certified.

The data inside the black box can be transmitted to a ROV using an acoustic data system, so a wet-mate connection is not required. In a single pass, the ROV can download the information from the black box and transmit it in real time to the surface by means of the ROV's umbilical. The value is that all the information about the BOP, the well, and even the rig is centralized and easily accessible to incident responders to aid in their decision making, and later for an investigation. "This black box concept is just another step change in getting people to understand that we cannot continue to do things the way we were doing them before," said Madrid. "We have to think outside the box and mitigate unforeseen issues."

not think it happened overnight," Judge said, noting that it is a long-term goal.

Moving forward with the development of its monitoring system, Cameron plans to work closely with its customers to come up with additional algorithms that will best suit their needs. Its customers can use the analytic systems that Cameron designed, third-party protocols, or extract the data and apply their own analytics. NOV purchased artificial intelligence software to validate its results and refine its approach. The company also has plans to release analytic programming later this year to its drilling contractor customers to allow them to analyze the data themselves.

Future Sensor Development

Cameron's monitoring system is also designed to determine the condition of the rubber packers inside the BOP. Like all rubber components, the material degrades over time and the system is used to identify how far along they are in their fatigue life. "That is something that is very, very difficult to do when you are

on a well subsea," McWhorter said. "We know that there is a virtual one-to-one correlation with the position of the piston and how much rubber volume is left," he said. "So if you know the position of the piston, if you know the pressure that may be on that packer, you can tell how much rubber is used up."

McWhorter noted that this feature could be even more valued when evaluating the condition of a BOP's annular packers. "Unlike ram packers, which just open and close on static pipe for most of their life, annular packers are subject to having pipe stripped through them, tool joints pulled through them, pipe rotated, and all kinds of events that can accelerate the wear of that annular packer," he said.

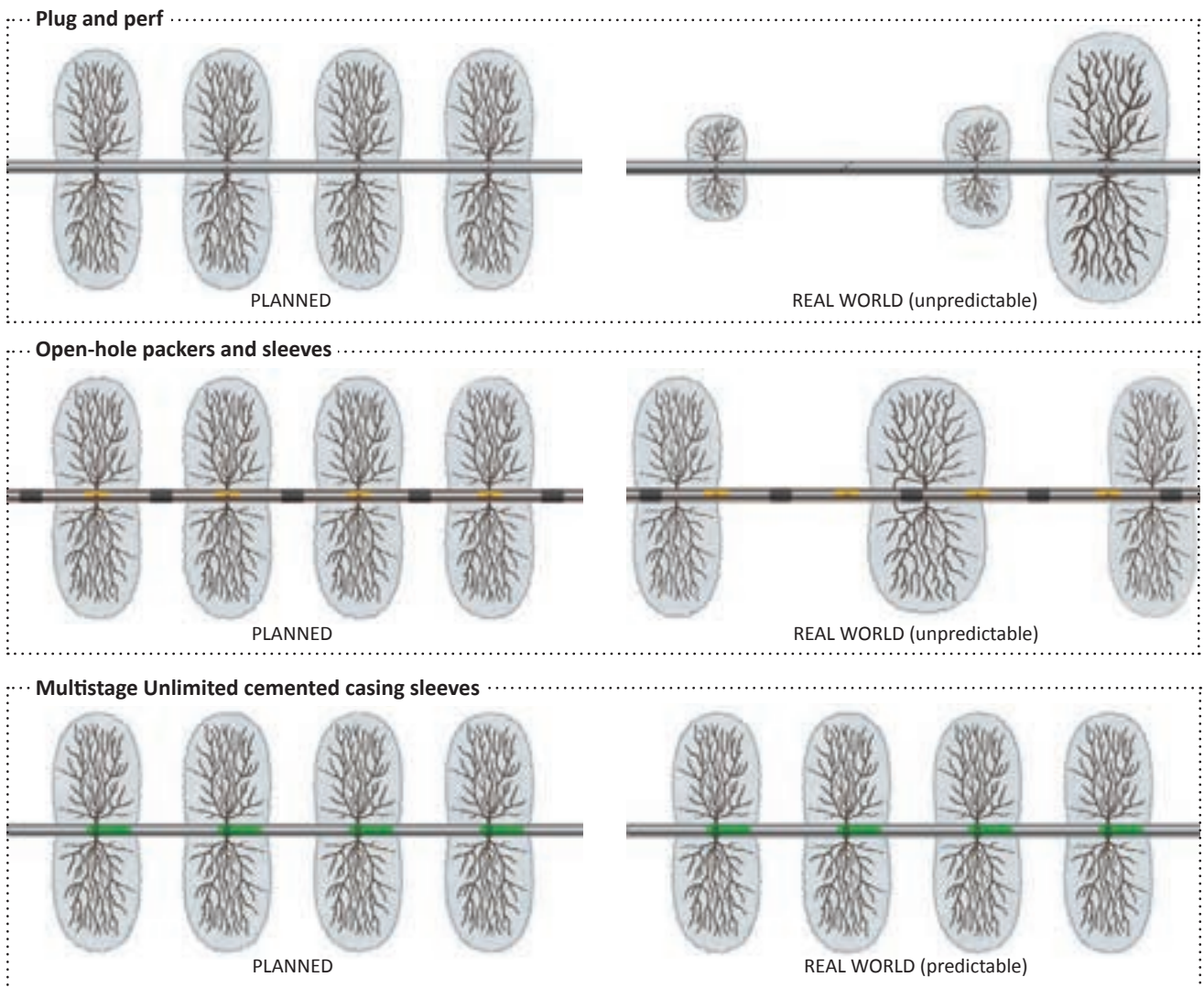
Cameron is developing a sensor that will be placed inside the borehole of the BOP to analyze the fluid makeup as it flows up to the rig to see if bits of metal or pieces of rubber from a seal are present. It said these problems are known to have a direct effect on the condition of the pistons and valves inside a BOP stack. McWhorter said, "If we perfect that sen-

sor and we can perfect the algorithm that goes along with it that has the ability to give an operator or drilling contractor the confidence that the condition of their fluid is good."

NOV is looking for a way to detect the contamination level of the BOP's hydraulic fluids. A BOP's hydraulic fluid is 97% water and 3% glycol. As with any standing body of water, bacteria and algae begin to form colonies, which can cause serious damage to a machine such as a BOP. Currently, routine samples are taken from BOPs while on the rig and mailed off to be analyzed. "By the time those results come back in," Simmons said, "the (BOP) likely has already been flushed and you have a whole new set of fluids in there, so it is very tough to determine what is actually happening to your system with regard to contaminant level in the fluid." Working with its customers, NOV thinks it can use a sensor to monitor the buildup of bacteria and algae in real time so the crews on the rig can change the hydraulic fluids out sooner or change filters to prevent contamination. **JPT**

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Unconventionals, Technical Challenges Highlight Offshore Technology Conference

The impact of onshore unconventional development on the offshore sector, safety and environmental protection, and new opportunities and their technical challenges highlighted sessions and discussions during the annual Offshore Technology Conference (OTC), held 5–8 May in Houston. The broad program and exhibition, which attracted a record crowd, featured operators, independents, service companies, academia, and government officials weighing in on some of the most complex and pressing challenges facing the offshore industry.

The surge in North American shale

development has brought major portfolio changes to E&P companies. This was the focus of one session in which six panelists discussed the impact of the unconventional “revolution” on the offshore deepwater industry.

Darrell Hollek, senior vice president for deepwater Americas operations and development at Anadarko, noted the huge change in his company’s production mix in the past 4 years. “If you go back (only) as far as 2010, we really had not drilled any horizontal wells,” he said. From that base of virtually no shale production, Anadarko has ramped up to production of 370,000 BOE/D from unconventional resources in 2014, and unconventional plays represent about

70% of the company’s capital budget, Hollek said.

Nonetheless, Anadarko’s mid-cycle and long-cycle projects—chiefly offshore activity, including deepwater projects—play a crucial role through generating high cash flow that has financed the company’s entry into onshore unconventional development, Hollek said.

Lee Tillman, president and chief executive officer of Marathon Oil, said that unconventional plays have shifted the balance in his company’s cap-



TILLMAN

VARIETY OF PROGRAMS SHOWCASE OTC’S DIVERSITY

Attendance at this year’s OTC was the highest in its history, as the conference attracted attendees from throughout the oil and gas industry with panel and technical sessions as well as special events. The annual conference, which debuted in 1969, featured nine panel sessions, 29 executive keynote presentations at luncheons and breakfasts, and 308 technical papers. Technical and panel sessions featured speakers from major, independent, and national operators; federal and regional government officials; and academia.

Among the highlights of this year’s conference:

- ▶ The Annual OTC Dinner was attended by more than 1,000 industry leaders and conference attendees, and raised USD 250,000 for Medical Bridges, an organization that recovers medical surplus that would otherwise be discarded and redistributes it to hospitals, clinics, and healthcare providers in less fortunate countries.
- ▶ The Distinguished Achievement Award was presented to Carl Arne Carlsen of DNV; the Distinguished Achievement Award for Companies, Organizations, or Institutions was awarded to BP for its Clair Ridge development; and the OTC Heritage Award was given to Noble Energy’s Susan Cunningham.

- ▶ OTC’s Spotlight on New Technology Award recognized 12 technologies for innovation in offshore production.
- ▶ More than 150 classroom teachers and 200 students attended the Energy Education Institute. Teachers learned about the scientific concepts of energy and students got to know more about oil and gas industry careers. University students participated in the conference’s University R&D Showcase while the Next Wave event featured a program for young professionals.

OTC officials also announced that a new event called “d5” will debut on Friday, 8 May 2015—the day following next year’s conference. The event is designed to bring together the best thinking and creativity from inside and outside the E&P industry to discuss and think innovatively about how to meet current and future challenges confronting the industry.

Total attendance at this year’s OTC reached 108,300, the highest in show history and up 3.3% from last year. The sold-out exhibition was the largest in the conference’s history and featured 2,568 companies representing 43 countries.



This year's OTC featured the largest exhibit in its history.

ital spending from less than 10% in 2008 to about 60% this year. The current budget for unconvensionals exceeds Marathon's entire 2008 E&P budget, he said.

Marathon's capital allocation, Tillman said, "has been driven by profitability, not geography or play type." Like Hollek, Tillman said that portfolios need to strike a balance between onshore unconventional development and offshore and deepwater projects. "It is not an either/or proposition," he said.

The two panelists from supermajor companies, David Eyton of BP and Greg Guidry of Shell, did not break down the

percentage of their companies' capital budgets devoted to unconventional plays.

"It depends how global you are," said Eyton, head of technology at BP. As the industry's current unconventional activity focuses heavily on North America, the portfolios of companies such as BP and Shell, with many large, long-term projects worldwide, are less weighted toward unconvensionals. But Eyton and Guidry both dwelt on the importance of unconvensionals in project portfolios.

The benefits of deepwater projects, Eyton said, stem from their scale, which brings higher capital requirements but provides longer paybacks and big-

ger margins. Unconventional resource opportunities vary worldwide but have high global potential, he said. "The modular nature of unconventional wells and the scope for experimentation within the fields have driven down—and we expect will continue driving down—costs faster than in deepwater," Eyton said. Technology challenges remain, including the need for continuous improvement in hydraulic fracturing, he said.

Getting it Right

Guidry, executive vice president for upstream Americas—unconventional at Shell, said, "Getting it right in terms

SESSION EXAMINES MEXICO ENERGY REFORM

Chris Carpenter, *JPT* Technology Editor, and **Jack Betz**, Staff Writer

Several sessions at OTC focused on the opening of Mexico's energy sector to private investment.

In a session titled, "Mexico Energy Reform: Challenges and Opportunities," Gustavo Hernández García, state oil company Pemex acting director of exploration and production, spoke about the future of the company.

In light of the energy reform measures now being discussed by Mexico's Congress, Pemex has embarked on a program to transform "from a state-controlled industry to a state-owned productive company" and, in the process, embrace partnerships with foreign companies and even foreign operators, he said.

Mexico has begun the reform in large part because of the country's decline in production over the past several years. Domestic demand for petroleum has remained steady, but the drop in production threatens the country's growth and has highlighted the fact that Pemex does not have the resources to develop the country's rich reserves. Deep water, shallow water heavy oil, shale, and enhanced oil recovery in mature fields are four places where Hernández García said the company plans to capitalize on opening up certain leases to outside operators and partners. According to Hernández García, Mexico still has 13 billion bbl of proven reserves in place, not counting prospective resources.

Pemex recently submitted to the government a list of the areas it wants to reserve for itself. After that process is complete, the company will pursue joint ventures with outside companies and, eventually, bidding rounds will take place where leases will be granted exclusively to outside operatorship, he said.

Hernández García described the aggressive 24-month schedule, launched in December of 2013, to change Mexico's longtime national oil company into a company that no longer functions as a branch of the Mexican federal government—a significant economic and political distinction. The transformation will introduce competition into the Mexican energy sector and will yield plentiful benefits, including a concentration upon value-driven enterprises, an enhancement of Pemex's technical competencies as partnerships are created with other entities, and a transparency of processes that will attract further investment. However, Hernández García explained, this transformation means an enormous amount of work as well as potential political and social tests.

In addition to the heavy legislative work that will shift the relationship between Pemex and international companies, Pemex itself faces a number of challenging internal tasks, including restructuring of its remuneration and salary schemes—a step that will affect, among others, the 61,000 Pemex employees in exploration and production alone—and placing emphasis on recruiting and hiring large numbers of talented technical personnel



Gustavo Hernández García is acting head of Pemex E&P.

required by expanding partnerships with international oil companies.

"We want to remain a top employer in a competitive environment and are committed to retaining talent," Hernández García said. The organizational changes will involve much deeper shifts than those affecting organizational charts or constitutional mandates, however; Hernández García went on to describe a necessary "change in our culture and mindset to become a results-oriented one" better able to operate in what he called an "increasingly technically complex environment."

In discussing the possibilities of partnerships with international oil companies, he said Pemex does have a number of well-established technical competencies, including in conventional onshore oil and gas as well as shallow-water production, but Hernández García said that Pemex knows it must encourage partnerships to best develop new expertise and to exploit Mexico's abundant unconventional resources better. These unconventional resources offer an enticing opportunity to the private sector; as an example, Hernández García cited the expanding operations in the Mexican portion of the Eagle Ford formation.

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Stephen Rassenfoss, *JPT* Emerging Technology Senior Editor

Angola's Block 17 is nearing the end of one era of development and the beginning of its next.

The prolific offshore area has been developed with a series of megaprojects including commissioning of the first floating, production, storage, and offloading (FPSO) vessel; production from the Girassol field coming on line in 2001; and the Pazflor development in 2011. Now, Total is working on the last major field development plan in the block that will include the FPSO Clov.

"This will be the end of megaproject development" there, Pascal Carrier, vice president of projects for Total Exploration and Production Angola, said during a presentation on "Deepwater Brownfields: Yes We Have to Tackle It Now." For Total and its partners, the focus will shift to optimizing the production plateau.

The future for Block 17 will depend, in large part, on a Total program known as Project Brown Field, which was created with a goal of creating an organizational model for future long-term work sustaining older fields, known as brownfield development.

While this group within the international oil company has a total budget that is on a megaproject scale, it needs to think small, with a relatively small number of people managing a huge number of contracts for incremental efforts that must remain within the tight budgets that come with older fields where potential yield is modest compared with new field development.

The organization within the organization was created to embody a diverse team seeking to extend the production plateaus of the fields, where the natural decline rate averages 10% a year, Carrier said. Current projects undertaken by the 2-year-old organization are expected to reduce decline rates to 5% a year and eventually better.

By 2019, work to extract more production from the current fields, and extend production to smaller, satellite fields, is expected to account for 26% of total output from Block 17, up from 14% in 2015.

The challenge is getting more out of the economically marginal projects at a profitable price per barrel. Using a variety of strategies, this independent-minded organization

is doing projects for 30% to 40% less than what it would have cost in the company historically, Carrier said. There are 210 people managing projects with a total capital expenditure budget of USD 8 billion. This megaproject scale work is run by a group where 60% of the staff is working on at least two projects.

Success will require maintaining the mentality of an independent oil company looking for lower-cost ways to produce more by considering a variety of options. Projects so far include drilling infill wells, adding subsea pumping systems, removing bottlenecks for oil processes, and tying nearby fields to the FPSOs.

The range of skills required is broad, with an organizational chart covering the skills found in a typical oil company. An essential skill for the group is managing large numbers of contracts and reducing engineering costs by applying "copy and paste" equipment choices when possible, he said, adding that the organization is charged with using new technologies "when value is added."

Also needed are the communication skills of service company employees to sell different ways of doing things to operating personnel running the fields, who have ideas based on experience on how best to manage fields.

A primary concern when planning brownfield upgrades is lost production. Project Brown Field staff are required to work with existing staffers to minimize shutdowns while replacing critical systems, such as a major upgrade to increase capacity of the water-oil separation system on the Dalia FPSO, where the growing volume of water limited oil output. Pre-assembled modules were installed and early planning focused on anticipating potential problems in connecting the new equipment. "We need to work earlier in the process to validate plans," Carrier said.

Looking forward, Total is expecting the Project Brown Field organization to shape megaprojects by anticipating the most effective brownfield development. Its mandate includes working with development teams on Angola Block 34 to ensure early development there will be compatible with plans to sustain long-term production.

of public perception" is the industry's most important requirement in onshore shale development, just as it is in offshore activity. "If we don't get it right in terms of acceptance of our activity, then it gets very, very tough for the technology to be able to have an opportunity."

From the standpoint of a company's reputation, offshore and onshore are

linked. "I can't think of any major incident in deepwater that would not have a dramatic impact on what we are doing onshore," he said. "And I can think of a number of incidents that would happen onshore that would have an impact on what we do offshore."

Guidry noted Shell's establishment of five global onshore tight oil

and gas operating principles, published in 2011 and updated since then. They include

- ▶ Safe and responsible design, construction, and operation of wells and facilities
- ▶ Protection of groundwater and reduction, as reasonably practicable, of potable water use

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WATER MANAGEMENT GROWS IN IMPORTANCE FOR OIL AND GAS INDUSTRY

Adam Wilson, Special Publications Editor

The increasing global scarcity of water means more companies need to see and begin treating water as an asset, said Emmanuel Garland, environmental expert with Total, during a topical luncheon titled “Water Management—Change of Paradigm: Water as an Asset.”

“Water is already a crucial issue and will shape the future,” he said. “Water is a need before being a waste.”

Globally, 1.1 billion people do not have access to clean drinking water, said Garland, senior environmental adviser at Total E&P, “and climate change will probably make it even worse in the future.”

As the global need for energy increases, oil and gas companies will continue to expand operations to meet demand. And “production of oil and gas requires ... huge quantities of water,” Garland said.

“Consequently,” he said, “it is the responsibility of the oil and gas industry to ensure that water is adequately considered ... in the decisions of the companies.” The industry’s handling of this responsibility—its ability to develop innovative means to reduce water uptake and maximize use and recycling—could affect companies’ social license to operate, he said.

As responsible users of clean water for oil and gas production, companies need to work on reducing the need for clean water in operations, Garland said, adding “that is a real challenge.”

In addition to reducing the need for clean water, companies also need to examine how they handle water



Emmanuel Garland of Total addresses the topical luncheon audience.

produced by oil and gas production operations. “Handling water in a responsible manner is not only good business,” he said, “it is critical for our future.”

Water produced from wells must be treated before it is disposed, and “treatment has been designed for many years for disposal in the environment,” Garland said. Many techniques exist for treating produced water; Garland

- Protection of air quality and control of fugitive emissions
- Reduction of operational footprint
- Engagement with local communities regarding potential socio-economic impacts of operations

Supporting these is a series of 59 “proof points” that provide specific examples of how the principles are met. “We’ve found that it’s an incredible dialogue tool,” Guidry said. He also cited the Rational Middle Energy Series, published by the Environmental Defense Fund (EDF), and the University of Texas-EDF methane emission studies as important dialogue resources and praised the Pittsburgh-based Center for Sustainable

Shale Development for its public engagement work.

Offshore Experience Taken Onshore

Torstein Hole, senior vice president of development and production North America at Statoil, noted his company’s entry into shale development in the Eagle Ford, Bakken, and Marcellus plays in the United States. Unconventional resource projects make up 10% of Statoil’s capital budget. While the unconventional sector differs from the company’s traditional offshore development business, Hole emphasized the centrality of safety and understanding risk to operations in both sectors.

Statoil has long experience in dealing with small Norwegian communi-

ties making the transition to oil production, which should be helpful as onshore unconventional resource development expands in North America and elsewhere, Hole said. The company has smoothly taken its offshore experience to onshore activity, he said.

The future demands greater efficiency throughout Statoil’s operations. The opportunity to use and develop new technology and standardize and simplify shale projects can increase efficiency and benefit other operations, while the onshore unconventional plays diversify Statoil’s portfolio risk, Hole said. Learning from North American shale operations will help the company in future opportunities elsewhere, including Australian and Russian shale acreage, he said.

mentioned that there are at least 80 proven techniques. The number of proven techniques, he pointed out, shows that no single technique works for every situation.

"The move today is now to treat for reuse and not to treat only for disposal," he said. "If you can reuse it, that is much, much better."

Human Factors Integral to Project Design

Another environmentally themed session examined the need for "human factors" to be considered at the beginning of projects and not as an afterthought. Six technical papers at the Human Factors Technical Session examined the role of human factors in offshore projects.

"We can relate about 80% of accidents and incidents in the marine industries to human error. It is very important that we get involved and that we get involved very early in the design," said Julie Pray, senior engineer in safety and human factors at ABS. Pray presented her paper on "Implementing Human Factors Engineering in Offshore Installation Design."

But having the human factor considered during the planning phase of a project is not always easy. Benjamin Poblete, chief consultant at Atkins, said, "It is always difficult because what happens is [the human factor] is often sold as a separate issue, a separate thing, which is like what HSE [health, safety, and environment] was. ... It took us 20 some-odd years to get back in to it, and I think human factors has to do the same thing. It has to blend right in so that everyone is speaking the same language during design. ... We have to get in early." Poblete presented a paper on "Human Factors in Hazard Analysis."

The industry has a way to go to integrate human factors in the front-end engineering and design of projects, but tracking the human role in accidents is an important step.

"I don't think, in the offshore industry, that we are even remotely close to where we should be in human factors," said Dave Hollaway, human factors engineering manager at ABS Consulting, while presenting his paper "Human Factors Analysis and Classification System: Investigatory Tool for Human Factors in Offshore Operational Safety."

Hollaway went on to build on the axiom "you can't manage what you can't measure." The system outlined in his paper is designed to do just that—measure the human factors involved in a project. The system uses a set of user-defined codes to categorize and analyze errors that have led to accidents.

The system is free to download and is designed to be simple to use. "It is not so complicated that the average HSE or human factors person could not use it," he said.

Brian Craig, professor at Lamar University, presented another paper concerned with tracking human factors, in this instance in the form of reported near-miss incidents. His paper, "Reporting Practices for Close Call [Near Miss] Reporting Systems," discussed the creation of a database of 44,000 of these incidents. "Basically, we are looking to identify best practices based on what the industry is currently doing," he said. "One of the goals of these projects is to share this data, these lessons learned, and corrective actions across the industry."

The creation of the database is part of a larger safety initiative that has as one of its goals the standardization of how near misses are reported.

Policy and Technology

James Slutz, president and managing director of Global Energy Strategies, a consultancy based near Washington, D.C., addressed issues of public policy and the industry's technology development. In the policy environment, the industry is viewed as a whole, rather than as separate segments such as offshore, deepwater, onshore, or Arctic, he said. "A failure in one area will impact other parts of the industry."

Slutz emphasized the industry's need to obtain or sustain public acceptance, or social license, to carry on its activities. Quoting a recent remark from "a senior official," Slutz said, "We have adequately defined the fringe, but there is a lot of work to do in the middle."

There are very few multistakeholder organizations that focus on science and future technology development related to oil and gas industry activities, and more work of this type is needed, Slutz said. Outstanding examples that he gave are the Canadian Oil Sands Innovation Alliance and the US-based Environmentally Friendly Drilling Systems Program.

Policymakers tend to think statically, while technology development is a dynamic process, Slutz said, and the industry must do more to convey the likely future direction of technology and the projects that will use it.

Learning From Megaprojects

The continually increasing complexity and difficulty of large projects was exam-

ined in another session. Titled "A Look Back at Offshore Megaprojects," the session included senior project management and production engineering officials looking at past and current projects to identify critical areas for improvement. Among them were operator-contractor integration, risk assessment, project standardization, and stakeholder engagement.

"Owners and contractors, we are in this together," said Gary Fischer, general manager of project consulting services at Chevron. "We need contractors to design, to fabricate, to install, to drill and complete (wells)." For today's projects, "I think we have to be able to manage the work, not the contractor," he said.

An issue that has come to the forefront is "how important the engineering schedule, the engineering planning

HURRICANES LEAD TO DECOMMISSIONING INNOVATIONS

Stephen Rassenfoss, *JPT* Emerging Technology Senior Editor

A destructive run of three hurricanes has been a catalyst for a flurry of innovations in decommissioning shallow-water wells in the US Gulf of Mexico. Faced with the costly job of removing more than 30 damaged platforms and other damaged structures, Chevron began a series of technology development partnerships that changed how it removes old structures.

That backlog has passed but the need for more efficient methods remains strong for Chevron, and the industry, which is faced with thousands of structures on the continental shelf for fields that are played out. The goal has been to “engineer out risk” said Don Stelling, president of Chevron Environmental Management Co.

The changes include new approaches such as lifting whole structures rather than cutting them up and removing them piece by piece; using a giant claw rather than cables, saving the many hours needed for a conventional lift; and now it is testing an abrasive cable to saw off supports below the water line, further reducing diving time.

“The mission was to do it more safely, and it is more efficient,” Stelling said. “We are saving money and eliminating a lot of risk.”

When Chevron began removing its platforms demolished by hurricanes Katrina, Rita, and Gustav, the standard procedure for removing structures was for divers to cut the rig into pieces and lift the pieces out. The death of a diver when trapped gases from cuttings exploded was a powerful reminder that diving has always been one of the most hazardous jobs associated with removals, he said.

Seeking a way to reduce dive time associated with decommissioning, Chevron partnered with the maker of an enormous floating crane, Versabar Lifting Specialists, to develop a system for using the arch-shaped device to lift retired cranes out in a single piece.

The risk and cost associated with removing toppled platforms were higher, and hurricane damage magnified the uncertainties associated with removing old structures. The cost is generally about seven times higher, Stelling said.

Chevron worked with Versabar to demonstrate it could do the job, picking up a structure after it had been cut from its

moorings. That led to a continuing series of collaborations to improve the method, and further reduce dive time.

The next step was The Claw, an apt description of the device that hangs from the top of the arch-shaped Versabar that is able to grab whole structures and lift them without the modifications needed to attach cables. For example, using the claw reduces time needed for lift from 1,400 hours or more to about 100 hours, Stelling said. It has adopted a device to shear metal parts, rather than use a torch, and will use remotely operated vehicles rather than divers when possible.

Now Versabar and Chevron are field testing a new device designed to cut the legs of platforms below the mudline using a long, abrasive tungsten carbide cable that is worked back and forth like a hack saw. In April, the device cut a steel caisson 15 ft below the mudline in 12 hours, said Jon Khachaturian, president and chief executive officer of Versabar.

That avoided the many hours of dive time required to clear out the mud in a 90-ft circle around a caisson to provide divers access. One surprise from the test was mud proved to be tougher to cut than steel, requiring seven hours compared with five for cutting steel.

Another innovation coming soon will be the splash diving boat, which is now under construction for delivery later this summer. The most notable feature of the vessel from Aqueos is a power system that uses jets rather than propellers, allowing it to hold its position at dive sites where dropping an anchor could damage pipelines below.

It is also designed to move faster, make it easier for divers to enter and leave the water, and warn encroaching boats with a system developed by the US military that sends a warning sound in multiple languages that can be heard more than 1,000 yards away to boats that do not respond to radio calls.

The Gulf of Mexico has been a technology development center for Chevron Environmental Management, but its mandate is global with projects in 35 countries. The large-scale decommissioning going on the Gulf of Mexico, where it has 450 structures to go, is getting it ready for what comes next. “There is technology developed in the Gulf of Mexico that we will use around the world,” Stelling said.

is to the overall success of a megaproject,” Fischer said. “We have found something like 60% of projects, big projects, had very significant schedule overruns.” The main reason has often been that “we lost the schedule in engineering, and it was unrecoverable,” Fischer said. “I’ll be really provocative now. I don’t think we

know how to measure engineering progress any more.”

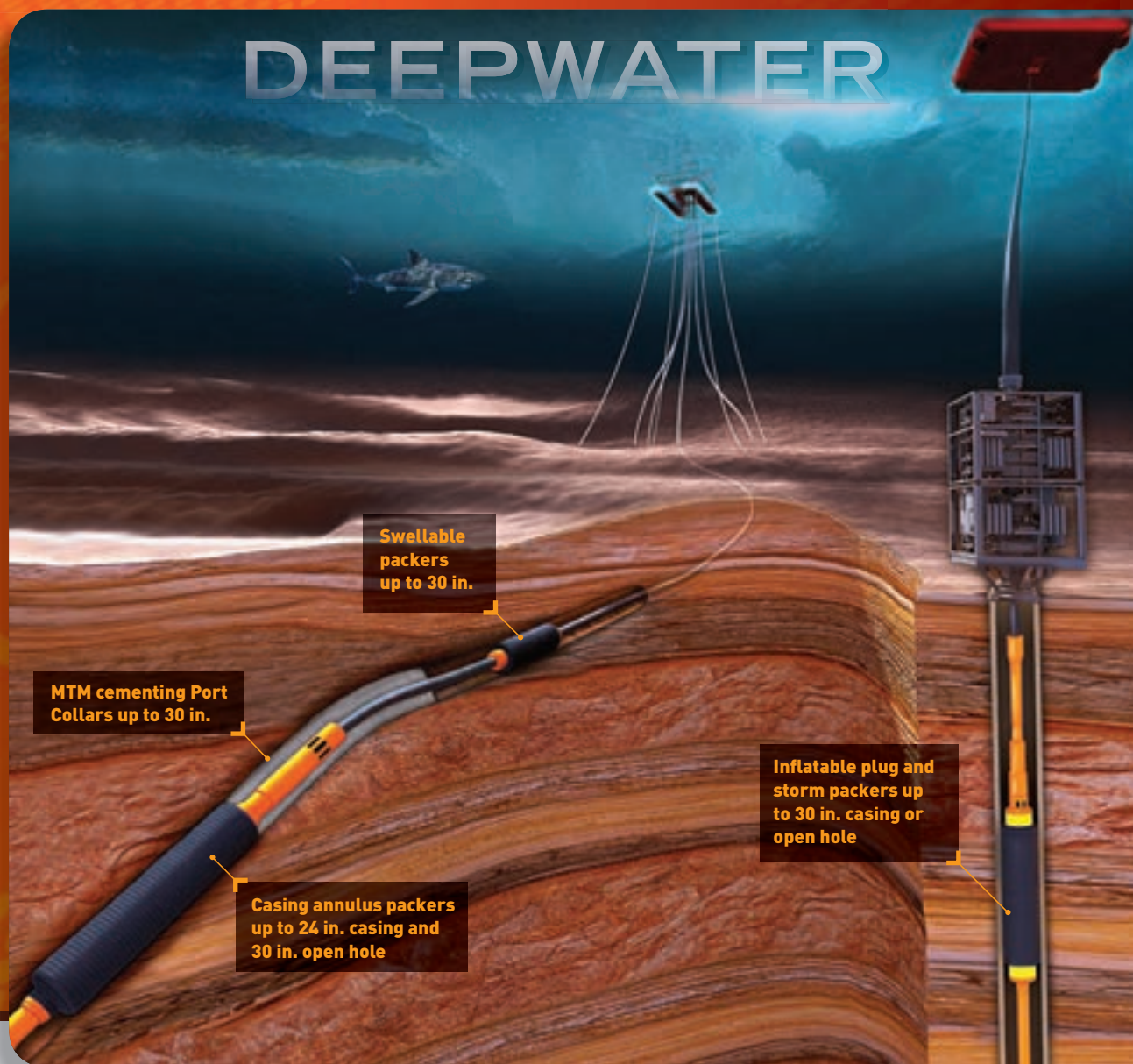
Contracting Strategy Critical

Thomas Ayers, chief operating officer for the offshore business unit at Technip, said, “One of the things that’s critical on making these projects work, and

work with the cooperation between the company and contractors, (is) it starts with the contracting strategy. You’ve got to have a contract that allows the project team to work together. You have to live by the contract. If your contract is not flexible to provide to do that, then you’re almost doomed to failure from the very

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beginning.” Before the project starts, the parties must have a common understanding of what the contract means, he said.

Ayers added, “You can’t focus enough on the risk and what you are going to do about it. Gone are the days when you can throw money at something and have it go away. Our margins are razor thin.”

Fischer said, “We as owners need to be careful and thoughtful about how we

allocate risk in the bigger picture so we can set up a successful project environment, which is in our own self-interest, to have our contractors win. We want them to win. We want them to be incredibly successful, and we want to win together.”

Regarding the allocation of owner/contractor responsibilities, Fischer said, “Do the best fit you can between the work that needs to be done and the people that really know how to do it right.”

Bob Buck, production engineering manager for Gulf of Mexico (GOM) deep-water operations at Anadarko, discussed the key elements of his company’s strategy for managing major offshore projects.

Owner/Contractor Relationships

It is important to develop long-term relationships with contractors, Buck said. “We even go as far as introducing our contractors to our relationship-based safety program called Rig Safe, which is about improving safety through improving relationships,” he said. “And so, by doing that, we demonstrate to contractors that we value them and esteem them, that we empower them to do the job. We listen to them; we have comments and suggestions. It makes our employees think of their employees as well.”

Anadarko also tries to standardize as much as possible, including controls, equipment, and processes, which provides helpful continuity for contractor employees, Buck said. In addition, he stressed the need to engage all project stakeholders. “Get them involved early,” Buck said, which helps to clarify what is expected. “As a company, we push the decision making down closer to where the work is actually being performed,” he said.

Discussing facilities design, Buck noted Anadarko’s decision to design and construct duplicate truss spars for the Lucius and Heidelberg deepwater projects in the GOM. Lucius is expected to begin oil and gas production this year. But building identical facilities will enable Anadarko to start production at Heidelberg in 2016, compared with 2018 had individualized facilities been designed and contracted.

“We know it is a bigger design than what we needed,” Buck said. “But with the time value of money, it made the project come on line 2 years earlier It’s not fit for purpose. It doesn’t have to be. It makes economic sense.”

Funding E&P Technologies

Collaboration between oil and gas companies, universities, and service providers is critical to address common chal-

allenges facing the oil and gas industry as well as to finance new exploration and production (E&P) technologies, according to panelists during the session titled "Funding New E&P Technologies."

The industry should move forward with deploying new technology because new technology is valuable only if it can be successfully deployed, and this requires operator uptake or pull. While established service and manufacturing companies supply the bulk of new E&P technology, a number of different organizations provide alternative funding mechanisms. The panel session examined six existing organizations that help finance new technologies and promote collaboration among industry peers.

Brad Burke, managing director of the Rice Alliance for technology and entrepreneurship at Rice University, said that universities play a critical role in developing and sourcing new E&P technologies. Burke said that his university is one of the leading players in this domain and helps in promoting newly developed E&P technologies through a series of events it hosts that allow meetings among developers, investors, and end users.

Burke said that since its inception in 2000, the Rice Alliance has assisted in the launch of more than 250 start-ups, which have raised more than half a billion dollars in early-stage capital. More than 1,000 companies have presented at the 125-plus programs hosted by the Rice Alliance.

Greg Kusinski, director and advisor at the global deepwater technology development consortium, DeepStar, at Chevron, said that significant new oil production is needed to meet world energy demand. "New oil production will come from increasingly complex resources, which will require additional investments between USD 7 trillion–10 trillion," he said.

Kusinski said collaboration is key for oil and gas companies mainly in deepwater R&D. "Collaboration in certain projects can be very beneficial for companies rather than competition, mainly in the areas of health and safety and environment," he said. "DeepStar is a recognized

industry voice, where there is an opportunity for members to further benefit by participating in fewer, but larger projects," he said. DeepStar is an operator-funded global research and development collaboration among oil companies, vendors, regulators, and academic/research institutions that began in 1991, Kusinski said.

DeepStar's current Phase XI program is focused on global deepwater development in water depths to 10,000 ft and deeper. "Its mission is to facilitate a cooperative, globally aligned effort focused on identification and development of economically viable methods to drill, produce, and transport hydrocarbons from deep water," he added.

Patrick O'Brien, chief executive of Industry Technology Facilitator (ITF), said that since the inception of ITF, it has managed to launch more than 200 joint industry projects. "Currently, we have just over 30 ongoing joint industry projects with direct member investment of circa USD 27 million," O'Brien said. "Our mission is to identify the best available innovators from the global research and technology development community."

O'Brien also said the E&P trend is to find new ways to operate in frontier environments, which means moving to ultradeepwater and developing the technology to not only drill but develop the fields in an economically effective manner. Making a discovery that cannot be developed for 10 years does not make sense, he said.

Panelists agreed that the presence of organizations such as ITF and DeepStar are critical to financing new E&P technologies, as they play the role of facilitator among different parties including operators, service companies, and developers. "The main purpose of organizations like these is to create stakeholder value by focusing on common industry challenges, and opportunities," O'Brien said. **JPT**

JPT staff Jack Betz, Chris Carpenter, Abdelghani Henni, Trent Jacobs, Joel Parshall, Stephen Rassenfoss, and Adam Wilson contributed to this OTC report.

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Qatar Focuses on Building Energy R&D Capacity

Abdelghani Henni, *JPT* Middle East Editor



A QP condensate refinery complex under construction in Ras Laffan, the first condensate refinery in the Middle East.

Innovation and R&D have become top priorities for governments in the Middle East, mainly in the Gulf region. Qatar is striving to take the lead in this domain and has unveiled an ambitious plan to become the region's energy R&D center now that it has completed a massive liquefied natural gas (LNG) production upgrade as part of its strategy to monetize its vast gas reserves.

Qatar's plan to establish itself as a center of energy R&D is in line with its National Vision 2030, which aims to transform the nation from a hydrocarbon-based economy into a knowledge economy.

"R&D and technology have been at the heart of Qatar's energy sector for many years, allowing it to unlock and commercialize the North Field's vast gas reserves, and grow the country into the world's largest LNG exporter," said Hamad Rashid Al Mohannadi, chief executive officer of RasGas Company and chairman of the Board of Regents at Qatar University. He spoke recently at the Gulf Intelligence Qatar Energy R&D Forum in Doha in a presentation titled, "Qatar Energy R&D Next Steps—Moving from the Theoretical to the Specific."

"Going forward, they will continue to play an important role in ensuring the sustainability of our industry, whose economic support underpins the ambitious Qatar National Vision 2030," he said. "Qatar is blessed with a number of rooted establishments that enjoy strong financial backing to help set the direction for and facilitate these R&D and technology efforts. Our focus today should be on collaborating to effectively and efficiently address the grand challenges of energy, water, and cybersecurity."

Faisal Alsuwaidi, president of research and development at the Qatar Foundation for Education, Science, and Community Development, said that Qatar energy officials have identified 72 objectives for a research agenda, "all of them with targets for sustainable development to improve the quality of life."

Qatar has allocated 2.8% of its gross domestic product annually since 2006 to promote research, technology, and innovation.

With the country's near-term R&D focus on the areas of energy security, water security, and cybersecurity, nation-

al and international stakeholders from the government, industry, and academia have been meeting to align their strategies to address these "grand challenges."

Qatar Petroleum recently opened a research and technology center in the Qatar Science and Technology



State-of-the-art R&D facilities in Qatar focus on activities and technologies that secure sustainability in upstream oil and gas activities.



A 600 MHz Bruker UltraShield NMR (nuclear magnetic resonance) spectrometer for liquids analysis at Qatar Science and Technology Park.

Park (QSTP). The center will focus on R&D needs for existing and new business opportunities. It is also designed to initiate, lead, and support initiatives toward acquisition, development, and retention of new knowledge that will deepen and broaden the technical capabilities of the company.

“The center’s current research and development priorities focus on activities and technologies that secure sustainability in the upstream activities of oil and gas operations,” said Mohamed bin Saleh Al-Sada, Qatar’s minister of energy and industry. “This covers production optimization, safe and efficient operations, asset integrity preservation, and environmental impact minimization, as well as downstream activities related to natural gas processing and treatment.”

International oil companies are expected to play a role in Qatar’s R&D rise. “With government, industry, and academia working together, we can all invest in tomorrow’s advanced technologies, and I can confidently say Qatar provides a prime example of R&D, innovation, and collaboration in action,” Bart Cahir, president and general manager of ExxonMobil Qatar, said at the forum. “We have been able to make full use of Qatar’s collaborative environment as we progress research efforts that are coordinated with vested stakeholders within the state of Qatar, including the Ministry of Environment and the Ministry of Municipality and Urban Planning.”

ExxonMobil scientists are currently investigating water treatment technologies that allow for the beneficial reuse of

treated industrial wastewater in operations. In November, Qatar Shell opened a water laboratory aimed at studying how to improve the efficiency of water treatment technologies.

In January, Maersk Oil launched a digital core laboratory that will support ongoing applied research efforts in enhanced oil recovery (EOR). The laboratory, the first of its kind in the Middle East, will support ongoing applied research particularly in carbonate reservoirs, such as Qatar’s Al Shaheen oil field, one of the most complex in the world. It is part of a 10-year, USD 100 million investment by Maersk in applied research in Qatar focusing on improved oil recovery and EOR and operating in marine environments.

The research also will have applications outside of Qatar, speakers at

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The Qatar Shell Research & Technology Centre focuses on how to improve efficiency of water-treatment technology.

the forum said. “Our work is focused on the development and implementation of technologies that support Qatar’s specific needs, as well as support Qatar’s

role as the world’s largest liquefied natural gas exporter and the gas-to-liquids capital of the world,” said Youssif Saleh, general manager of Qatar Shell Research

and Technology Centre in the QSTP. “But while it is important that R&D projects in Qatar take a specific interest in delivering solutions to local needs, it is important to realize that the technology developed and deployed in Qatar can be globally relevant and commercially attractive in the rest of the word as well.”

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On Track

A survey of attendees at the forum found that Qatar’s quest toward becoming a global R&D hub has progressed at a satisfactory pace over the past 12 months, but the Gulf state should now focus on further expanding educational capacity and encouraging more private sector engagement as part of its ambitions.

In the survey, 41% of respondents believe that Qatar should place a stronger emphasis on higher education in the short term and launch more PhD programs to advance its R&D plans, while 40% thought it would be most important to implement initiatives aimed at driving more private sector engagement to encourage entrepreneurship and create an innovative environment supportive of R&D. The remainder of respondents expressed the view that a greater emphasis should be placed on developing a regulatory framework that includes provisions for intellectual property rights. **JPT**



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A New Contract Between Management and the Petrotechnical Professional

Henry Edmundson, R9 Energy Consultants, and David Bamford, Premier Oil

The continued search for oil and gas relies in equal measure on good management and superior petrotechnical expertise. The key is ensuring that the two worlds mesh smoothly and create a working environment that motivates both parties to succeed. This is less obviously achieved than might be thought for a number of factors.

First is the scarcity of top-quality petrotechnical professionals (Fig. 1). This used to be blamed on the famous “crew change,” which described the paucity of recruits during the oil price crash of the 1980s. But things have now changed. The past few years have seen abundant recruiting by both operators and the service industry, and the crew change problem has morphed into the challenge of accelerating the development of thousands of young professionals to fill the still prevalent mid-career gap. The result is an industry obsessed with accelerating employee development.

Second is the market force generated by the continued lack of mid-career petrotechnical professionals.

These lucky individuals command a price in excess of their equivalent managers, and so even do the young aspirants joining their ranks. With the oil price robust around USD 100/bbl and global upstream activity buoyant, there remains an extraordinary lack of competent geoscientists, drilling engineers, and petroleum engineers. And they know it. Never has it been so easy to jump ship, hoping for a better future.

Third is the meeting point between management and the petrotechnical expert. Both obviously aspire to business success, but beneath broad corporate goals lurk important differences. In companies of any reasonable size, managements must ensure that their machine to find and extract oil and gas is properly assembled, well lubricated, and working to maximum efficiency. Standards and discipline are important; within well-defined limits, employees are expected to conform.

The technical expert, however, marches to a different tune, motivated by quite different criteria. When it comes to creativity and improving technical

knowledge, petrotechnical professionals prefer less rather than more management, or even no management. The ideal state is being self-directed; satisfaction comes from solving tough technical problems. When it comes to their career, peer recognition and involvement is as important as management input. In short and at risk of working an analogy beyond breaking point, the square peg that is the technical expert may not always fit the round holes of the smooth-running business machine. How to manage this less-than-exact fit requires some unusual strategies.

Let’s start with two management imperatives and then examine the details (Fig. 2).

First, in order to keep pace, managers need the brightest and best informed technical experts possible. This means ensuring technical employees have the right environment to develop new knowledge and skills, particularly in emerging technology areas, and not necessarily junior employees only. It also means that experts need free and easy exchange of knowledge and experi-

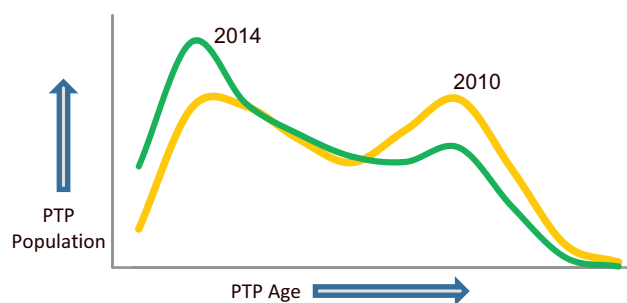
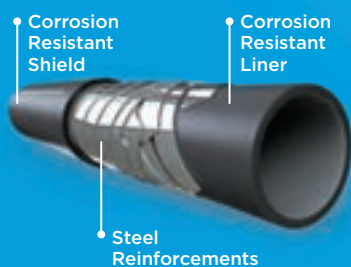


Fig. 1—The crew change challenge (2010) has morphed into the challenge of accelerating petrotechnical professional (PTP) development (2014).

Do's	Don'ts
<ul style="list-style-type: none"> Focus training on task at hand Emphasize total package Partner with petrotechnicals on technical ladder Devolve large chunks of knowledge management to petrotechnicals 	<ul style="list-style-type: none"> Cut training to shore up bottom line Let competency-driven training get too big Assume majority control of the technical ladder Attempt to manage tacit knowledge inside the organization

Fig. 2—Guidelines for management to the new contract.

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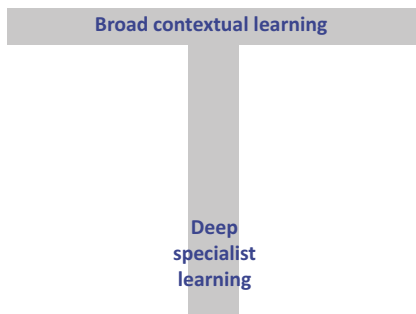


Fig. 3—The T-model challenge: how to strike the balance between in-depth vs. contextual development.

ence both from within and outside the company firewall.

Second, management needs to incentivize their technical experts not to leave for more enticing-looking employers. This can be achieved through a smorgasbord of options, including total compensation package, a technical promotion system or ladder, and satisfying the development needs mentioned above. Above all, management must provide strong leadership and ensure a coherent and attractive company culture.

Employee Development

Employee development is easy to wish for, harder to put into practice. There are several pitfalls. One is the traditional thinking that development is going on a weeklong training course once a year. Courses have their place, but are only one component of a development program. The other components include self-study—used to be done from books but now the Internet—on-the-job training, just like apprentices used to do, and learning from colleagues. Each training mode has its memory retention factor, and research shows that the classroom setting, although a key for getting basics across, does not rank high compared with self-study and repetitive hands-on experience.

Whatever the mix, two management temptations must be discouraged. The first is cutting employee training whenever business looks bleak. It is the easiest thing to cut since it never

impacts the short-term bottom line, but the long term is another matter. The second is believing that the return on investment of training and development can be measured and monitored. Training and development, by definition, is a long-term commitment, and it is as hard to quantify the benefits as it is to predict the success of R&D.

What management can insist on is focusing training and development on the job at hand, or at least what the employee is likely to be doing in the near future. Otherwise, training budgets quickly get eaten up, providing employees nice-to-know stuff rather than need-to-know essentials. The challenge is deciding what is truly necessary for the business. The oft-quoted T-model of training and development is a useful metaphor (Fig. 3). The vertical of the T represents in-depth specialist expertise, while the horizontal represents broad contextual understanding. How a company trains its employees depends very much on the importance attached to each at various stages of the technical expert's career.

Companies wishing to realize immediate earning power from young employees will focus on the vertical, allowing the horizontal to develop once the employee matures. Other companies prefer more contextual development before forcing the vertical. It is a matter of strategy, but it needs to be thought through.

There are concomitant choices for managing the employee's development. The vertical is best managed through curriculum-based programs, a linear progression of tasks and learnings to be checked off. The horizontal is best managed using a competency management approach that maps selected competencies and proficiencies to the job at hand. It risks becoming a large sledge hammer to crack the nut, but the idea does offer flexibility and the option to tailor training programs to large numbers of diverse employees. However, competency management comes with a health warning. The systems quickly get heavy,

require employee assessments, and are difficult to maintain. The trick is to keep things simple.

Another training imperative is coaching, an idea handed to us from ancient times when young people learned from a master. It has been unambiguously proven in recent studies that good coaching provides the most efficient catalyst for accelerating employee learning. However, most companies struggle with the same basic conundrums. The coaching role needs careful definition, otherwise it ends up meaning whatever the participants decide. It is also expensive because valuable time is required from senior technical experts, and in today's world, there are simply not enough senior experts to go round. Some companies contract retired experts to provide the coaching, but this risks diluting company culture. Coaching is worth every penny, but there are no cookbook recipes.

Knowledge Management

Knowledge is essential for any business, not least for satisfying a technical expert's ability to keep in touch with everything that is new. Technical knowledge in the business context can be divided between knowledge accessible from public sources and knowledge that is retained behind the firewall because it is deemed proprietary or confidential. Accessing the former is a purely mechanical task, revolutionized in the past decade by the Internet. Managing the latter is harder because the company itself must create the mechanisms. This management of internal technical knowledge is divided into two main parts.

One is explicit knowledge gained from company activities that must be validated, cataloged, and made available internally. The other is so-called tacit knowledge that is in the heads of the technical experts and only gets shared in conversation, either in person or through the intranet. Sharing tacit knowledge is primarily a social activity. It works best when there is no inter-

ference from management; they would simply get in the way. The challenge for most companies is stretching the culture enough so employees can share their tacit knowledge with zero control. When it began, this type of activity was called communities of practice, but what it has become is just a typical social media activity such as LinkedIn or Facebook, but restricted inside the company.

Incentivization and Careers

Given the continued shortfall in experienced petrotechnical professionals, both operators and the service industry are fighting for talent. For the professionals, the money offered can be tempting and occasionally extravagant, to the point where it is impossible for any company to compete on an ongoing basis. What companies can do, however, is to ensure that their employees understand the total remuneration package, comprising salary, bonus, housing and travel benefits, pension, and so on. The details are rarely understood by the employee or even enumerated by the employer. But the analysis is worth it, because it is the only way the employee can make a long-term comparison with offers on hand (Fig. 4).

The best incentive for petrotechnical professionals is a good career. Time and again, studies have shown that employees jump ship because of career dissatisfaction. This covers a multitude of sins, but a few basics cannot be argued with.

One is the need for status within the company. The company, in which the management line remains the only path to the top, risks losing its technical talent. The company with a secure technical ladder tied to a well-defined compensation scale will have no such worries. But given the number of failed attempts in our industry, the question is how to create a technical ladder that both management and the petrotechnical professionals believe in. Two issues are key: the ladder must be jointly owned and managed by both management and the technical community, and

the criteria for a technical promotion must address in equal part both business needs and technical requirements.

Another basic is the well-known fact that many employees quit because they can no longer tolerate their boss or some other irritant close by. This is hard for management to pick up on, but can be avoided by careful monitoring of employee dissatisfaction. In the last analysis, the employee is as responsible for his or her career as the employer is. Both make choices. The challenge is to create the best possible dialogue.

A New Contract

The oil and gas business continues on its technology journey and petrotechnical professionals provide the know-how. But they will remain in short supply for at least another decade. In the main, managers and technical professionals are cut from a different cloth, so a company's prerogative is to ensure that their respective talents compliment rather than compromise each other. Contrary to traditional practice, lot can be gained

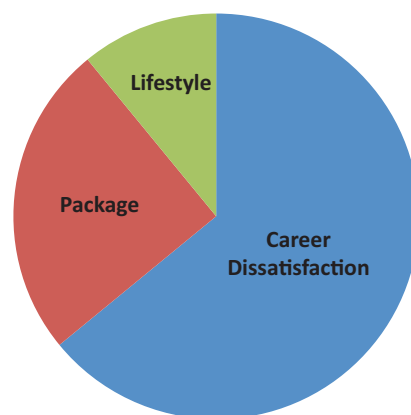


Fig. 4—Typical reasons for petrotechnical professional changing employer.

by an emphatic sharing of responsibility in key areas such as careers, training and development, knowledge management, and status for the technical professional. For the younger generation, especially, this is just plain common sense. For companies that have adopted this philosophy, it has paid huge dividends. **JPT**

Henry Edmundson is a director of R9 Energy Consultants, consulting in upstream strategy, communication, and technical capability. Previously, he worked for Schlumberger. His career there spanned 46 years starting with assignments as a wireline field engineer, interpretation development engineer, and research petrophysicist. He then became the founding editor of the Schlumberger Oilfield Review and a corporate speech writer. For the past 15 years, he oversaw the development of several global programs for the company's several thousand-strong petrotechnical professionals, including communities of practice initiative, the company's technical ladder, and a competency-driven training and development program. He is an active member of SPE, the Society of Petrophysicists

and Well Log Analysts, and the European Association of Geoscientists and Engineers. He is coauthoring a comprehensive history of upstream technology development.

David Bamford retired from BP in 2003 after a 23-year career that included years as a chief geophysicist and later as head of exploration, overseeing the recruitment, development, training, and motivation of geophysicists, geoscientists, and explorers. He also recently retired from Tullow Oil after 10 years as a nonexecutive director, serving as both senior independent director and chair of the Remuneration Committee. He is now a nonexecutive director at Premier Oil. He also cofounded Finding Petroleum, an events and media company.

William Bailey, SPE, works at Schlumberger-Doll Research as a principal engineer with 25 years of industry experience. His main technical interests include reservoir engineering, modeling of unconventional assets, multiphase flow in conduits, equipment-failure analysis, and computationally expensive optimization problems including coupled full-field assets. Bailey holds M.Eng. (Hons.) and PhD degrees in petroleum engineering from Imperial College, London, and the Norwegian University of Science and Technology, respectively, and an MBA degree from Warwick Business School. He was chairperson of the SPE New York and New England section and review chairperson for *SPE Production & Operations*, and he received the inaugural SPE A Peer Apart award. Bailey reviews for various SPE journals and serves on the *JPT* Editorial Committee and the SPE Books Committee.

Recommended additional reading at OnePetro: www.onepetro.org.

OTC 24913 Improved Numerical Simulation for Shale Gas Reservoirs
by Chaohua Guo, Missouri University of Science and Technology, et al.

SPE 164528 Analytical and Numerical Solutions for Multiple Matrix in Fractured Reservoirs: Application to Conventional and Unconventional Reservoirs by Mehmet A. Torcuk, Colorado School of Mines, et al.

SPE 166375 Experimental and Numerical Analysis of Gas Transport in Shale Including the Role of Sorption
by K.R. Alnoaimi, Stanford University, et al.

SPE 165409 Streamline-Based Coupled Geomechanics and Reservoir Simulation for Hydromechanical Modeling of CO₂ Storage in Saline Aquifers
by Behrooz Koohmareh Hosseini, University of Alberta, et al.

RESERVOIR SIMULATION

As the development of shale oil and gas becomes increasingly significant, so does the need for modeling tools for their accurate and timely forecasting. The basic question then arises: Are the simulation tools that we have suitable for the job? Can they explain, and ultimately forecast, the contribution to flow from natural or hydraulically induced fractures? Ultimately, we need to be confident that the results from such models are sufficiently reliable for decision-making purposes. As Alexandre Emerick stated in *JPT* (April 2014), “The goal is to generate models for production forecasting aiding the decision-making process involved in the development and management of petroleum reservoirs.”

The ability to model this increasingly important asset class is one of the primary issues facing reservoir and simulation engineers today. Our existing arsenal of simulation tools is certainly time-tested for conventional assets, but can they deliver reliable forecasts for this emergent class? Recent literature is rich with relevant studies ranging from fundamental laboratory experiments to entirely empirical, data-driven, approaches for predictive reservoir management. These articles raise numerous questions, including the possible oversimplification of a complex problem, the very nature of the production mechanisms, and the role played by any pre-existing discrete fracture networks.

Additional concerns relating to accuracy and reliability of the underlying data used to populate such models have also been raised. Keeping an open mind on this topic is, I feel, appropriate. One needs to balance the very real need for such predictive tools today with the recognition that future evidence may disrupt certain preconceptions. To this end, four articles have been selected that span a spectrum of ideas. One considers practical applications and solutions, while another covers the emerging technique of molecular simulation. Another eloquently probes various notions in our current state of understanding of shale assets and examines issues in interpreting the forecasts furnished by our simulation models. The fourth article demonstrates some creative thinking by representing a planar fracture by use of a proxy comprising a coupled flowing network model, a concept that may prove flexible and warrants further investigation.

Conventional modeling tools used to predict flow in tight, fractured shales (e.g., dual-porosity models, local grid refinements, tartan grids) may, indeed, provide reliable forecasting. Analytic and data-driven approaches are also acceptable in some circumstances. However, as our knowledge in exploiting these assets deepens with new theory, laboratory experiments, and field and operational experience, we should be prepared to reconsider some of today's axioms in the future. **JPT**

Factors Critical to Multiwell Reservoir Simulation of Liquids-Rich Shale Plays

Multiwell modeling of shale plays is not performed frequently, mainly for two reasons: The requirements to capture the behavior of multiple horizontal wells with multiple hydraulic fractures could be computationally prohibitive, and the wells in extremely-low-permeability formations would have minimal interaction. Production data collected from shale plays, however, have shown that horizontal wells may interfere with each other during production. Therefore, in projects in which a main objective is well spacing or completion optimization, a comprehensive multiwell reservoir-simulation study is required.

Introduction

Single-well reservoir modeling has been used extensively to perform reservoir simulation in shale formations. In the appraisal phase of liquids-rich shale (LRS) reservoir systems, more detail may be required to capture petrophysical and stratigraphic features that can potentially affect production performance. During this phase, single-well conceptual models with a certain degree of detail can be sufficient for modeling purposes and economic analysis. However, if the presence of geological features (e.g., faults, fracture corridors, contrast of areal and vertical distribution of natural-fracture intensity) is believed to affect the economic evaluation of a certain area of interest, then a more-detailed geological model is required and multiple wells may have to be incorporated in the models.

Performing multiwell, or sector, modeling of shale formations can present several challenges:

- ▶ An adequate description of permeability and water saturation may be difficult to attain because the original values are considerably altered in the stimulated-rock-volume (SRV) region after the fracturing treatments.
- ▶ The capture of the transient flow observed in LRS formations and the large pressure gradients around the fracture planes requires extensive grid refinement.
- ▶ The large drawdown necessary to produce from these ultralow-permeability formations can make pressure/volume/temperature (PVT) sampling a poor representation of the original reservoir conditions.
- ▶ The interaction of hydraulic fractures with natural fractures or the development of fracture networks can be very difficult to model.

Seismic

The application of seismic for reservoir simulation of LRS plays goes beyond the classical reservoir-simulation workflow; seismic processing, inversion, and interpretation can provide important reservoir-property distributions that are key parameters for reservoir simulation and production analysis.

A variety of seismic attributes can be used to predict the intensity and orientation of probable pre-existing natural fractures and the correlation with microseismic responses. This can be used to build discrete-fracture-network (DFN) models and patterns of hydraulic-fracture propagation and interaction with natural fractures and to constrain the SRV size and shape.

Acoustic impedance can be used to generate porosity and pore-pressure distributions within a target shale region. The logic is that acoustic impedance is a linear function of density, and density can be correlated with porosity from a petrophysical model.

Seismic interpretation calibrated with rock-property models is also used to provide rock-property distribution in a specific area to constrain and validate production from reservoir-simulation models.

PVT Sampling and Analysis

The extremely low permeability of shale formations requires large drawdowns to produce hydrocarbons commercially, and, typically, the early production at the lowest possible drawdown is nearly 100% water, recovered from the fracturing treatment. The large drawdowns applied also produce significant liquid losses, especially in the volatiles/condensate window; therefore, the low liquid recovery is strongly dependent on PVT behavior.

In that situation, one possible solution is to combine advanced PVT modeling with single-well reservoir simulation to match production performance using fluid initialization parameters as key history-matching variables.

Cartesian Grids, Tartan Grids, and Unstructured Gridding

The production behavior from shale formations can be in transient flow for

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 169025, "A Study of Dynamic and Static Factors That Are Critical to Multiwell Reservoir Simulation of Liquids-Rich Shale Plays," by Carlos Miranda, SPE, and Huade Yang, Marathon, prepared for the 2014 SPE Unconventional Resources Conference—USA, The Woodlands, Texas, USA, 1–3 April. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.



Fig. 1—Simulated connected fractures.

months or years because of the extremely low matrix permeability. When hydraulic fractures are placed in the formation, the flow regimes can vary from linear flow to bilinear flow in the first months or years until the pressure transient reaches determined boundaries (fracture-stage boundaries, boundaries at the tips of the fractures, or reservoir boundaries) after several years of production. The hydraulic fractures introduce large pressure gradients at the fracture faces and tips because of the large contrast between the matrix and fracture permeabilities. Therefore, special grid refinement is required around those regions in order to capture the characteristic flow regimes.

Cartesian Grids With Local Grid Refinement (LGR). LGR can be applied around the main hydraulic-fracturing planes in order to capture transient flow. This approach adds more cells, increasing the running time; however, it is relatively simple to implement and can make the incorporation of SRVs from microseismic interpretation easier.

Tartan Gridding. In a tartan grid, the cells are globally distributed in the reservoir following a logarithmic or geometric propagation around the fracture planes, fracture tips, and well lateral length. This gridding type is a preferred method because it allows for the capture of transient flow properly and for optimization of the number of cells, reducing running time. However, the process of building tartan grids for multiwell modeling can be very laborious because

of a lack of this capability in most of the geomodeling software packages currently available.

Unstructured Gridding. Unstructured gridding is the ideal gridding method because it solves all the issues related with nonparallel laterals and nonorthogonal fracture planes; and it fits very well with complex fracture simulators because it captures complex fracture geometries. However, this type of gridding requires important reformulation of flow modeling, and most commercial reservoir simulators do not have this capability fully implemented yet.

Hydraulic-Fracturing Modeling

Hydraulic-fracturing modeling is not commonly included within conventional reservoir-simulation workflows. However, for reservoir-simulation studies of shale formations, a fair understanding of the propagation of hydraulic fractures and their interaction with pre-existing natural fractures should be considered an integral part of the reservoir-simulation workflow in order to estimate or constrain the size and shape of the SRV.

Some simulators with the ability to predict the propagation of complex fracture networks have been released commercially. These simulators have capabilities to build DFN models or can import DFN models from geomodeling software packages. The first approach uses classical linear elastic approaches to model the propagation of the hydraulic fracture from its initiation and vertical propagation into surrounding layers or into

natural fractures. The interaction with the natural fractures is modeled on the basis of propagation of fracturing-fluid pressure and leakoff into the connected natural-fracture system. This propagation model is constrained by the state of in-situ stresses, the orientation and geometry of the pre-existing natural-fracture system, rock properties, and the interpretation of microseismic monitoring (Fig. 1). The second approach models the fracture propagation, fluid flow, and proppant transport in a complex fracture network. The interaction between the created hydraulic fracture and the pre-existing natural-fracture system is modeled with an analytical model that also considers the mechanical interaction with adjacent fractures as a result of multistage fracturing (Fig. 2). Although this method currently is limited to single-well modeling, it can provide a relatively good understanding of the size and shape of the SRV.

Microseismic Monitoring

Microseismic events are seismic energy released from shear failures away from the hydraulic fracture and along reactivated/induced natural fractures, if they are present. Therefore, microseismic monitoring frequently displays a broad cloud of microseismic events that is not necessarily associated with connected complex fracture networks.

A complex fracture network follows the physical interaction of the hydraulic fractures with the pre-existing natural-fracture system, and its development is conditioned by the state of the in-situ stresses (maximum and minimum horizontal stresses), the orientation and geometry of the natural fractures, rock properties, fluid properties (e.g., pressure and rheology), and the natural-fracture interface properties (e.g., friction coefficient, cohesion, and permeability).

When properly interpreted and combined with geomodels and production performance, microseismic monitoring can be a very useful tool for multiwell spacing and hydraulic-fracturing optimization.

Proposed Reservoir-Simulation Workflow

Fig. 3 presents a workflow to help in the process of multiwell reservoir simula-

tion for LRS formations. This workflow presents some departures from the classical reservoir-simulation workflow for conventional reservoirs. Shale characterization, complex-fracture modeling,

and microseismic interpretation have been incorporated to address the effect of several static and dynamic factors that are critical for reservoir simulation of LRS formations.

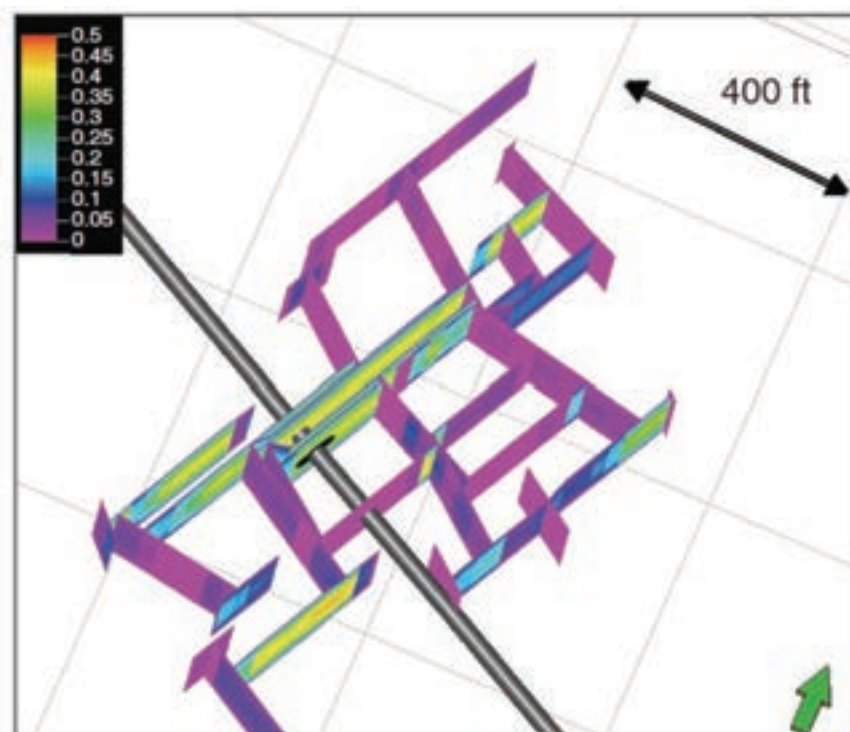


Fig. 2—Fracture width from simulated complex fracture network.

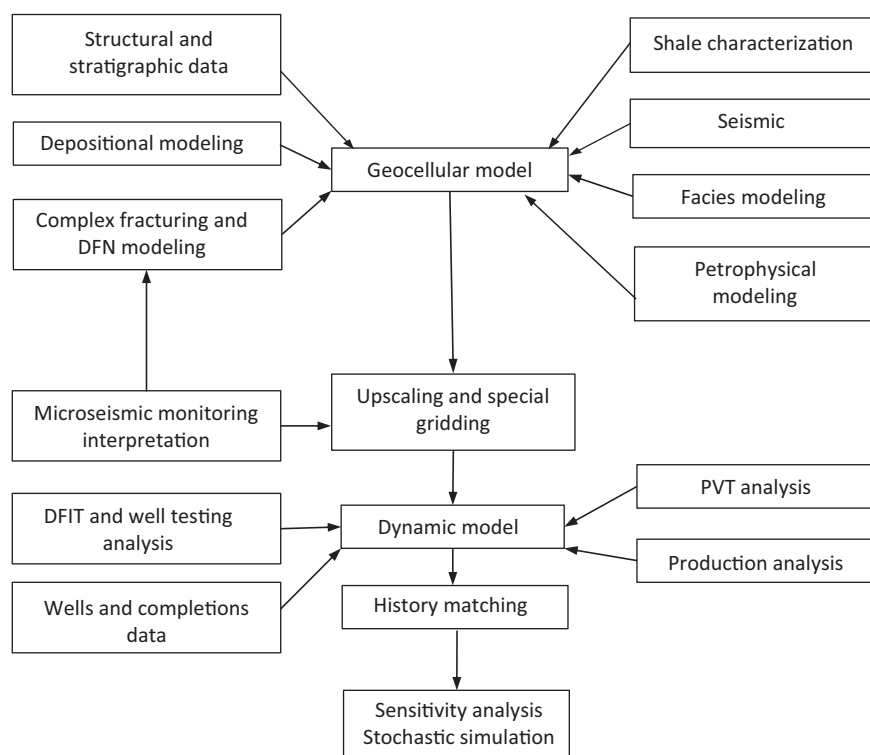


Fig. 3—Proposed reservoir-simulation workflow. DFIT=diagnostic fracture injection test.

Conclusions

- ▶ Multiwell (sector) reservoir simulation can be performed with some acceptable degree of confidence with adequate modeling (or a fair understanding) of the propagation of hydraulic fractures in the shale formation.
- ▶ Although conceptual models can be used in many cases, a more-detailed geological description may be required for well-spacing and fracture-stage-spacing studies when geological features are believed to affect the production performance.
- ▶ PVT analysis and modeling are critical for the simulation of LRS formations.
- ▶ The reservoir-simulation workflow for LRS formations should incorporate shale characterization, complex-fracturing and DFN modeling, and microseismic-monitoring interpretation.
- ▶ Shale characterization plays an important role in the reservoir-simulation process of LRS formations because it provides important insights to constrain and guide the building process of the geocellular and reservoir-simulation models.
- ▶ The characteristic transient flow of these formations requires special gridding features. This can be a very complicated task for multiwell modeling in some of the commercial geomodeling software packages. However, this can be accomplished by use of external applications for tartan gridding or by use of more-sophisticated unstructured-gridding capabilities when available.
- ▶ Although this can be considered a simple basic observation for conventional reservoirs, the formation thickness or the ratio of fracture height to formation thickness is a critical factor for reservoir simulation of LRS formations. **JPT**

Molecular Simulation Helps Determine Key Shale-Gas Parameters

Shale gas is fast becoming a source of energy of paramount significance for the coming years. Although commercial production has been achieved in numerous plays throughout the world, the actual physics involved is poorly understood. Molecular simulation is an emerging technique that can be put to use for shale gas. It offers insights into nanoscale properties such as sorption or transport coefficients. The technique is based on numerical simulations at the molecular scale for a given set of pressure and temperature conditions.

Introduction

Comprehensive organic-shale rock characterization performed in recent years has emphasized the dual nature of the porous system, which is split between organic and inorganic pores, each system having its own scales and associated physical properties. At least two clearly identified mechanisms are likely to cause composition changes over time: In tiny pores, where specific surfaces are huge with respect to volumes, gas exists in both free and condensed (adsorbed) states and in different compositions. Because free and adsorbed gas will not be produced at the same time in a well's life because the process is pressure dependent, a change in the produced-gas-composition stream is likely. In addition, flow through the nanometer-scale pore system exhibits not a Darcy pattern but a diffusion type of flow (transitional or free molecular flow) where transport coefficients

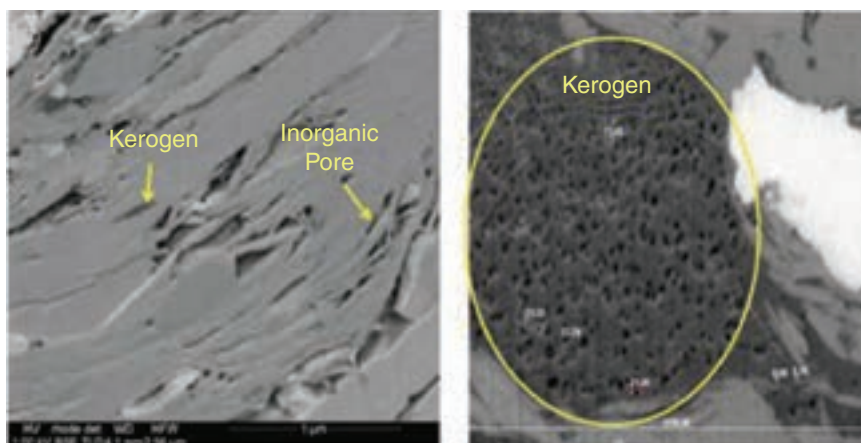


Fig. 1—Focused-ion-beam scanning-electron-microscope imaging shows highly porous kerogen.

depend on the molecule size. This mechanism is well-known in gas chromatography as molecular sieving and also will result in composition changes.

This paper seeks to offer a comprehensive screening of the current means available for representing such effects and to examine their consequence on long-term production with an appropriate model.

Pore-Network Structure in Organic Shales

One of the more remarkable features of shale-gas matrix is that it hosts kerogen, whose intrinsic porosity depends upon maturity. Focused-ion-beam scanning-electron-microscope images (Fig. 1) from the Barnett shale in the high-maturity window have shown that porosity can be as high as 30 to 40%. These observations were found to be consistent with previous evidence of strong corre-

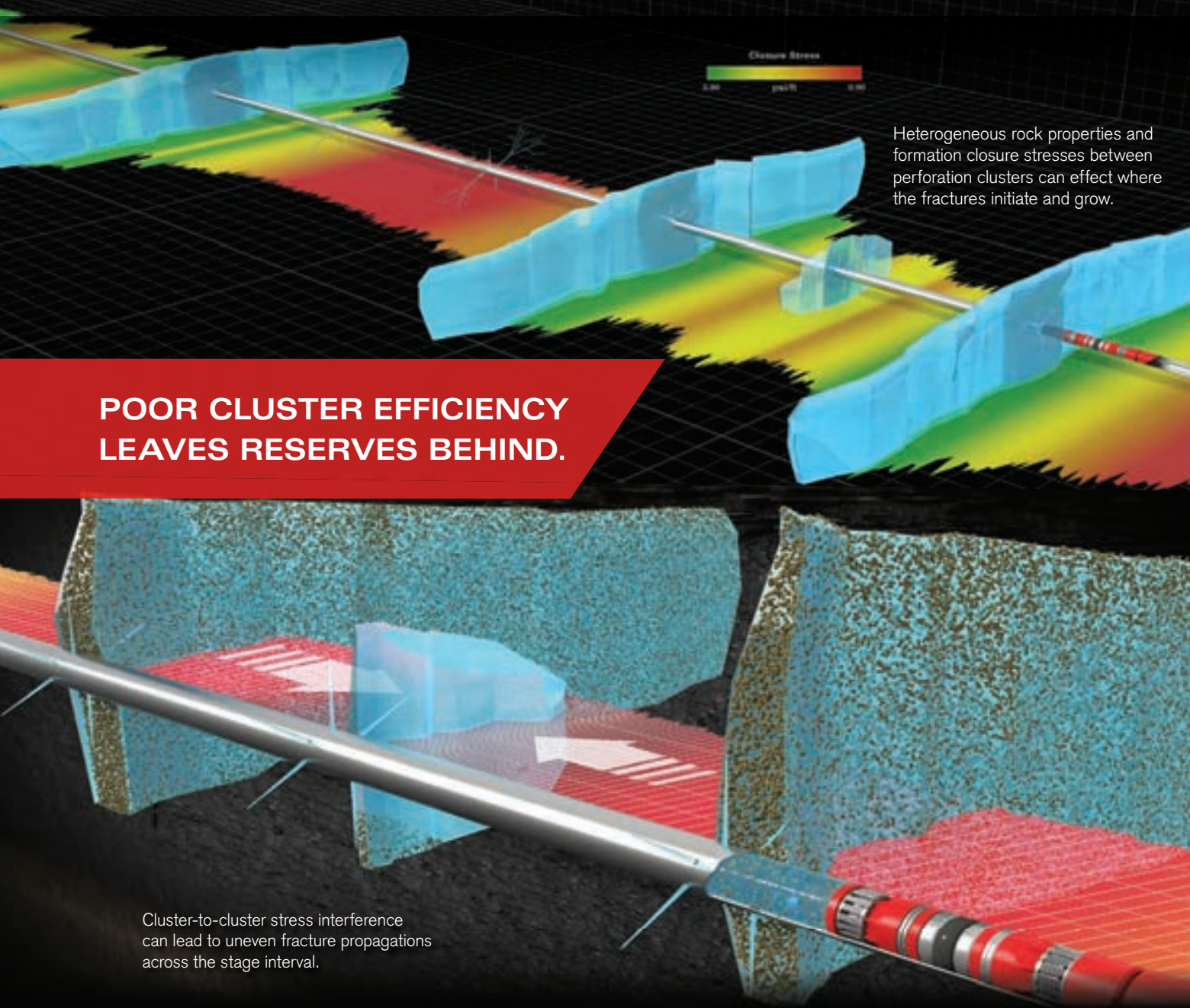
lations between gas-filled porosity measured on core samples and total organic content. They provide a means of quantitatively assessing the gas volume split between organic and inorganic pores, which is found to be 80:20 in the Barnett. This figure may vary from one play to another and may be highly dependent on maturity but is considered representative of the high-maturity Barnett shales. Another interesting observation drawn from these images is that kerogen nodules are scattered within the inorganic matrix, which therefore should provide the connectivity for the gas to flow to the well. A large range of inorganic pore types has been observed on images, but all of them support a step change compared with the organic pores (i.e., sub-microns vs. a few tens of nanometers). While physics is thought to remain conventional for the former, it will become much more complex for the latter: Adsorbed gas will mostly thrive in the organic pores where flow will be of a more diffusion-transport type.

Nanophysics Modeling for Shale Gas

Storage. The quantity of adsorbed gas that can be held by the rock at a given

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 164790, "Molecular Simulation To Determine Key Shale-Gas Parameters and Their Use in a Commercial Simulator for Production Forecasting," by F. Gouth, Total; J. Collell and G. Galliero, Université de Pau and Pays de l'Adour; and J. Wang, École Centrale de Pékin, prepared for the 2013 SPE Europec/EAGE Annual Conference and Exhibition, London, 10–13 June. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.



Heterogeneous rock properties and formation closure stresses between perforation clusters can effect where the fractures initiate and grow.

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Cluster-to-cluster stress interference can lead to uneven fracture propagations across the stage interval.

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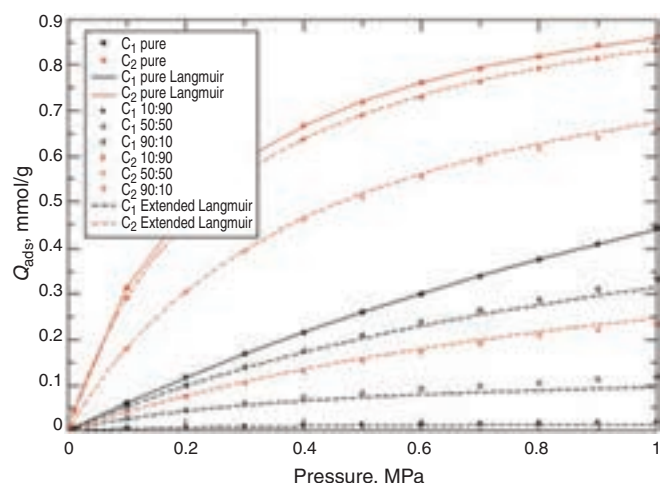


Fig. 2—Adsorption results on kerogen models considering sensitivities to the dummy Lennard-Jones particle radius of 11 Å.

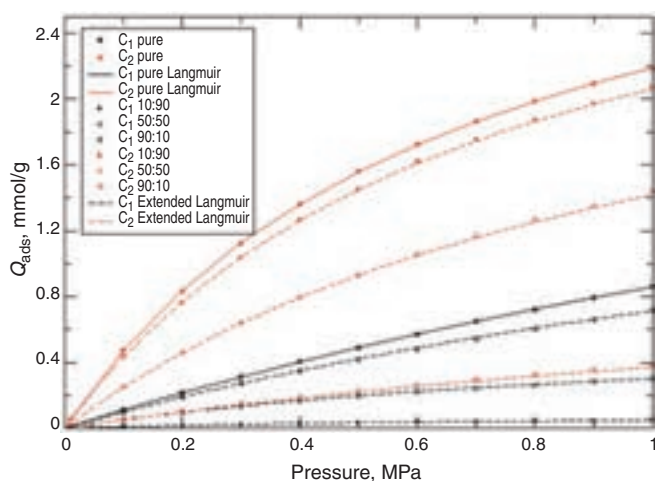


Fig. 3—Adsorption results on kerogen models considering sensitivities to the dummy Lennard-Jones particle radius of 17 Å.

pore pressure is well-represented by the Langmuir-isotherm model. For gas mixtures, the extended-Langmuir formulation, an extension of the single-component Langmuir, is widely used. Please see the complete paper for the equations.

Transport. Darcy's law has been used extensively for oil- and gas-flow modeling in a porous medium. It is well-suited for transport through mesopores, whose permeability ranges from the milli- to the microdarcy level, but it fails to predict transport in tight structures such as shales, where diffusional effects can no longer be neglected compared with viscous effects. Pores in these shales typically range from a few angstroms to tens of nanometers. Under such conditions, slippage at the solid/fluid interface cannot be neglected. As the pore size decreases, the flow shifts from no-slip (Darcy) to slip, then to transition and to free molecular flow. The Beskok-Karniadakis (BK) model is a unified formulation designed to represent all types of flow. It is based on a correction factor modifying the permeability, which relies on the Knudsen number. The BK model, therefore, affords insight into the deviation of the flow from the Darcy mode.

Molecular Simulation

Molecular simulation is a compelling computing technique that was investigated as a means to check the reliability of the extended Langmuir and BK analytical models, and it turned out to be essen-

tial in highlighting their shortcomings. It, therefore, looks to be a very promising way of providing matrix properties in place of laboratory experiments.

Principle of Molecular Simulation.

Today, molecular simulations are not only applied to conceptual systems but also can simulate actual material properties. The authors used both Monte Carlo (MC) and molecular-dynamics (MD) simulations to assess adsorption isotherms in the kerogen and the transport properties of fluids through a slit pore.

MC Simulation of Adsorption.

MC simulation is a statistical method for studying the thermodynamic equilibrium state by considering only atom locations and, thus, does not allow for assessing transport properties directly. It is still well-suited to quantify adsorption in a microporous structure. Calculations are performed in the grand canonical (GC) statistical ensemble by imposing chemical potential, volume, and temperature. The main assumption of MC simulations in the GC ensemble—made to reduce computational time by eliminating the necessity of computing solid/solid interactions—is that the kerogen molecules are rigid.

MD Simulation. Contrary to MC simulation, MD is a method used to assess the dynamic properties of the system. It simulates the system's evolution over time by integrating the classical equation of motion, giving the positions, velocities, and accelerations of each particle in the system.

Molecular-Simulation Results

Prediction of Binary-Mixture Adsorption by Use of the Extended Langmuir Model. The consistency of the extended Langmuir formulation has been checked by comparison with outcomes from molecular simulations. The process entailed the following steps:

- 1 Assessment was made of the Langmuir pure-component adsorption capacity for methane and ethane.
- 2 Estimated volume and pressure parameters were then used to compute the coadsorption capacity for different-concentration mixtures with the extended Langmuir model.
- 3 Mixture coadsorption was simulated by molecular simulation.
- 4 The results were compared with those from the extended Langmuir model.

Comparisons are given first for the low pressure range (0.01 to 1 MPa) and then for a high pressure range (up to 20 MPa). The temperature considered was 338 K.

At Low Pressures. Figs. 2 and 3 show the adsorption results on kerogen models that consider sensitivities to the dummy Lennard-Jones particle radius (11 and 17 Å, respectively). The dots represent the molecular-simulation results for pure components and mixtures. The solid lines represent the Langmuir-model match on the pure-component molecu-

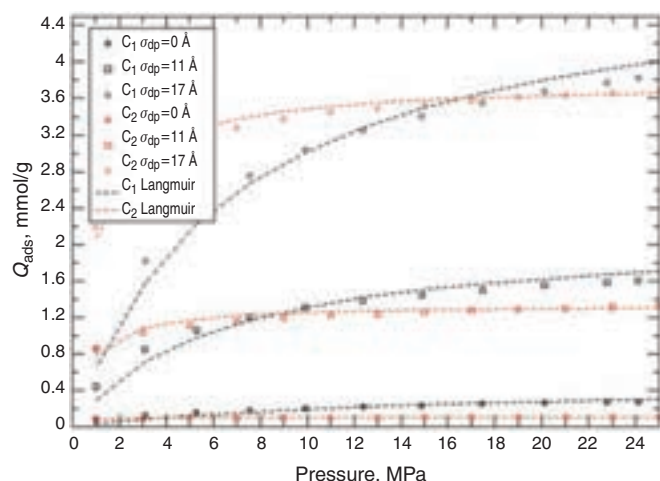


Fig. 4—Comparison of extended-Langmuir-model outcomes with the molecular-simulation results for the 11-Å dummy particle sizes.

lar simulations for volume and pressure identifications. The dashed lines represent the extended-Langmuir-model forecast based on each component's volume and pressure for the different mixtures.

Comparisons between the extended Langmuir model and molecular simulation on mixtures emphasize the effectiveness of the former, at least for the low range of pressures considered.

At High Pressures. The pressure range was widened to 20 MPa. Figs. 4 and 5 compare the extended-Langmuir-model outcomes with the molecular simulation results for the 11- and 17-Å dummy particle sizes, respectively.

There is an evident deviation of the extended Langmuir model (dashed curves) from the synthetic real data (molecular-simulation output), whereas no such deviation was observed at lower pressures. There is no obvious explanation for the discrepancy, but one possible explanation is that gas mixtures do not follow ideal behavior at high pressures.

In Figs. 2 and 3, dashed lines represent the conventional extended Langmuir model (as a function of partial pressures), while mixed dashed lines represent an enhanced extended Langmuir model. As can be observed, the new extended Langmuir model improves the forecasting capability. The authors strongly recommend implementation of such models in future commercial reservoir simulators.

Application of Molecular Simulation to the BK Model. The authors considered a slit-pore geometry (defined by

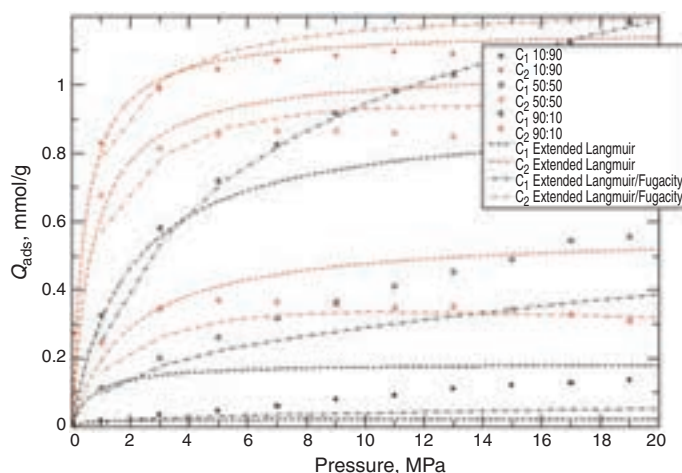


Fig. 5—Comparison of extended-Langmuir-model outcomes with the molecular-simulation results for the 17-Å dummy particle sizes.

pore width) and ran several simulations for pure gas and binary methane/ethane mixtures. They investigated the effect of both pore width and pressure. The simulation process involved the following steps:

- ▀ First, MD simulations in a GC-like ensemble were run: the slit pore was connected to two reservoirs at the two ends of the pore. The reservoirs were filled with fluid particles at the bulk density. Pressure and temperature were imposed in the reservoirs. This stage allows us to determine the fluid density in the pore at given thermodynamic conditions and pore size.
- ▀ Nonequilibrium MD simulations were then run in the slit pore, only at imposed temperature and density. The flow was controlled by imposing a gravitational force parallel to the solid walls.

Flow of Pure Methane Through the Slit Pores

The conclusion from the results was that, for the conditions typically encountered in shales and within the pressure range considered, the BK model correctly predicts mobility in the wide pores (approximately 78 Å) but gives only qualitative values for narrower pores.

Conclusions

- ▀ Molecular simulation has been investigated as a

means to provide actual parameters that would be difficult to obtain experimentally. It has been used to challenge analytical formulations developed for both storage (extended Langmuir model) and transport (BK model) in a nanoporous medium.

- ▀ The extended Langmuir model looks ill-suited to represent coadsorption for binary gas mixtures (C_1/C_2). However, it would be possible to improve the model by replacing partial pressure with fugacity in the formulation.
- ▀ The BK model provides a fair estimation of pure-gas mobility in an ideal porous medium but is ill-suited for binary gas mixtures (C_1/C_2) at high pressures. One of the main pitfalls is the way dynamic viscosity should be determined.
- ▀ With the base-case-model parameters and the nanoscale-properties input modeled with the extended Langmuir and the BK model, the trend (but not the magnitude) of the composition changes was captured. This emphasized the need for additional work to be carried out to determine complex-gas-mixture properties by use of molecular simulations. **JPT**

A Critical View of the Current State of Reservoir Modeling of Shale Assets

The coupling of hydraulic fractures and natural-fracture networks and their interaction with the shale matrix remains a major challenge in reservoir simulation and modeling of shale formations. This article reviews methods used to understand the complexities associated with production from shale to shed light on the belief that there is much to be learned about this complex resource and that the best days of understanding and modeling how oil and gas are produced from shale are still ahead.

Introduction

Preshale Technology. The phrase “preshale” technology aims to emphasize the combination of technologies that are used to address the reservoir and production modeling of shale assets. In essence, almost all of the technologies used today for modeling and analysis of hydrocarbon production from shale were developed to address issues that originally had nothing to do with shale. As the shale boom began, these technologies were revisited and modified in order to find application in shale.

Conventional Discrete Fracture Network. The most common technique for modeling a discrete natural fracture (DNF) network is to generate it stochastically. The common practice in carbonate and some clastic rocks is to use borehole-image logs to characterize the DNF at the wellbore level. These estimates of DNF characteristics are then

used for the stochastic generation of the DNF throughout the reservoir.

The idea of the DNF is not new. It has been around for decades. Carbonate rocks and some clastic rocks are known to have networks of natural fractures. Developing algorithms and techniques to generate DNFs stochastically and then couple them with reservoir-simulation models was common practice before the so-called “shale revolution.”

A New Hypothesis on Natural Fractures in Shale

What are the general shapes and structures of natural fractures in shale? Are they close to those of the stochastically generated set of natural fractures with random shapes that has been used for carbonate (and sometimes clastic) formations? Or are they more like a well-structured and well-behaved network of fractures that have a laminar, plate-like form, examples of which can be seen in outcrops (such as those shown in Fig. 1)?

Shale is defined as a fine-grained sedimentary rock that forms from the compaction of silt and clay-sized mineral particles commonly called mud. This composition places shale in a category of sedimentary rocks known as mudstones. Shale is distinguished from other mudstones because it is fissile and laminated.

If such definitions of the nature of shale are accepted and if the character of the network of natural fractures in shale is as observed in the outcrops, then many questions must be asked, some of which are

- ▶ How would such characteristics of the network of natural

fractures affect the propagation of the induced hydraulic fractures in shale?

- ▶ How would the production characteristics of shale wells be affected by this potentially new and different way of propagation of the induced hydraulic fractures (compared with how we model them today)?
- ▶ What are the consequences of these characteristics of natural fractures on short- and long-term production from shale?
- ▶ How would this affect current models?
- ▶ What can it tell us about new models that need to be developed?

Reservoir Simulation and Modeling of Shale

The current state of reservoir-modeling technology for shale uses the lessons learned from modeling naturally fractured carbonate reservoirs and those from coalbed-methane reservoirs. The combination of flow through double-porosity naturally fractured carbonate formations and the concentration-gradient-driven diffusion that is governed by Fick's law integrated with Langmuir isotherms that control desorption of methane into the natural fractures has become the cornerstone of reservoir modeling in shale.

The presence of massive, multicluster, multistage hydraulic fractures only makes the reservoir modeling of shale formations more complicated and makes the use of current numerical models even less beneficial. Because hydraulic fractures are the main reason for economic production from shale, modeling their behavior and their interaction with the rock matrix becomes one of the more important aspects of modeling storage and flow in shale formations.

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 165713, “A Critical View of Current State of Reservoir Modeling of Shale Assets,” by Shahab D. Mohaghegh, SPE, Intelligent Solutions and West Virginia University, prepared for the 2013 SPE Eastern Regional Meeting, Pittsburgh, Pennsylvania, USA, 20–22 August. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

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Fig. 1—Examples of natural fractures in shale are clearly observable from outcrops.

All the existing approaches of handling massive, multicluster, multistage hydraulic fractures in reservoir modeling can be divided into two distinct groups: the explicit hydraulic-fracture (EHF)-modeling method and stimulated reservoir volume (SRV).

EHF Modeling

EHF modeling is the most complex and tedious (as well as the most robust) approach for modeling the effect of hydraulic fracturing during numerical simulation of production from shale. The modeling technique couples three different technologies and consists of the following steps:

- ▶ Modeling the effect of the hydraulic fracture
- ▶ Developing a geological model
- ▶ Incorporating fracture characteristics in the geological model
- ▶ Completing the base model
- ▶ History matching the base model
- ▶ Forecasting production

SRV Modeling

SRV modeling is a different and much simpler way of handling the effect of massive, multicluster, multistage hydraulic fractures in numerical reservoir simu-

lation and modeling. Using SRV modeling instead of EHF modeling can expedite the modeling process by orders of magnitude. This is because, instead of meticulously modeling every individual hydraulic fracture, the modeler assumes a 3D volume around the wellbore with enhanced permeability as the result of the hydraulic fractures. By modifying the permeability and dimensions of the SRV, the modeler can now match the production behavior of a given well in a much shorter time.

The sensitivity of production from shale wells to the size and the conductivity assigned to the SRV explains the uncertainties associated with forecasts made with this technique. Although attempts have been made to address the dynamic nature of the SRV by incorporating stress-dependent permeability, the entire concept remains in the realm of creative adaptation of existing tools and techniques to solve a new problem.

Making the Case for Full-Field Reservoir Simulation and Modeling of Shale Assets

A quick look at the history of reservoir simulation and modeling reveals that developing full-field models (where all the wells in the asset are modeled together as

one comprehensive entity) is common practice for almost all prolific assets.

Looking at the numerical reservoir-simulation modeling efforts for shale assets, one cannot help but notice that almost all of the published studies are concentrated on analyzing production from single wells.

The argument to justify the limited approach (single well) to modeling of shale assets concentrates on two issues: the computational expense and the lack of interaction between wells because of the low permeability of shale. The argument about the computational expense is quite justified. Those who have been involved with numerical modeling of hydrocarbon production from shale can testify that modeling even a single well, which on the average includes 45 clusters of hydraulic fractures (15 stages assuming three clusters per stage), can be an extreme challenge to set up and run. If EHF modeling is used, the model can take tens of hours for a single run; therefore, building a geological model that would include details of every cluster of hydraulic fractures for an asset with hundreds of laterals is computationally prohibitive.

While the first reason (computation expense) seems to be legitimate and realistic, the second reason is merely

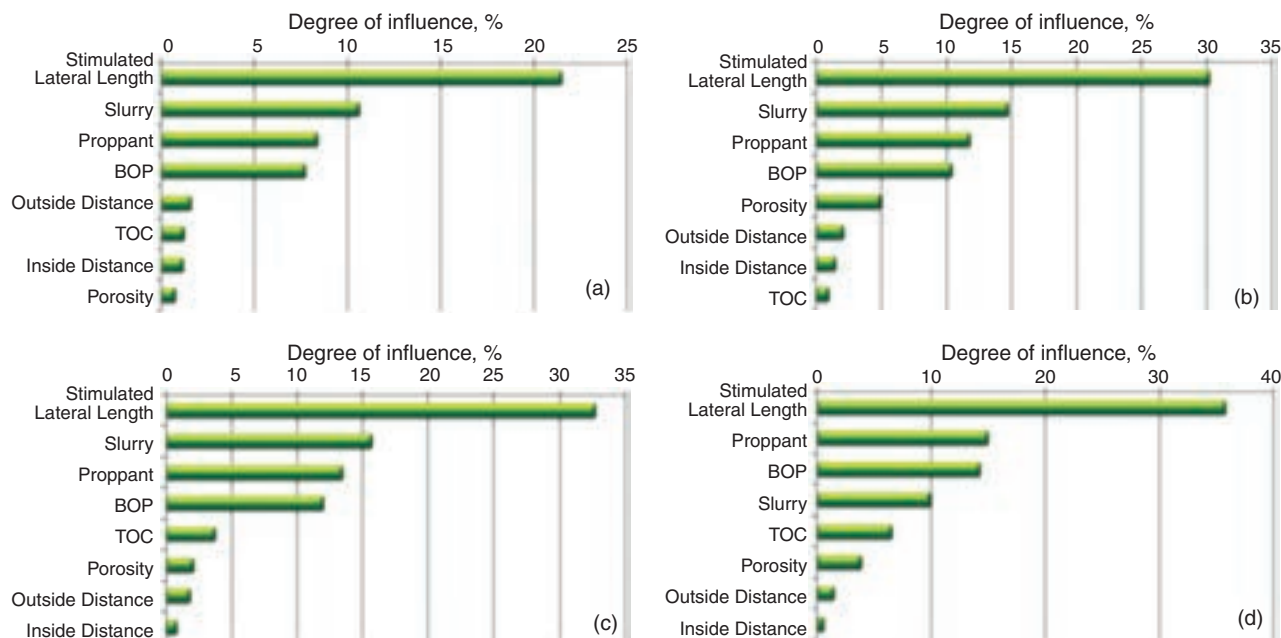


Fig. 2—Tornado charts show the effect of different parameters on gas production from a given pad. (a) After 3 months of cumulative production. (b) After 12 months of cumulative production. (c) After 21 months of cumulative production. (d) After 30 months of cumulative production. BDP=breakdown pressure; TOC=total organic content.

an excuse with limited merit. It is well-established that shale wells do communicate with one another during production. It has been shown that communication occurs between laterals from the same pad as well as the laterals from offset pads. The “frac hit” is a common occurrence of such interaction. A “frac hit” is when injected hydraulic-fracturing fluid from one well shows up at another well and interferes with its production.

Data-Driven Modeling of Production From Shale—An Alternative Solution

Because analytical and numerical full-field modeling of shale assets is either impractical or leaves much to be desired, data-driven modeling provides an alternative solution. Top-down modeling (TDM) is the application of predictive data-driven analytics to reservoir modeling and reservoir management.

TDM has been defined as a formalized, comprehensive, multivariate, and full-field empirical reservoir-simulation and modeling approach that is specifically geared toward reservoir management. In TDM, measured field data (and not interpreted data)—hard data—are used as the sole source of information to build a full-field model, treating and

history matching each well individually. This approach minimizes interpretation of the data and relies heavily on all that is known and measured in the field.

TDM uses the production history of each individual well in the asset along with wellhead pressure. The production data are augmented by all the hard data that are collected during drilling, logging, and completion of each well. All the parameters that are measured during the hydraulic fracturing are incorporated into the top-down model, such as type and amount of fluids that are injected, type and amount of proppants, and injection pressures and corresponding injection rates. The top-down model is history matched for every well in the asset. Once training, calibration, and validation of a top-down model are complete, its use is similar to that of conventional full-field models.

The final top-down model has a small enough computational footprint to allow for a comprehensive sensitivity analysis. Results of some of the sensitivity analyses performed on a specific pad are shown in **Fig. 2**. The advantages of using data-driven technology to perform reservoir modeling are

- No assumptions are made regarding the physics of the

storage and production of hydrocarbon in shale

- Hard data is used to perform modeling instead of soft, interpreted data
- Use of hard data instead of soft data makes it possible to use this model to design optimum fracturing jobs
- The small computational footprint allows for full-field analysis as well as sensitivity and uncertainty analyses
- More wells and more data make model development more reliable and more robust

The disadvantages of using data-driven technology include

- Not being able to explain explicitly the storage and transport phenomena in shale
- Data-driven modeling is not applicable to an asset with few wells (approximately 10 to 20 wells are required to start data-driven modeling)
- Long-term prediction of the production from a given well is not a simple and straightforward process. **JPT**

Technique Uses Multilateral, Multisegment Wells To Represent Hydraulic Fractures

Simulating fractured wells is challenging and impractical with local grid refinement (LGR) in full-field models with a large number of wells each with multiple fractures. This paper describes a modeling technique by which hydraulic fractures are represented as part of the well model rather than as any form of refinement in the simulation grid. In this approach, a planar fracture is modeled by the mesh formed from the interconnected branches of a multilateral, multisegment well (MSW).

Introduction

Hydraulic fracturing can dramatically change the flow dynamics of a reservoir, so its correct modeling in reservoir simulation can be critical. However, the presence of hydraulic fractures presents a challenge in flow simulation. This is because these fractures introduce effects that operate on different length and time scales than do usual reservoir dynamics.

To overcome this problem, a multitude of modeling techniques and workarounds has been developed. These include the use of dual-porosity models, enhancement of the productivity index of the fractured wells, virtual well perforations to simulate the fractures, and explicit fine-scale gridding.

In full-field simulations, where an entire reservoir with complex geometry, multiple wells, and possible faults is modeled, LGR is a popular method representing hydraulic fractures. How-

ever, this approach introduces its own set of problems. For example, in structured grids, the overall orientation of the grid may not easily accommodate fractures, particularly if they are at arbitrary angles.

This paper investigates the modeling of hydraulic fractures as part of the well model. MSWs are a discretized model of a well where fluid flow inside the wellbore is computed by solving physical flow model equations in one dimension. This domain is made up of the segments of the well that consist of nodes, which are connected by pipes. MSWs allow for lateral branches off the main stem and for looped flow paths; both features are employed here for the modeling of hydraulic fractures.

Hydraulic Fractures as Part of an MSW

Motivation. The idea behind this modeling approach is that hydraulic fractures become independent of the simulation grid. This means that multiple fractures per well and multiple fractured wells per reservoir can be modeled easily without constraints on orientation. Furthermore, there is no need to introduce small cells into the reservoir model and thus the reservoir model is concerned only with fluid flows on a large scale. Rapid fluid movement and rapid solution changes are localized to the well model, where these are commonplace and can be controlled more easily. MSW uses a nested iteration scheme in which the well-model equations are fully solved at

each reservoir iteration. This allows the effects of discrete events such as changes in a controlling target rate or the opening of new connections to be resolved locally without forcing additional, computationally expensive iterations across the entire reservoir system. Using MSW to model hydraulic fractures in a full-field model means that local changes in fracture flows can also be modeled in a similarly efficient manner.

Fracture Discretization. The hydraulic fractures here are assumed to be planar and square (although this assumption is not a limitation of this approach; the method readily generalizes to any shape of fracture). To compute the fluid flow within the fracture and into the well, the fracture domain is discretized into facets that are arranged in a 2D regular structure. This structure may be modeled by an MSW if each facet is represented by a node, and flows between facets are represented by pipes that connect the well nodes; this is shown in **Fig. 1**. The fracture is thus effectively modeled by lateral looped branches, with the nodes in these branches connected to the nonfractured reservoir.

Fracture Inflow. The flow between the reservoir grid and the well nodes that represent the fracture uses a linear-inflow model in which the connection factor depends on the reservoir grid cell's permeability as well as on the inflow area. This inflow area is computed from the intersection of a fracture facet and a grid cell. The fracture-to-grid connection is generic in that many grid cells can be connected to a single fracture facet and vice versa.

Numerical Experiments

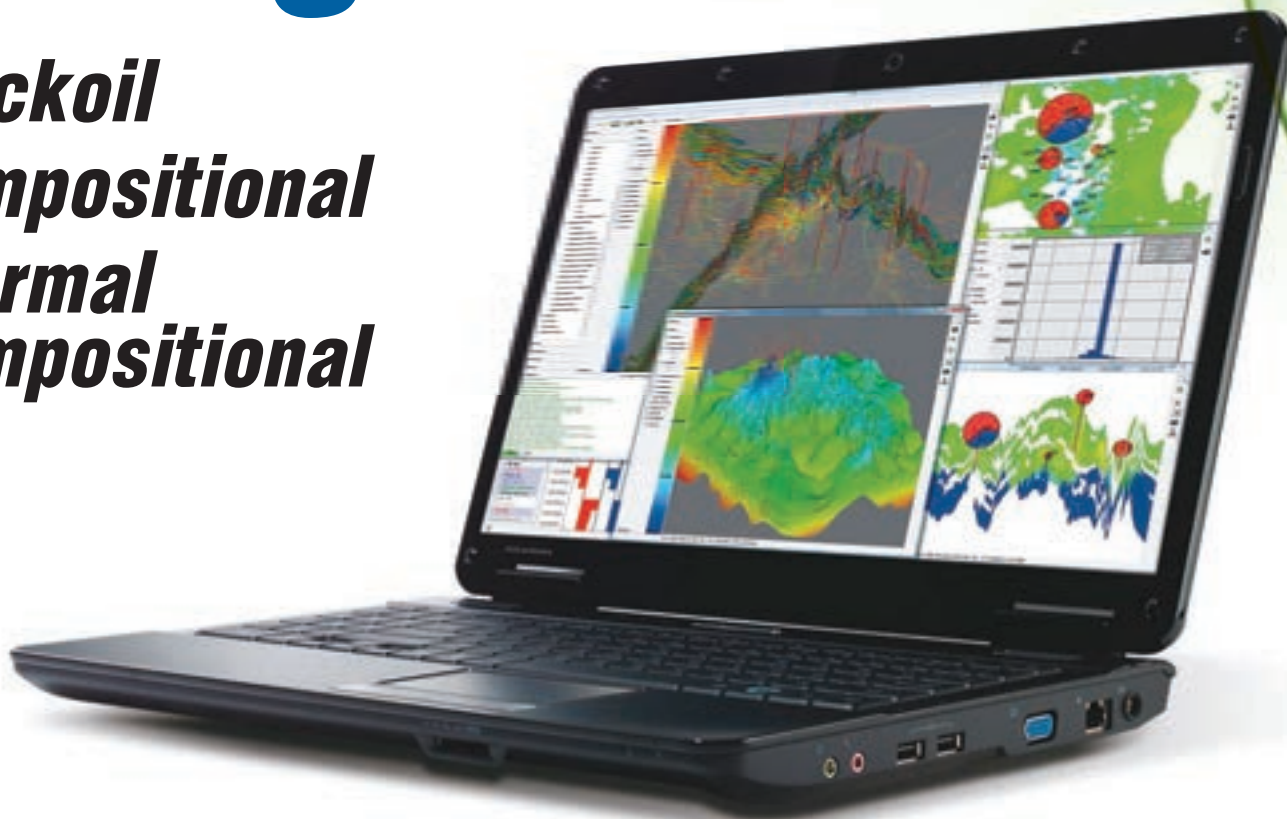
The hydraulic-fracture-modeling approach has been evaluated with regard to suitability and utility. Suitability re-

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 163644, "Representing Hydraulic Fractures by Use of a Multilateral, Multisegment Well in Simulation Models," by D.A. Edwards, SPE, Schlumberger; N. Cheng, SPE, Statoil; T.P. Dombrowsky (now with Longhorn Technologies) and G. Bowen, SPE, Schlumberger; and H. Nasvik, SPE, Statoil, prepared for the 2013 SPE Reservoir Simulation Symposium, The Woodlands, Texas, USA, 18–20 February. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

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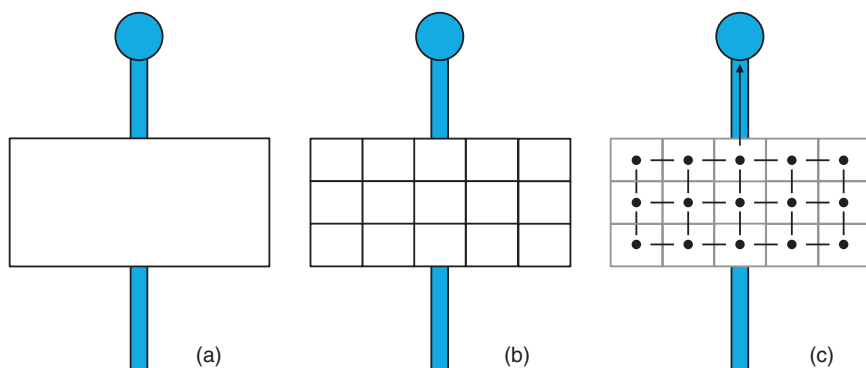


Fig. 1—Fracture as (a) planar object, (b) fracture facets, and (c) fracture segmentation.

lates to the stability and reliability of simulation runs as well as to the accuracy and trustworthiness of simulation results. Utility relates to the performance, scalability, and ease of use of the new approach and shows its applicability to practical real-world modeling scenarios. This approach is evaluated by running a variety of numerical experiments that prove the desired accuracy and usability. These experiments consist of reference-case comparisons and scenario evaluations.

Reference-Case Comparisons

- ▶ Test Case 1: Artificial box-shaped models with a single-phase black-oil fluid model. The purpose of these models is to investigate changes in fracture properties and dimension and the different shapes of wells to which hydraulic fractures are applied.
- ▶ Test Case 2: Artificial tilted models with water/oil contact.

These models have been constructed to show water coning and to investigate the effects of saturation changes (during water breakthrough) on the simulation run.

- ▶ Test Case 3: Models with long horizontal well and multistage fractures. Water injection is used to provide pressure support. Some models have heterogeneous (layered) rock properties to make the model more realistic.
- ▶ Test Case 4: Models with two fractured wells, one producer and one injector. The purpose of these models is to show that fractured injection wells can be modeled with this approach.
- ▶ Test Case 5: Real field sector model. This model showcases the new technology in a realistic model of a deepwater tight reservoir. Multiple production scenarios have been investigated.

In all cases, the model pairs were identical except in how the fracture was modeled, with the reference case using LGRs or tartan grids. This can introduce subtle differences that required the adjustment of model parameters such as well diameter and connection factors. The aim was to keep the differences always to a minimum, for example by using the same number of MSW nodes in the fracture as there are cells in the LGR.

One aspect of the model that caused many problems was the fracture width. Having a realistic fracture width of $\frac{1}{2}$ in. caused numerical instability and problems with the well completions in most LGR cases, so the decision was made to use a pseudowidth of 1 ft for the fractures. This is clearly larger than fractures are in reality, but, by adjusting the fracture permeability accordingly, the correct dynamic behavior was preserved.

Test Case 1: Single-Phase Model.

The simple model presented here was used to investigate the effect of changing the fracture permeability on the oil-production rate. The model is a simple 13×13 grid with a vertical well and fracture. To create the reference case, a 1-ft-wide row of cells has been inserted (in the form of a tartan grid), giving overall dimensions of 15×13 .

Close agreement was seen between the production data for the reference cases and the MSW cases. However, after close inspection, it is apparent that the discrepancies are larger for the poor-quality fracture. Examining the discrepancies in more detail has revealed that the difference in grids between the reference

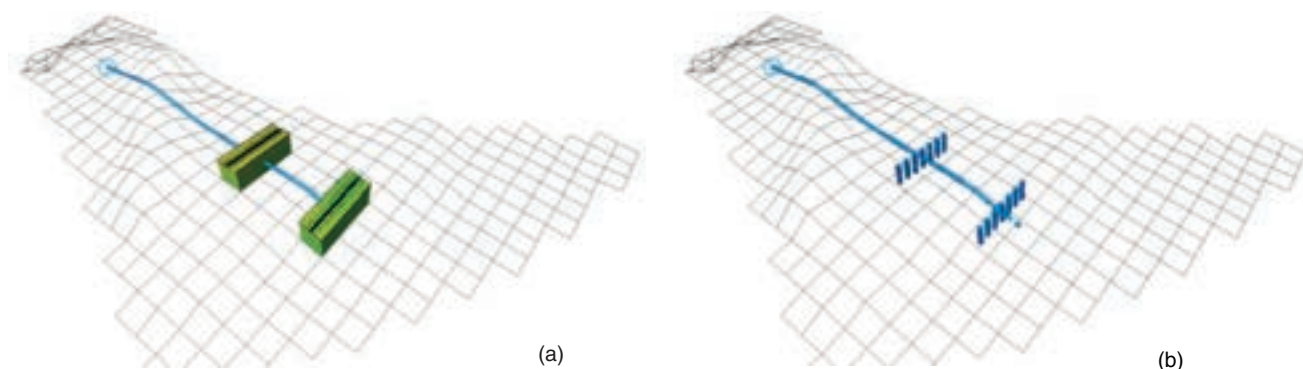


Fig. 2—Real field sector model with horizontal well and two fractures: (a) LGR model and (b) MSW model.

case and the MSW case is the root cause. For high-throughput fractures, the results are virtually identical, and similar findings have been made for many test cases.

Test Case 5: Real Field Sector Model.

The more-complex model setup is shown in Fig. 2. Here, the fracture has been modeled using two logarithmic LGRs.

As expected, the fracturing dramatically increased the plateau time of the production well compared with the non-fractured case. Furthermore, the comparison of oil-production rates and bottomhole pressures with the reference results shows good agreement.

These two cases and the other experiments show generally good agreement between the reference-case results and the MSW fracture results. Furthermore, the MSW fracture simulations were more numerically stable in general than the equivalent reference cases.

Scenario Evaluations

The aim of the scenario evaluations was to provide a broader spectrum of model-

ing scenarios than have been tested with the MSW fracture model. The purpose of these experiments was to determine if the approach is applicable to common modeling scenarios and is useful in real-world engineering studies.

Long Realistic Well. This experiment used a real field sector model with a 3-km-long well. The well was subjected to a multistage hydraulic-fracturing treatment with nine stages. Each stage is represented by a single fracture that extends at odd angles to both grid and well. It would be very hard (if not impossible) to create a reference case for this scenario using traditional modeling techniques.

With the MSW prototype, it is possible to create such a fractured well in minutes; this shows that the new approach opens the possibility of model scenarios that were prohibitively complex in the past, and it has a clear advantage over existing techniques on the grounds of usability. The simulation ran to completion without numerical issues, although,

of course, it was not possible to verify these results.

Multiwell Parallel Scalability. This experiment was concerned with performance. A model with 4 million grid cells and 400 vertical wells, each with a single hydraulic fracture, has been created and run on a cluster. Different degrees of parallelism were used to show the scalability of the new technique with large models. The model has been decomposed into domains by the simulator for parallel execution, with the fluid flows in the grid cells, wells, and fractures in each domain computed on separate processors.

Significant parallel speedups (over serial results) were noted for runs with and without hydraulic fractures, demonstrating the effectiveness of splitting the well solves among processors. This experiment shows that the new technique has been integrated successfully into the existing high-performance infrastructure of a commercial simulator, allowing large-scale scenarios to be investigated in an efficient and scalable manner. **JPT**



			
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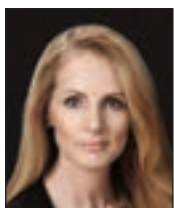
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Recommended additional reading at OnePetro: www.onepetro.org.

IPTC 17361 Geared-Centrifugal-Pump (GCP) Technology Implementation in Petroleum Development Oman as a Potential Alternative Artificial-Lift Method—Oil Wells by A.S. Al-Bimani, *Petroleum Development Oman, et al.*

SPE 165656 Well Optimization Using Fully Instrumented Progressing-Cavity Pumps in the Patos Marinha Field by Kristofer Gustafsson, *Bankers Petroleum, et al.*

SPE 165011 Progressing-Cavity Pumps in Light Oil: Expanding the Application Envelope Through Best Practices and Lessons Learned by Sheldon Jahn, *Kudu Industries, et al.*

ARTIFICIAL LIFT

The digital repository of our valuable SPE papers was first launched as the SPE eLibrary in 1997 and subsequently was updated as OnePetro in 2007. This great collection has become a valuable resource for our global industry. However, several years ago, I noticed that many of the great case studies and technological advancements related to artificial lift were being presented at industry events but not published and captured within OnePetro. I made it a personal mission to change that.

Within SPE today, there are more opportunities for authors to present and publish their work related to artificial lift. For example,

- ▶ The Progressing Cavity Pump (PCP) Workshop was converted to a conference format, which now offers a call for papers.
- ▶ The SPE Digital Edition series “Getting Up to Speed” for both electrical-submersible-pump and PCP technology provided an invitation to authors who previously gave presentations only at industry events to document their work as an SPE paper in these editions and in OnePetro.
- ▶ The Artificial Lift Conference and Exhibition (ALCE) series in the Middle East, South America, and North America was created to bring together the regional artificial-lift experts and document their work as SPE manuscripts. Note that SPE is still working to coordinate these events so that their schedules do not conflict with one another.
- ▶ The ALCE North America event in 2014 focused on seeking out authors with outstanding presentations at regional events (SPE or not), as well as bodies of work that needed to be documented in OnePetro for the benefit of the global artificial-lift community.

The history of artificial-lift technology and the story of its outstanding contributors and innovators have been missing within the SPE realm; however, this is about to change. At the ALCE North America event to be held 6–8 October in Houston, two special events are taking place. The Artificial Lift Historical Exhibit and the Legends of Artificial Lift Awards will be documented and placed in SPE’s historical archives.

The primary and additional papers selected for this feature, with the exception of one Offshore Technology Conference paper, were presented at international events that did not exist a decade ago. The void of artificial-lift information that existed within OnePetro is beginning to be filled and will disappear if we work collectively to seek out our peers and encourage them to publish their outstanding accomplishments and lessons learned as SPE papers. **JPT**

Integrating True Valve Performance Into Gas Lift Design and Troubleshooting

Production-system-analysis methods have been used and are currently used for gas lift design and troubleshooting. These methods, however, have been found to be inadequate in several cases for achieving optimum design or troubleshooting problems. To make up for the inadequacy, a new approach has been applied that uses the Valve Performance Clearinghouse (VPC) database. The new approach joins well performance from production-system analysis and true valve performance from the VPC database to form an integrated system performance tool.

Introduction

Qatar Petroleum's Dukhan field is onshore Qatar approximately 80 km west of Doha. The number of wells in this field requiring artificial-lift assistance has increased over the past few years, and the trend is likely to continue because of reservoir-pressure decline and rising water cut. The availability of gas coupled with compression and distribution-facility availability has made gas lift a natural choice among various artificial-lift methods. The increasing number of wells using gas lift makes gas lift design and troubleshooting key factors in achieving crude-oil-production targets.

Production-System-Analysis-Based Procedure

Production-system analysis determines a well's inflow and outflow performance

and combines them at a solution node to obtain the well's system performance. The purpose of gas lift is to lighten the flowing production gradient by injecting gas into the production string of a well. Gas injection into the production string improves the well's outflow performance by increasing the gas/liquid ratio (GLR) of the production stream from the formation GLR to an objective GLR (OGLR). There are two phases to gas lift operation: unloading and production.

Unloading. The objective of the unloading phase is to leverage gas-injection pressure by sequentially injecting gas through unloading valves (positioned shallower than the operating valve) until the operating valve is uncovered.

Production. The objective of the production phase is to maintain single-point injection through the operating gas lift valve over a range of gas-injection rates while achieving the target production rate.

Inadequacies. A production-system-analysis-based procedure makes some assumptions that could be incorrect or inaccurate.

One assumption is that gas lift valves snap open and snap closed at their opening and closing casing pressures, respectively. For determining valve port size to pass a required volume of gas, first the valve port is considered

to be fully open and, second, an unobstructed flow path is assumed during the gas passage. These assumptions could be incorrect, depending on the way the valve is constructed and the pressure being applied to the valve bellows. In most cases, a gas lift valve is rarely fully open while passing gas. Moreover, the valve stem, downstream restrictions, and the reverse-flow check usually obstruct the gas flow to some degree.

For determining valve-operating pressure, a static-force-balance equation is used. This equation is good only when the valve is closed and is considerably inaccurate when the valve is open. This is because the throttling effect of the bellows spring force is not considered.

Gas lift valves, therefore, show behavior that is markedly different from the assumptions made in the production-system-analysis-based design procedure. As a result, port sizes and operating pressures determined from such procedures turn out to be inadequate in some cases for achieving proper unloading, optimum production, or successful troubleshooting.

True Valve Performance

True valve performance refers to accurate prediction of gas passage through a gas lift valve at pressure and temperature conditions similar to those encountered during unloading and production phases of a gas lift well. This is possible as a result of correlations developed from actual dynamic tests and by use of a property of gas lift valves called "load rate." Load rate is a measure of a valve stem's resistance to movement and relates to the amount of opening the valve will attain for a given annulus and tubing pressure across the valve. True valve performance is made available in the form of a database and application program through license from

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper IPTC 16656, "Integrating True Valve Performance Into Production-System-Analysis-Based Gas Lift Design and Troubleshooting for Dukhan Field, Qatar," by Sanjay K. Singh, James W. Hall, SPE, Eraky Khalil, Balsam Al-Marri, and Reem Al-Abdulla, Qatar Petroleum, prepared for the 2013 International Petroleum Technology Conference, Beijing, 26–28 March. The paper has not been peer reviewed.

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For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

the VPC. The VPC is a not-for-profit joint industry project sharing expenses to establish gas lift valve performance data and correlations.

The Integrated Approach. The integrated approach extends the concept of the operating point for a well to an operating point for the integrated system of well and gas lift valve. An operating point is defined as the point at which the ability of the inflow mechanism to deliver fluid to a specific place is matched by the ability of the outflow mechanism to remove it. The operating point for a well is based on inflow and outflow performance. Similarly, the operating point for the integrated system is defined on the basis of well and valve performances.

Well Performance. The operating point for a well corresponds to the liquid-flow rate and tubing pressure at which the outflow performance matches inflow performance. This operating point (liquid-flow rate and tubing pressure) can be obtained at the position of an ac-

tive gas lift valve for a given well condition through production-system analysis. Because gas injection through a gas lift valve improves outflow performance of the well by increasing GLR above the point of gas injection, production-system analysis is used to obtain different operating points (or no operating point) at the position of active lift valves with changing gas-injection rates.

Valve Performance. The operating point for a gas lift valve corresponds to the gas-injection rate and tubing pressure at the active gas lift valve for a given valve type and port size and for given annulus-pressure conditions. The VPC database is used to obtain different operating points for the gas lift valve with different gas lift injection rates. The locus of all such points when plotted as gas-injection rate vs. tubing pressure gives a valve-performance curve. The valve-performance curve has subcritical, near-critical, and throttling regions. The subcritical region represents the stage of a valve's operation when insufficient pressure differential across

the valve does not allow it to pass the volume of gas it is capable of passing. In the throttling region, a valve's operation is highly sensitive to small changes in tubing pressure, causing obstructed or interrupted gas passage and unstable operation. A valve operating in the near-critical region enables almost steady gas passage and stable operation. Such valve-performance curves can be generated for different valve parameters such as pressure conditions and port sizes.

Integrated-System Performance. The point at which the well-performance curve matches the valve-performance curve provides the operating point for the integrated system of well and gas lift valve. Sensitivity analysis of the integrated system is then performed against changes in well conditions and valve parameters. Such analyses reveal whether the operating point for a given well condition and valve parameter is stable. They also enable adjusting valve parameters (pressure conditions and port sizes) as required to obtain a stable operating point.

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Design and Troubleshooting

The integrated-system performance is used in the creation of a new design or in troubleshooting an existing design for both production and unloading phases of gas lift operation.

Unloading. Unloading valves are designed such that a lower unloading valve should use gas-injection pressure approximately 20–50 psi less than the upper valve. This recommendation assumes that the gas-injection rate at surface is less than approximately 80% of the combined total of gas-injection rate through the upper and successive lower unloading valves when the lower valve uncovers and valve transfer operation takes place. If this happens, gas-injection pressure in the annulus drops to closing pressure of the upper valve and the upper valve closes. This allows unloading to switch from upper to lower valve after some moments of simultaneous operation, without surface adjustments. However, if the gas-injection rate through the unloading valves is less than the surface injection rate, then the gas-injection pressure will not drop but will continue to increase. This issue can result in multipointing and an erratic unloading process. The integrated-system performance enables examining such issues and adjusting the unloading-valve design (spacing, port size, and operating pressures) to allow smooth unloading operation initially and during restarts.

Production. Operating-valve depth and required gas-injection rate to achieve OGLR and target liquid-production rate are determined clearly from a production-system-analysis-based procedure. Choices of gas lift valve types are usually set by the available inventory. However, valve port size and operating pressures are determined on the basis of integrated-system performance. Port size and operating pressures should be such that the operating point falls within the near-critical region of the integrated-system performance for stable operation and provides adequate gas-injection rate across the expected range of well conditions. The same approach is used for troubleshooting an existing design

of operating valve if its performance is suboptimal.

Adjustment Options. The key objective of designing or troubleshooting gas lift is to ensure that the production and unloading phases of the well are stable and smooth. Sensitivity of integrated-system performance is examined by means of several options to achieve this objective. These options include

- Lowering valve set pressure
- Increasing valve-port size
- Increasing gas-injection pressure (if available)

In addition, the option of using a range of temperatures is also available. This is particularly relevant for unloading-valve design because there remains an uncertainty about the temperature at the valve during the unloading phase. During the initial stage of unloading, when there is overbalance against the formation and only the wellbore fluid is being lifted without any flow from the formation, the temperature at the unloading valve is given by the geothermal gradient. However, when the wellbore fluid is sufficiently unloaded to create underbalance against the formation and if the formation fluid (usually a volume of brine lost into the formation during workover, or formation water in case of restart) flows back, temperature at the valve rises. A range of temperatures, therefore, can be used to examine the unloading-valve performance, depending on the unloading stage.

Conclusions

Design and performance management of gas lift wells are key factors in achieving crude-oil-production targets of Dukhan field. Integrating true valve performance into production-system-analysis-based procedures provides an integrated-system performance for the combined system of well and gas lift valves. Analyzing the integrated-system performance for a range of well conditions and valve parameters enables effective gas lift design and troubleshooting. Application of this approach for Dukhan field has resulted in superior well performance, unlocked incremental oil potential at negligible cost, and extended the producing life of wells. **JPT**

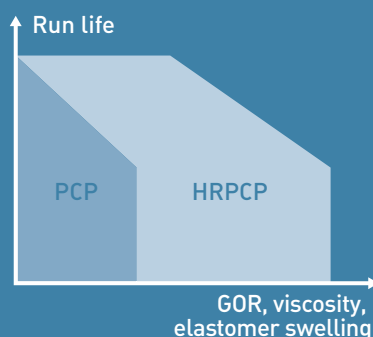
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Applying Root-Cause Failure Analysis Enhances Artificial-Lift Performance

This paper describes the use of a root-cause-failure-analysis (RCFA) process to improve artificial-lift-system performance in a project in Chad. The process was established with the objective of evaluating every failed pump system to determine the reason for failure, identify contributing factors, and monitor trends. The process has helped to reduce the failure frequency by more than 70% on electrical submersible pumps (ESPs) and by more than 50% on progressing-cavity pumps (PCPs), despite the fact that the ESP population has more than tripled and PCP installations have more than doubled.

Introduction

The Chad Project is in the central African country of Chad, approximately 430 km south of N'Djamena, the capital city. The vast majority of the wells are completed with 9½-in. production casing and perforated with 7-in. conveyed perforating guns at 12 shots/ft. The wells are surged to remove perforating debris and are gravel packed for sand control before the artificial-lift system is installed. Typically, ESPs are run with 4½-in. production tubing and PCP systems are conveyed with 5½-in. tubing (Fig. 1).

Formation properties are quite favorable, with permeability ranging from 0.5 to 10 darcies and porosity ranging from 24 to 28%. The hydrocarbon-bearing

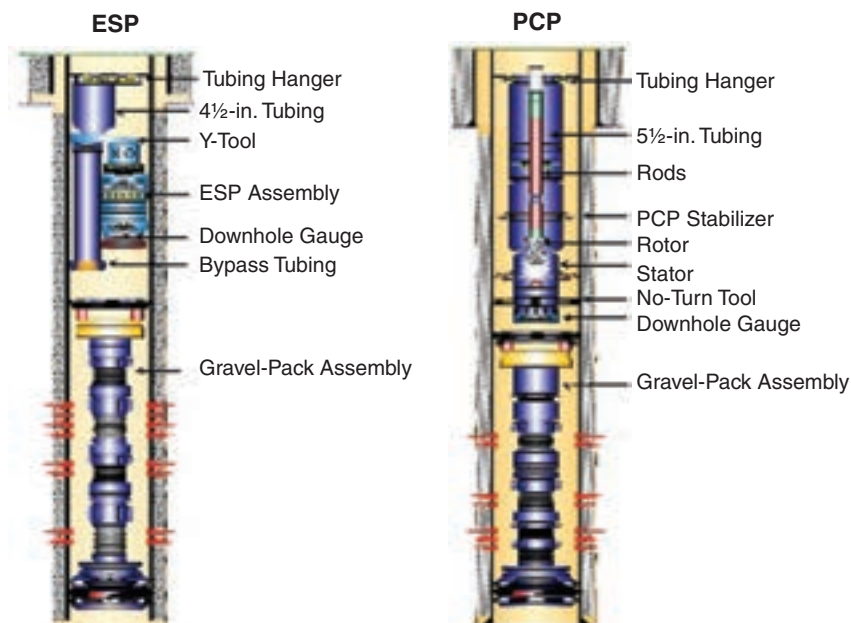


Fig. 1—ESP and PCP completions.

deposits are found at depths as shallow as 3,000 ft and as deep as 6,000 ft. The crude produced from these reservoirs has a gravity of 17 to 24°API, in addition to being heavily biodegraded and undersaturated, with viscosities ranging between 40 and 800 cp. Production is sweet, with no hydrogen sulfide or carbon dioxide, and reservoir temperature is low at 140°F.

High viscosities are encountered when water-in-oil emulsions are formed in the pump when the produced oil and produced water are mixed. At high water

cuts, the mixture becomes an oil-in-water emulsion and ESP performance is not degraded. The inversion point varies because of stabilizing conditions but may be in excess of 80% water cut. The PCPs are not affected directly by the presence of severe emulsions; however, the emulsion typically creates higher flow-line pressures, causing the pump to work harder because of higher backpressure and higher differential pressure across the pump.

Artificial-Lift Operations

Artificial-lift equipment in this project was first used in 2003, with the ESP being the primary type and the PCP being the secondary type. The decision to install an ESP or a PCP depends on the forecast production profile. Typically, if the total fluid production forecast is less than 850 BFPD, a PCP system will be selected; however, an ESP with a Y-tool is preferred when access to the reservoir is recommended for water

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper IPTC 17230, "Artificial-Lift-Performance Enhancements by Applying Root-Cause Failure Analysis," by S.G. Lapi, SPE, and M.E. Johnson, SPE, ExxonMobil Production Company, and B. Arisman, SPE, GE Oil & Gas, prepared for the 2014 International Petroleum Technology Conference, Doha, Qatar, 20–22 January. The paper has not been peer reviewed.

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Fig. 2—ESP test bench.

shutoff, production logging, or special stimulation treatments.

In 2007, the average number of ESP failures per month was nine, with a total average active-ESP-well population of 242 (average failure frequency of 0.45 and peak failure frequency of 0.65). With the help of the RCFA process, the average number of ESP failures per month was six in 2013, with an ESP-well population of 615 (a failure frequency of 0.12). The average number of PCP failures per month in 2007 was six, with a PCP-well population of 155 (a failure frequency of 0.47). The average number of PCP failures per month as of July 2013 has been reduced to 3.7, with a PCP-well population of 210 (a failure frequency of 0.21). High artificial-lift-failure frequencies led to proliferated production downtime and a workover-rig backlog, with the majority of rig activity being pump repair.

A collaborative effort was initiated between the operator and equipment supplier to increase the reliability and performance of the artificial-lift equipment. This alliance resulted in the development of the RCFA process and a fully functional artificial-lift-equipment service center at the Chad field site.

The RCFA process uses the results of dismantle/inspect failure analysis and capabilities of the Field Service Center to increase run life of the ESPs and PCPs.

Challenges

During failure-analysis review meetings, all collected data are reviewed to determine the root cause of failure. If additional data are required, action plans are discussed and responsible parties are assigned to gather and share the necessary data in a follow-up failure-analysis review meeting. Because of the remote location of the operations, delivery of

equipment can take several months; this could have an effect on the performance of the artificial-lift equipment should replacement parts or new equipment be needed. Implementing new technologies and equipment also presents a challenge caused by the amount of time required for shipping; therefore, small trial programs were used to validate concepts.

RCFA Process

The RCFA process used in the Chad Project consists of gathering the data for each artificial-lift-system installation, performing dismantle/inspect failure analysis, and conducting a failure-analysis review meeting with the team. The purpose of the RCFA process is to review the information collected, identify the root cause of failure, share learnings, and provide recommendations to prevent recurrence. Reviews of the data gathered cover the entire artificial-lift process consisting of design parameters, installation reports, operational data, and dismantle findings. The key to a successful RCFA process is reviewing and inspecting all artificial-lift equipment regardless of type or run life.

Gathering Data. The collection and sharing of data have contributed to the foundation of success for the RCFA process. The data reviewed during the RCFA process include reservoir profiles and pump curves used in sizing and selecting the appropriate artificial-lift equipment. Operational data reviewed in the RCFA process include pressure, electrical readings, downhole temperature, well-test data, and parameter settings used in the surface controller.

Dismantle/Inspect Pump Analysis. After equipment is pulled from the well, it is returned to the service center and is subjected to all factory acceptance testing to validate integrity. If a piece of equipment fails testing, the component is dismantled and inspected for failure cause on a dismantle bench.

The dismantle/inspect process is completed by the service company, with a representative from the operator present to witness the findings. Inspection of the failed equipment entails verifying key dimensions and functional requirements of the equipment on the component-specific teardown sheets.

Failure-Analysis Review Meetings. A weekly failure-analysis review meeting to review all open failures is held by means of a teleconference among the operator, equipment supplier, and field operations personnel. The purpose of the review meetings is to guarantee transparency among the parties while ensuring that the root cause of failure is identified. The key to determining the true root cause is to focus on why the equipment failed and not on what equipment failed. It is important to know what component failed because this may help to provide insight concerning the cause; however, it is paramount to derive why the equipment failed and whether it is related to manufacturing, to design, or to operating or well conditions.

Service Center

The Service Center, located in the field operations, is designed to validate all acceptance tests performed after manufacture for ESP components. The ESP motors and seals are tested upon arrival in the country to ensure that no issues have occurred during shipping. All pulled equipment is retested to identify failed components and conduct further analysis. The Service Center is also capable of testing PCP systems.

ESP Capabilities. Testing capabilities for ESP equipment (Fig. 2) include efficiency, vibration, head, and brake horsepower. New ESPs are typically not tested; however, all pumps returned from service are tested before being placed back into inventory or being dismantled. The ESP cable and sensors are tested during final assembly.

During a pull of an ESP string from the field, the motor and downhole sensor remain assembled when shipped to the Service Center. The attached sensor



Fig. 3—PCP test bench.

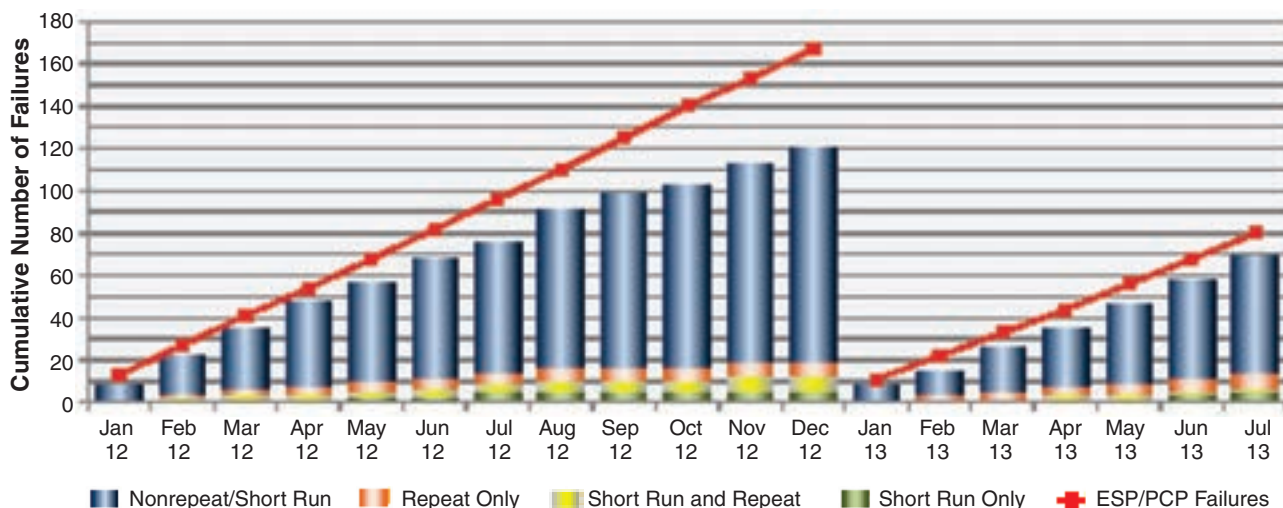


Fig. 4—2012-13 artificial-lift performance.

is tested through the motor by means of the sensor surface unit. This testing verifies that the sensor outputs are measured accurately. All ESP motors are fully tested before being run downhole and are tested again after being pulled. ESP seal sections are also tested to ensure that

thrust loading, horsepower, vibration, and mechanical seals are within factory performance and functional limits.

PCP Capabilities. In the early stages of the project, PCP systems were tested for flow, pressure, torque, and revolutions per minute on a bench, as seen in Fig. 3. PCP systems were tested before being run in hole to validate the factory bench test and to verify that no damage was caused to the unit during shipping. Because of the nature of the PCP failures, most PCP systems do not receive a bench test after being pulled from the well. The independent testing capability for PCP systems enables testing of pumps before and after being pulled, if needed. The key dismantle/inspect checks include verifying model numbers, serial numbers, component lengths, and component condition.

The PCP inspection also includes inspecting torque anchors and providing analysis of the rotor and stator after the unit has been run.

Performance Monitoring

In order to provide clear communication to all parties involved, recurring overview meetings are held among the operator, the service company, and the field operations staff discuss current run-life statistics and to make recommendations for improving or extending the run life; hence, this team has been named the Extended Run Life Team (ERLT). These ERLT meetings consist

of technical and operations staff from all parties, including management from each party, focused on action items identified by the RCFA team. Key performance indicators are discussed in these meetings to confirm that the metrics established are being managed to optimize pumping performance. Constant monitoring of the failure data and frequent failure-analysis review meetings have improved performance of the artificial-lift systems, as shown in Fig. 4. By reviewing the current failures, the ERLT has also been able to make application improvements with the ESP seal sections and motor.

The primary focus of the ERLT is correcting issues with short runs (consisting of failures less than 90 days) and with repeat failures within 365 days, as seen in Fig. 4. This figure shows that the RCFA process has helped to focus on short-run and repeat failures; it also shows that actual failures are below forecast. For instance, in October 2012 there were only three failures with approximately 800 active wells.

A study of these failures helps to identify opportunities to improve operations and procedures that are causing the failures. Once the opportunities are identified, a development plan is put together and implemented to improve pump performance and extend equipment run life. Further data analysis is conducted on the long-run wells to explore ways to extend run life of ESP and PCP equipment. **JPT**

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High-Power ESP Tubing-Hanger Connector for Deepwater Downhole Applications

Reliability of subsea equipment is an indispensable requirement in deepwater applications. Tubing-hanger (TH)-connector systems can be a critical failure mode for electrical submersible pumps (ESPs) in high-pressure/high-temperature (HP/HT) environments. Through use of reliability tools such as fault-tree analysis (FTA), failure-mode effect and criticality analysis (FMECA), and systems reliability block diagrams (RBD), it was established that improving the reliability of the TH-connector system has a direct effect on the unattended life of the ESP electrical system.

Project Basis of Design

A joint development project between the operator and the connector-system supplier focused on the design, installation, and intervention of downhole ESPs in deepwater subsea wells in the Lower Wilcox developments in the Gulf of Mexico. The system design encompasses the ESP completion, subsea wellhead, tree, TH, and power and control system. The system design criteria are for 8,000-ft water depth and a 14-mile tieback (Fig. 1).

Connector-System Reliability Overview

At the start of the project, the operator, the connector-system supplier, and other equipment vendors met and agreed to align their reliability plans. Common reli-

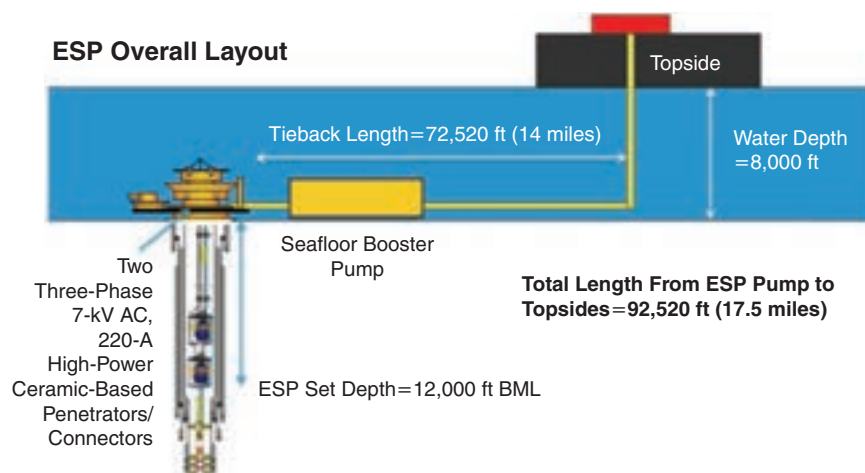


Fig. 1—The ESP overall layout. BML=below mudline.

ability tools, including FTA, FMECA, and systems RBD, help all collaborators to have a better understanding of the relationship and sensitivity between subsystem reliability and the unattended life of the ESP electrical system.

FMECA. The FMECA process is typically performed by the present multiple teams to capture different backgrounds and benefits for a wider range of feedback. In this process, each component and subsystem is considered and its corresponding functions are identified. The purpose is to consider the conceivable failure modes associated with each component and function on the basis of prior art, knowledge, and industry experience and then develop plans to mitigate such failure modes in a hierarchy that is based on the criticality.

To establish the criticality associated with each failure mode, the severity, probability of the failure (P), and current controls used to detect failures before occurrence (D) are determined and ranked. The rankings are set on a scale of 1 to 10 points for the severity (S), with 1 being no effect and 10 being catastrophic failure; for occurrence (O), with 1 being very unlikely to occur and 10 being extremely likely; and for detectability (D), with 1 being immediate detection and 10 being almost impossible to detect for each failure mode. These three numbers are multiplied to determine the risk priority number (RPN) of each failure mode: $RPN=S \times O \times D$.

The RPN is used to determine a risk classification of high, medium, or low for each failure mode on the basis of ranges set at the beginning of the FMECA exercise. All high-risk items are required to have a mitigating action in place, and that is typically followed by addressing all medium-risk items also. The ultimate goal is to bring every failure mode to a low-risk level and to have mitigated or considered all low-risk items at some point during the development process.

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper OTC 24138, "Reliable High-Power ESP Tubing-Hanger Connector Systems for Deepwater Downhole Applications," by Sami Spahi, Teledyne Oil and Gas, and Pamela Parsley, Chevron Energy Technology Company, prepared for the 2013 Offshore Technology Conference, Houston, 6–9 May. The paper has not been peer reviewed.

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Accelerate Life Testing (ALT). The concept of ALT is testing under stress levels in excess of those of expected operating conditions. The experimental data results are used to project performance under actual-use conditions. Several stressing methods can be used. The choice of stressors typically depends on expected exposures during operation. Stressors may include temperature, voltage application, load, or chemical exposure. Test setups are designed on the basis of failure modes of interest such as contamination, electromigration, corrosion, and creep.

The three main components of ALT are test planning, acceleration models, and parameter estimation. Test planning includes the physics-of-failure study to understand the failure mechanism and the input variables. Other aspects of test planning include the number of test units, test time, and test setup. An acceleration model describes the relationship between the acceleration variable (e.g., temperature) and the life of the units under test.

FTA. A fault-tree model, a tool commonly used to establish the reliability on the basis of statistical knowledge of various failure modes and their frequency of occurrence, is implemented during the system-reliability analysis. The systems fault tree encompasses all vendor subsystems that are broken down to the subassembly and component level. This helps the teams identify the effect of each component on the reliability of the integral system and the degree of sensitivity.

HP/HT-Connector-System Overview

High-Power-Connector-System Concept-Design Overview. The design of an ESP high-power (medium-voltage) connection system comprises a wet-mate penetrator connector pair, TH feedthrough, and dry-mate splice/ESP-cable termination (**Fig. 2**). The design is based on existing high-power connector technology, with each phase of the electrical system isolated and electrical stress relieved adequately for long-term reliability. The design uses various

insulation materials including ceramic, polyether ether ketone, and multilayer elastomeric seals to achieve phase isolation in addition to mechanical sealing. The penetrator is composed of a ceramic-insulation-based wet-mate plug pin, which is intended as a secondary pressure barrier from annulus to environment. The wet-mate connection is achieved by means of an oil-filled and pressure-balanced receptacle module.

The dry-mate splice is divided into two canisters, or a two-stage assembly: The upper canister (first stage) is assembled and oil filled in house after mounting the wet-mate plug pin and feedthrough onto the TH. The lower canister (second stage) is installed and oil filled in field, terminating to the predeployed ESP cable.

The upper and lower dry-mate splice canisters are oil filled with dielectric fluid and designed to be pressure balanced to annulus pressure at all times.

HP/HT Wet-Mate Ceramic Penetrator. The TH HP/HT penetrator assembly

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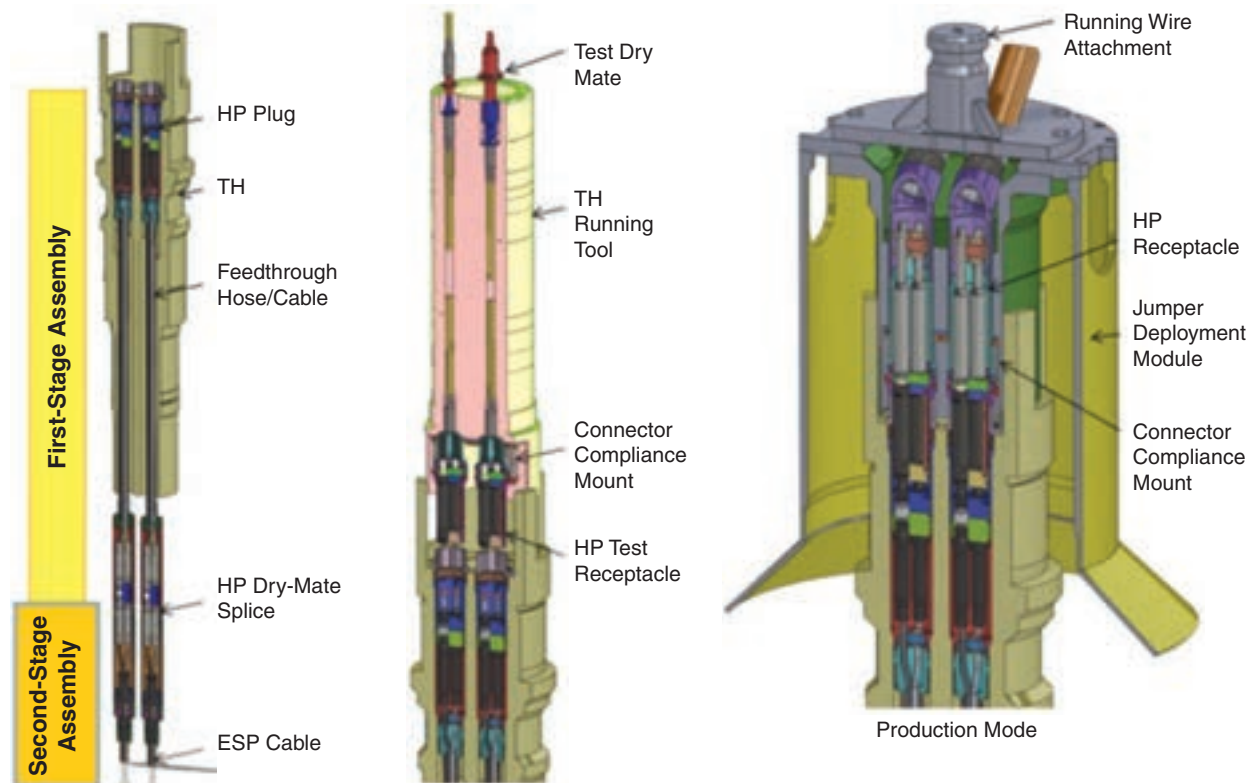


Fig. 2—ESP high-power-connection-system overview.

consists of a three-way high-power wet-mate ceramic-based plug pin (Fig. 3). The design is based on the use of metalized-ceramic insulation that is electron beam welded to a copper pin. The ceramic insulation has been selected on the basis of its ability to support high pressures at high temperature with minimal creep or degradation over time.

Dry-Mate Splice for ESP-Cable Termination. The dry-mate splice is in the annulus and is divided into two isolated compartments (Figs. 2 and 4). The first compartment (upper canister) is part of the first-stage TH assembly and oil-filling process. The second compartment (lower canister) is part of the second stage, is installed and oil filled in field, and terminates at the ESP. Both compartments are pressure balanced to annulus pressure by use of metallic bellows accumulators. Throughout the connector system, the shielded conductor boot seals are considered the primary insulation and are designed to operate reliably in a totally flooded (annulus-fluid-ingress) condition. The dielectric fluid surrounding the conductor boot seals is considered secondary

electrical insulation. The material selection is based on a long-term material-compatibility program that was tested specifically in the annulus environment.

ESP High-Power Receptacle Module. The three-way receptacle subassembly consists of three individual-phase isolated receptacle stem modules. The receptacle stem module houses the socket contact stem, which consists of gold-plated contact seats and silver-plated contact bands mounted within a carrier on the end of a conductive tube that houses a spring-biased retracting insulating stopper. The stopper seals a dielectric-oil-filled, pressure-balanced chamber that surrounds the socket contact. Each contact has its own oil-filled chamber, and, in turn, they are housed inside a common secondary oil-filled chamber, thus giving two independent barriers between the circuit and the environment.

During the mating action of the two halves of the wet-mate connector, the plug/pin contact enters the socket chamber by displacing the stopper, and, at the same time, its surface is wiped clean of any seawater, surrounding fluid, or con-

tamination by a series of wiping seals at the front of the chamber. The electrical connection is established within the benign-fluid environment. During disconnection, the plug retracts from the receptacle chamber and the spring-biased insulating stopper returns and fills the vacated space and seals off the chamber to prevent any oil leakage or external-fluid ingress.

Prototype Testing

Because the technology is relatively new, comprehensive prototype-validation testing was necessary for benchtop-configured components and subassemblies in a relevant environment. More than 50 prototype tests were performed to mitigate all high technical risks and most medium risks before starting the qualification program.

The extensive prototype-validation-program tests provided the flexibility to perform adjustments for design optimization and provided more confidence (reduced risk) during the qualification program and system-integration tests at the field. Please see the complete paper for examples of the prototype-validation tests that were performed.

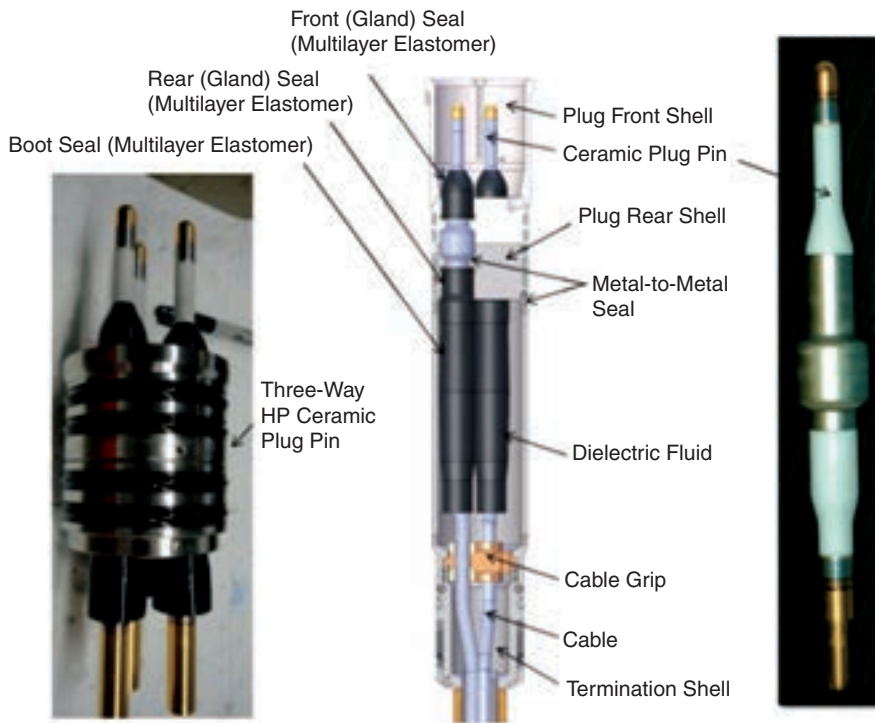


Fig. 3—TH HP/HT wet-mate ceramic penetrator.

Qualification Program

The qualification program was conducted over 18 months. During the first 4–5 months, the qualification test procedures were prepared and approved. In the meantime, three preproduction connector sets were built through a complete production cycle. During the next 12–16 months, the short-term tests and the long-term tests were performed simultaneously.

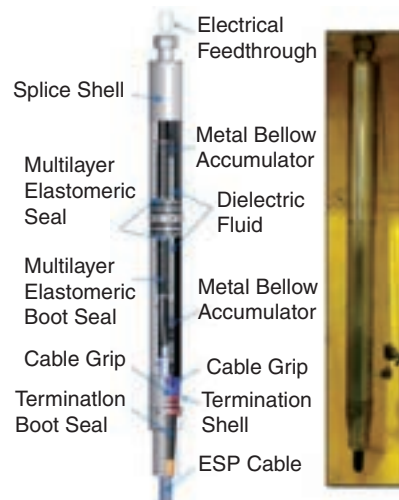


Fig. 4—Dry-mate splice for ESP-cable termination.

System-Integration Tests

The project planned for a system-integration test of the complete high-power connector system and subsea-equipment-supplier components. The scope of the test is to use full-scale production parts of each component. The testing goals were

- ▶ Use full-scale production parts.
- ▶ Measure continuity of the connection of the high-power wet-mate system.
- ▶ Validate assembly procedures.
- ▶ Verify debris tolerance of high-power connector system.

Conclusion

Throughout the duration of the joint development technology project between the operator and the connector-system supplier, the focus has been on reliability of the high-power connector system. The key factors for a well-established reliability system for this connection-system project are the following:

- ▶ Reliability consideration from the beginning of the project (concept design), by use of the FMECA process and other tools
- ▶ Comprehensive materials-compatibility and -aging program

- ▶ Extensive prototyping effort and component-validation test, with more than 50 prototype tests performed to mitigate all high risks and most medium risks before starting the qualification program
- ▶ Integration fit testing using operator equipment or prototype equipment
- ▶ Full qualification testing (short term and long term) that encompasses different industry standards along with nontraditional qualification tests that are based on the application
- ▶ Early system-integration tests and system deployment to obtain field experience
- ▶ Coordinating high-power-connection-system reliability with other reliability systems and teams by use of reliability tools such as fault-tree diagrams. **JPT**




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Recommended additional reading at OnePetro: www.onepetro.org.

SPE 165705 Impact of Delays and Shut-Ins on Well Productivity

by James W. Crafton, *Performance Sciences, et al.*

SPE 166176 Production Analysis in the Barnett Shale—Field Example for Reservoir Characterization Using Public Data

by H. Pratikno, *ConocoPhillips, et al.*

SPE 164534 Time-Dependent Fracture Interference Effects in Pad Wells

by Ripudaman Manchanda, *The University of Texas at Austin, et al.*

UNCONVENTIONAL RESOURCES

Flowback (or cleanup) of fracturing treatments can have a profound influence on well productivity in unconventional reservoirs. The process of cleanup crosses many discipline boundaries. Given this complexity, it can be unclear who is ultimately accountable. Ensuring that someone is ultimately accountable is vital to maximizing the well results.

The most ideal form of flowback is one that maximizes production while meeting or exceeding environmental requirements.

The ideal flowback is reservoir dependent. In some reservoirs, immediate cleanup is preferential. This approach takes advantage of pressure gradients created during pumping to maximize fluid recovery (e.g., the “slowback” approach). In other reservoirs, extended shut-ins after fracture treatment can support improved productivity. In these cases, positive injection-fluid/rock interactions are encouraged and the pumped fluid may act as a form of propping agent. The challenge is in understanding what the best approach is for your environment.

Many disciplines have an effect on fracture-treatment cleanup. Reservoir and production engineers must understand the efficacy of the process by analyzing existing information such as well pressures, rates, and return-fluid composition. Completion and drilling engineers must ensure that the well trajectory and the well completion support the process of unloading fracturing fluids. Stimulation engineers must design fracturing treatments to promote cleanup. Operations engineers must manage flowback in the field to design specifications, reporting accurately and ensuring that environmental standards are met.

The ideal flowback is a virtuous cycle. The capture of fluids minimizes environmental effects. Capturing these fluids also allows them to be analyzed for fluid composition, rates, and flowback pressures, which can be used to optimize the cleanup process. The result is a cleaner environment and better-producing wells.

Achieving the perfect flowback requires multiple disciplines working in close cooperation. However, it is critical to use the talents of an individual who is capable of overseeing all facets of the process and who is ultimately accountable. Who is ultimately accountable for the fracture-treatment flowback process in your organization? **JPT**

Fracture Stimulation in the First Joint-Appraisal Shale-Gas Project in China

This paper discusses fracture stimulation in the first joint-venture shale-gas project with foreign companies in China. The block is in Sichuan province, and the target zone is Longmaxi hot shale, a Silurian formation. Its matrix permeability is extremely low (100 to 300 nanodarcies), but it is rich in natural fractures. Hydraulic fracturing has been shown to be critical to enhancing production. A collaborative approach was applied to the completion of the shale gas wells during appraisal.

Introduction

Most of China's proved shale-gas resources are in the Sichuan, Tarim, and Ordos basins. China's technically recoverable shale-gas resources are estimated at 1,275 Tcf. The operator jointly appraised a shale-gas block in Sichuan with PetroChina. The project team needed to make several determinations in the early phase of the project, such as whether there is sufficient gas in the shale formation and whether the gas can be extracted at a high-enough (commercial) rate. From the production technologists' perspective, the technical objectives of the early wells included the following:

- Test the ability of the Longmaxi hot-shale interval to be fractured under high formation pressure.

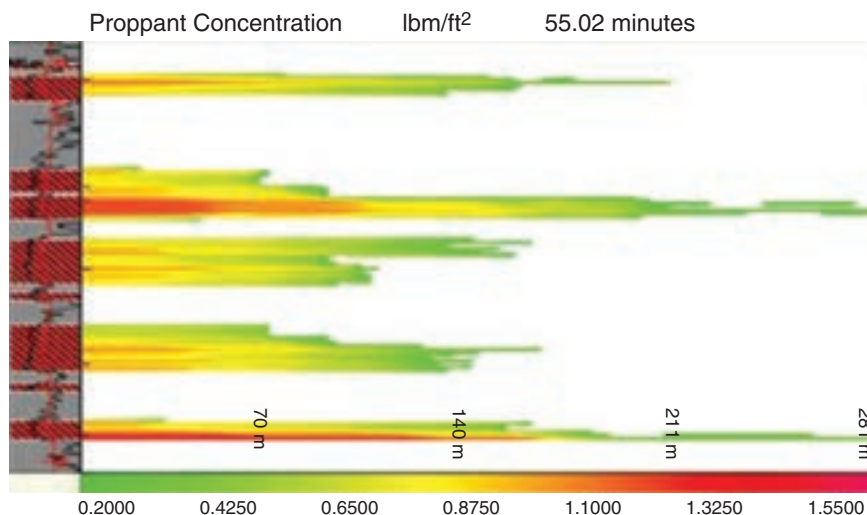


Fig. 1—Fracture design for a vertical well.

- Establish baseline fracture designs for the Longmaxi hot-shale interval, at greater than 3500-m true vertical depth (TVD), and systematically evaluate the design parameters.
- Establish an effective multidisciplinary workflow.
- Gather fracture-stimulation-performance data and subsurface-pressure information.
- Determine the productivity of the gas from the appraisal wells to prove the presence of a shale-gas play.

The joint-appraisal phase began in November 2010. While planning the drilling of deep wells to evaluate the Longmaxi formation, data were obtained from several shallow wells at a location close to the surface. Extensive laboratory tests were conducted to evaluate the geochemical properties of the rock. In addition, some rock-mechanics properties were measured. The drilling of the first well (Well A) began in December 2010, and hydraulic fracturing began once the well reached designed depth. To date, five wells have been drilled; two are vertical, and three are horizontal.

A team was established to design and execute the hydraulic-fracture stimulations and production testing of the stimulated wells to reveal the shale-gas-production potential. The team has worked with various disciplines to establish an integrated workflow incorporating shale-gas best practices, especially those from North America. However, one of the key aspects of shale-gas development is that every shale reservoir is different. This means that unique so-

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper IPTC 16762, "Successful Fracture Stimulation in the First Joint-Appraisal Shale-Gas Project in China," by Liang Jin, Changlong Zhu, Yong Ouyang, Ming Zhou, Qingguang Qu, Fei Li, Roger Yuan, Chris Wu, Zhiyi Zhang, Yan Wang, and Fa Dwan, Shell China Exploration & Production; Sanjay Vitthal, Shell Canada; and Shiqian Wang, PetroChina Southwest, prepared for the 2013 International Petroleum Technology Conference, Beijing, 26–28 March. The paper has not been peer reviewed.

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For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

lutions must be crafted on the basis of the specific challenges of the reservoir, such as

- ▀ High wellhead treating pressure caused by high formation stress and pore pressure.
- ▀ Deep wells (deeper than 3500-m TVD on average).
- ▀ The service industry in Sichuan is different from that in other areas of the world in that local service companies provide most stimulation services. The project team had to work with both local and international companies to set up the service infrastructure.
- ▀ Fracture geometry (diagnostic technology had to be applied to detect the geometry of the created fracture in order to evaluate the effectiveness of the stimulation).

Hydraulic-Fracture-Stimulation Conceptual Procedures

The project team engaged with internal expertise involved in North American shale-gas operations and industry experts to plan the stimulation strategy. On the basis of the existing information from the shallow cores and the general understanding of the geological and geo-mechanical setting of the play, conceptual stimulation design and procedures were agreed upon for planning purposes.

Vertical Wells. Vertical wells served important exploratory purposes. A full suite of data-gathering techniques for subsurface evaluation needed to be conducted. Once target zones were identified, the wells were hydraulically fractured to test whether hydraulic-fracture stimulation would enhance production and provide information for further evaluation of well productivity in horizontal wells. The main objective in fracturing the vertical wells was to test the ability of the rock to be fractured to develop the operational windows for further horizontal-well-stimulation design and execution (Fig. 1). With limited information available at the time of planning hydraulic fracturing while the vertical wells were being drilled, a conceptual design was put in place by integrating best practices from existing assets and experience obtained by the industry at large.

Fracturing Design Concept.

- ▀ Low-viscosity water [usually called slickwater (SW)] is the main fracturing fluid, with a low concentration of proppant (1 to 2 lbm/gal).
- ▀ Pumping procedure: High pump rate (40 to 60 bbl/min) at the highest possible treatment pressure.
- ▀ Perforation strategy: limited-entry design flexibility.
- ▀ Large proppant volume per unit thickness (1.5 to 2 t/m).
- ▀ Liquid volume: 1000 to 1500 m³.

Target.

- ▀ If the fracture geometry is of the network type, try to activate the natural-fracture network.
- ▀ If the fracture is planar, try to create large fracture half-length (150 to 450 m).
- ▀ Maintain post-closure conductivity: no proppant flowback.

Fracturing Operational Procedure.

- ▀ Plug, perforate, fracture.
- ▀ SW plus low-concentration gel.
- ▀ 100-mesh sand and 40/70 ceramic proppant.
- ▀ Mill plugs and initiate flowback.

Horizontal Wells. Once a target zone is identified through a successful stimulation of vertical wells, a horizontal well is drilled along the target zone. Then, multiple stages of hydraulic fractures are placed in the horizontal section to evaluate the productivity and economical viability of the shale-gas play. Depending on the understanding of regional and local stress conditions, the well trajectory needs to be planned so that the fractures will grow in a favorable pattern.

Fracture-Design Concept and Fracturing Procedure.

- ▀ Design stage spacing on the basis of core and log data.
- ▀ Coiled-tubing sand jetting for the first stage, plug/perforate/fracture for the remaining stages.
- ▀ High pump rate (greater than 70 bbl/min).

- ▀ Hybrid fluid (SW plus low-concentration gel).
- ▀ Limited-entry perforation design.
- ▀ Proppant quantity of 80 to 120 t per stage.
- ▀ Liquid volume: 1000 to 1500 m³ per stage.

Hydraulic-Fracture Designs: Methods and Parameters

As the wells are drilled, cores and logs are acquired; real hydraulic-fracture designs are then conducted by the integrated team. A series of studies are performed to obtain key information related to the identification of target zones and to define key parameters. Methods used in defining some of the parameters of the fracture stimulation design are described in the following:

- ▀ Target-zone selection: Log and core-test results. Longmaxi rock properties are most favorable at the base of the hot-shale package.
- ▀ Rock mechanics: derived from log data. The log is calibrated with laboratory-test results, such as brittleness and completion-efficiency studies.
- ▀ Stress: log-derived, calibrated with core-test-derived correlations and diagnostic-fracture-injection-test (DFIT) data.
- ▀ Reservoir pressure: pore-pressure prediction and DFIT data.
- ▀ Fluid selection: SW, linear gel, crosslinked gel (database and laboratory tests). Fluid type is dependent upon the rock properties and related to brittleness and hardness. Fluid type varies from hybrid to linear gel to SW to create dendritic fractures. From the rock and geomechanics tests thus far, the Longmaxi shale is more likely to be brittle rock. Therefore, the fluid system is mostly SW with limited linear gel to carry higher concentrations of proppant.
- ▀ Proppant: Closure-stress prediction, instantaneous shut-in pressure, and local stress study (DFIT verification). On the basis

of the stress conditions, higher-strength ceramic proppant was selected to ensure that fracture conductivity would not restrict the gas flow.

- **Fracture-treatment design:** Various hydraulic-fracture-design software packages have been used as design tools and for comparison in gaining better understanding of formation and engineering parameters.
- **Calibration of fracture-design models:** Tracer technology, production logging, and microseismic measures are some methods used to provide fracture-geometry information for data analysis. This is combined with other information such as DFIT data to improve fracture designs.

Horizontal-Well Stimulation. Vertical Wells A and B produced gas to the surface, demonstrating the presence of a shale-gas play. To evaluate the reservoir potential, the team also had to establish potential for commercial flows through horizontal wells. This was performed by the following means:

- Long-term production (greater than 6 months) is typically required for decline analysis to estimate well estimated ultimate recovery (EUR).
- Horizontal wells would increase the probability of encountering natural-fracture systems.
- North American shale-gas development is based on horizontal-well development, where drilling and completions are optimized with successive wells.
- However, the horizontal-section length is typically limited in early wells and increases with experience in the play and overcoming technical challenges. The resulting EUR of the well is sensitive to horizontal length.

For the succeeding wells, the concept has been changed to drilling a pilot

vertical well to define the target zones and then sidetrack to drilling a horizontal section covering the targeted zones.

Optimized Perforations (Horizontal Wells). Hydraulic-fracturing design is an iterative process. Once the well is drilled and log information is obtained, the team will go through a process to select the target zones and determine the stages to realize the production-testing objectives. For each selected horizontal section, the number of needed perforation clusters will be determined, along with how to place them in the selected sections to maximize stimulation effectiveness. A perforation-optimization process is part of the iteration process.

Cooperation. Integration and cooperation within the project team and among the parties involved in all phases of the operation are key to the success of the shale-gas project. The project team had engaged all service partners throughout the process to ensure safety, quality, and efficiency. In the meantime, all parties were encouraged to make suggestions for improvement. The influence of North American expertise was also an important part of the team's cooperative success. In order to optimize data access for people not on the well-site to provide real-time support, data transmittal through a Wi-Fi network was established.

Key Lessons and Future Work

- The Longmaxi formation has the potential of producing gas with proper well configuration and stimulation.
- The focus will be on increasing EUR per well, reducing costs and land use, and managing water.
- Simulation work is in progress that will combine rock-mechanics-test results to generate correlations to calculate rock properties.
- Stimulation-quality study results will be compared to have a better understanding of reservoir properties. **JPT**

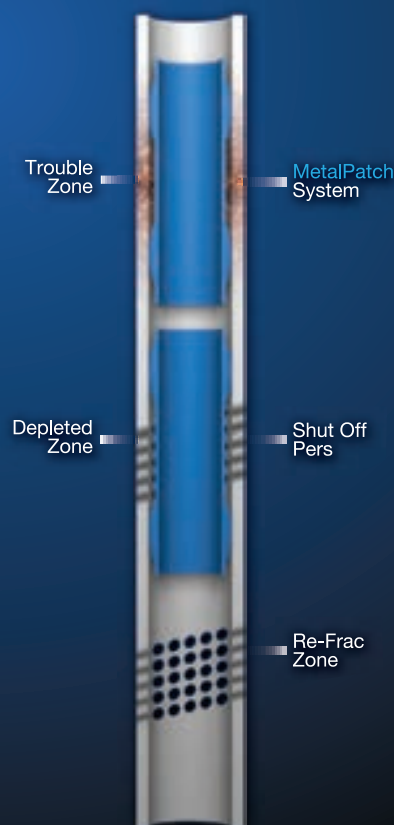
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Unconventional-Reservoir Development in Mexico

In 2010, exploration of gas-rich and possibly liquid-rich shale reservoirs began in northern Mexico. A two-stage integrated workflow was developed to achieve set objectives. The drilling stage used a petrophysical and geomechanical static model to identify the most prospective interval in the reservoir, define the best drilling azimuth and landing point, and reduce drilling risk. Real-time geosteering was implemented to achieve the targeted navigation window. In the completion stage, reservoir-centric completion-and-stimulation software was used to optimize completion and stimulation design.

Introduction

The initial target formation was the Upper Cretaceous Eagle Ford; the second was a Jurassic formation locally called Pimienta.

The Eagle Ford shale is a Late Cretaceous hydrocarbon-producing formation composed of organic-rich calcareous mudstones with mineralogical composition with ranges of 5–20% quartz, 15–25% clay, and 65–80% carbonate, and with a total-organic-carbon (TOC) range of 1–6%. The Eagle Ford shale is overlain by the Austin chalk and overlies the Buda limestone. It has been divided into two units, a lower unit deposited during transgressive sequences and an upper unit deposited in a regres-

sive sequence. Both units were deposited in a low-angle sloping ramp. As of July 2012, five wells had been drilled in the Eagle Ford formation: A_{EF}, B_{EF}, C_{EF}, D_{EF}, and E_{EF}.

The origins of the Pimienta formation date to the Late Jurassic. It is an organic-rich source rock with potential for hydrocarbon production as an unconventional reservoir. Its mineralogical composition exhibits ranges of 20–40% quartz, 25–45% clay, and 20–40% carbonate, with an average TOC range of 3–4%. As of July 2012, one well (A_P) had been drilled in the Pimienta formation.

Methodology: Implementation of a Multidisciplinary Workflow

The implementation of the workflow was divided into four phases, as follows:

- ▶ Phase I: predrill modeling
- ▶ Phase II: geosteering and real-time monitoring
- ▶ Phase III: completion design, hydraulic-fracture modeling, and execution
- ▶ Phase IV: evaluation of well performance

Phase I. A 1D mechanical Earth model (MEM) applied to hydraulic fracturing was used to integrate all available data and to describe more accurately the in-situ stress, the workflow for the geomechanical model, and the integration of the information. For a detailed description of the work performed in this phase, please see the complete paper.

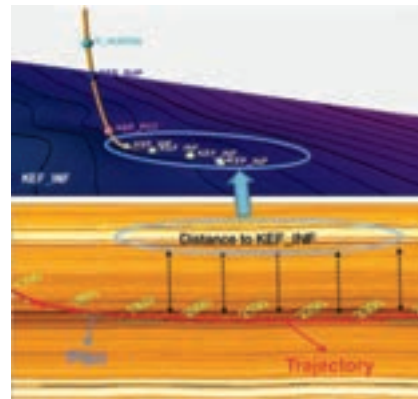


Fig. 1—Structural model updated with information from LWD.

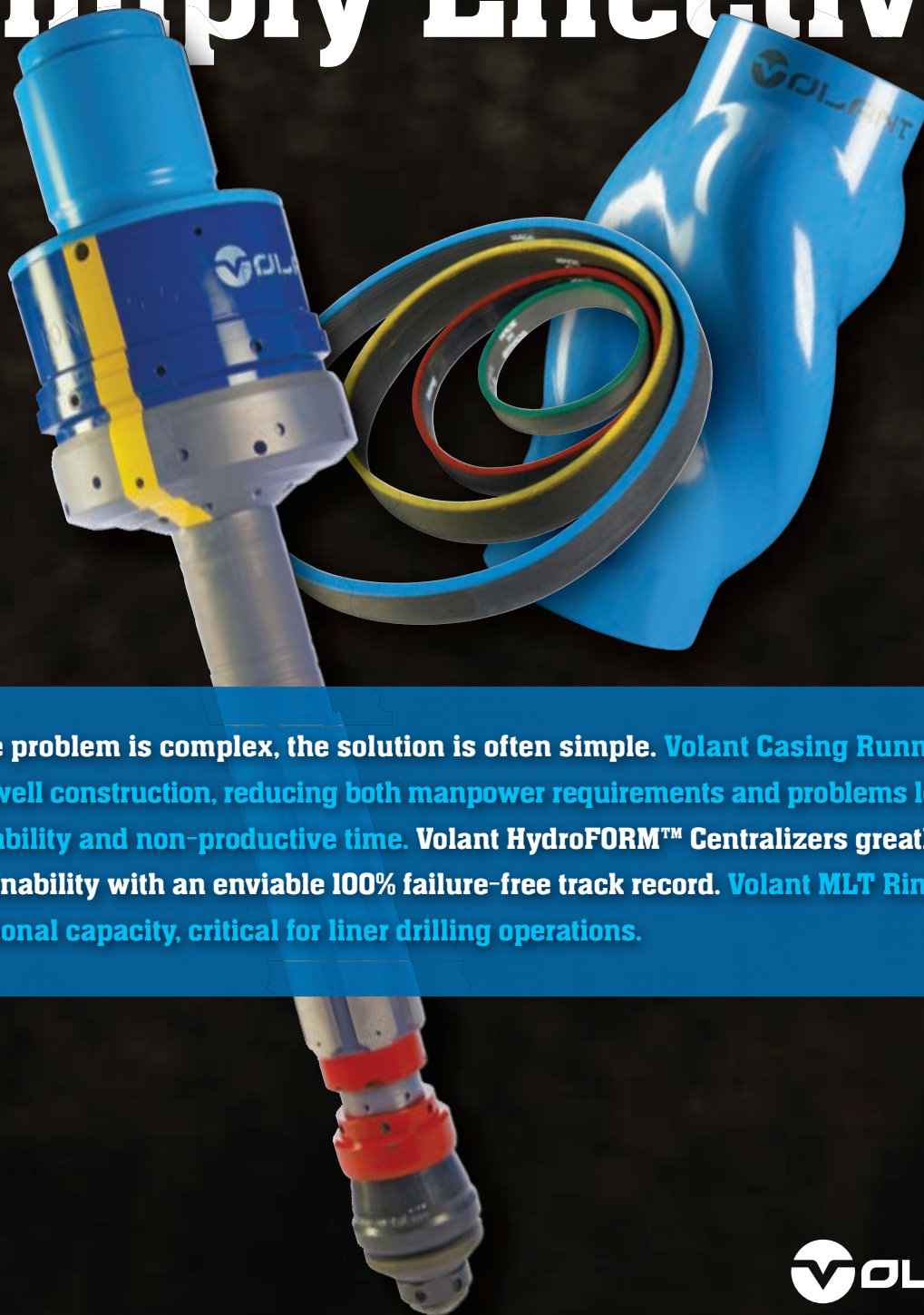
Phase II. A fine-scale structural 3D model was built for each well; these models were constructed using all the available information (well logs, 2D- and 3D-seismic data, petrophysical evaluations, and stratigraphic well tops). The first objective of this model is to complement logging while drilling (LWD) of the horizontal section. Additionally, to improve the efficiency of well placement, risks and time consumption for decisions made while steering the well were reduced by implementing real-time geological and petrophysical monitoring. The horizontal-drilling techniques applied incorporated the use of new technologies that allowed analysis of real-time data, which helped in making the best decisions to minimize risk and avoid a possible well-placement incident. Understanding the behavior and petrophysical properties of the formation being drilled is the main benefit of the real-time petrophysical evaluation, which will result in a quantification of formation quality in real time.

The structural model, coupled with the real-time geological and petrophysical monitoring, is used to determine whether the well trajectory is following the pay zone. The stratigraphic surfaces of the model can be updated with the in-

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 164545, “Unconventional-Reservoir Development in Mexico: Lessons Learned From the First Exploratory Wells,” by P.A. Parra, N. Rubio, C. Ramirez, B.D. Guerra, V.A. Exler, I.R. Campos, M.D. Trejo, J. Olguin, C.H. Vargas, R. Valbuena, D.F. Soler, M.I. Weimann, V. Lujan, and P. Bonningue, Schlumberger, and P.G. Reyes, R. Martinez, R. Muñoz, E. Rodriguez, and M. Garcia, Pemex, prepared for the 2013 SPE Unconventional Resources Conference—USA, The Woodlands, Texas, USA, 10–12 April. The paper has not been peer reviewed.

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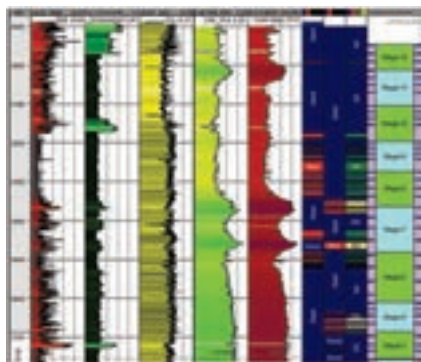


Fig. 2—Graphical representation of the stage design performed in the completion-adviser module.

formation coming from LWD, resulting in a more-realistic structural model (Fig. 1).

Once the horizontal well is already drilled and the petrophysical analysis, stratigraphic tops, and updated geomechanical model are obtained, the static model is updated and the petrophysical properties are populated. This updated model will then be used in the simulator for the hydraulic-fracture design.

Phase III. Reservoir-centric completion-and-stimulation software that integrates petrophysical and geomechanical data was used to optimize the completion and hydraulic-fracture design. Historically, staging has been performed geometrically, equally spacing perforation clusters along the lateral. However, recent studies suggest that placing perforations in rocks with similar properties will improve distribution of hydraulic fractures along the well and, therefore, increase well production. Therefore, staging design was performed by use of the completion-adviser module of the completion-and-stimulation software. An example of the output of the stage-design process can be observed in Fig. 2.

Once the staging has been defined, the hydraulic-fracture treatments are designed. The software used is capable of simulating the behavior of hydraulic fractures in unconventional reservoirs and considers the data gathered in all of the previous phases of the workflow. The simulations were performed for each stage, considering formation properties specific to that stage and along the length that the hydraulic fractures develop. Results of the simulations were observed in a 3D interface to evaluate coverage and

other required parameters along the lateral. Once the designs were finalized, the jobs were executed.

Phase IV. After the wells are opened to production, results are analyzed with various techniques. These include microseismic monitoring, production-history matching, production logging, and well testing. The results of each of these analyses are coupled with the data gathered during the execution of the fracture jobs to calibrate the model and update the hydraulic-fracturing simulations.

Application and Results

Of the six wells that were drilled and completed, the workflow was fully implemented in three and partially implemented in one. In Wells B_{EF}, D_{EF}, and A_P, both the drilling and the completion stages were implemented. In Well E_{EF}, only the completion stage of the workflow was implemented. The following paragraphs summarize the methodology applied and the results achieved in two of these wells (the complete paper contains this information for all four wells in which the workflow was involved).

Well B_{EF}. This well was placed near the borderline between the expected condensate and oil windows of the Eagle Ford shale. All phases of the workflow were applied on this well. The total measured depth (MD) was 10,400 ft, and the true vertical depth (TVD) was approximately 5,085 ft, with a lateral length of approximately 4,300 ft. The well was landed and navigated in the lower Eagle Ford shale with an azimuth mostly parallel to the expected minimum-horizontal-stress direction, where the estimated reservoir properties included the following:

- ▶ Pressure: 2,800 psi
- ▶ Temperature: 169°F
- ▶ Permeability: 200 nd
- ▶ Effective porosity: 1–8%
- ▶ TOC: 3–6%

In this case, the strategy was to navigate the well approximately 16 ft below the top of the lower Eagle Ford formation to contact both the lower and upper Eagle Ford formations with the hydraulic-fracture jobs. However, this also meant that the well was placed approximately 80 ft above the “sweet spot” identi-

fied in the petrophysical analysis of the lower Eagle Ford. To simulate the behavior of the hydraulic fractures properly, an anisotropic MEM was created to estimate the stress profile, which showed considerable differences when compared with the isotropic geomechanical model that is commonly used. The engineered completion design considered 14 stages with six perforation clusters per stage, except for Stages 7 and 8, where only four clusters were used. As mentioned previously, the perforation clusters were located along the lateral by considering similar rock properties. The first stage was perforated by use of an abrasive perforation system with coiled tubing, and the remaining stages were perforated by use of the plug-and-perforation technique with pump-down guns. All stages were hydraulically fractured by use of the channel-fracturing technique. The proppant types used were a combination of 40/70-, 30/50-, and 20/40-mesh white sand. The jobs were pumped at 55 bbl/min with 180,000 lbm of proppant per stage. A total of approximately 2,520,000 gal of fluid was injected in the well.

During the flowback period of approximately 40 days, and after having recovered approximately 20% of the fluid injected, the well showed intermittent production of gas and condensate, which stopped after 11 days. To analyze this behavior, the well was closed for 16.5 days and a buildup test was performed. Interpretation of the buildup test showed a well fractured with infinite-conductivity fractures along the lateral. It is suspected that the main reason for the poor production behavior of the well is that it was not landed in the sweet spot, but rather in poor-quality rock.

Well E_{EF}. This well was drilled inside the expected condensate window of the Eagle Ford shale. Only the last two phases of the workflow were applied on this well because it had already been drilled when analysis began. The total MD was 12,320 ft, and the TVD was approximately 6,772 ft, with a lateral length of approximately 4,900 ft. The well was landed and navigated in the lower Eagle Ford shale with an azimuth mostly parallel to the expected minimum-horizontal-stress direction. The estimated reservoir properties included the following:



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- ▶ Pressure: 4,000 psi
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- ▶ Effective porosity: 3–9%
- ▶ TOC: 3–5%

The engineered completion design considered 16 stages with five perforation clusters per stage. The perforation clusters were located along the lateral on the basis of similar rock properties. The first stage was perforated by use of an abrasive perforation system with coiled tubing, and the remaining stages were perforated by use of the plug-and-perforation technique with pump-down guns. The first eight stages were stimulated with slickwater fractures. Because of some pressure spikes observed during these stages, the remaining stages combined the use of slickwater and linear gel to place the proppant in the formation. The proppant types used were a combination of 100- and 40/70-mesh white sand. The jobs were pumped at 65 bbl/min with 350,000 lbm of proppant per stage. A total of approximately 5,160,000 gal of fluid was injected into the well. During the production test, the well had a peak gas production of 4.6 MMscf/D and a peak condensate production of 146 B/D, while flowing by 28/64- and 26/64-in. chokes, respectively. The average wellhead pressure was 2,265 psi.

Conclusions and Lessons Learned

- ▶ The integration of several disciplines is required to design and optimize unconventional shale wells properly.
- ▶ The workflow used improves the design, evaluation, and optimization of unconventional shale wells.
- ▶ The presence of hydrocarbons in the Eagle Ford and Pimienta formations was evidenced in all the wells where the workflow was applied.
- ▶ The production results suggested that proper landing and navigation of the well within the sweet spot of the target formation are key to achieving the expected production. **JPT**

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Unconventional-Asset-Development Work Flow in the Eagle Ford Shale

Development of the Eagle Ford shale typically consists of horizontal wells stimulated with multiple hydraulic-fracture stages. This paper presents a pragmatic integrated work flow used to optimize development and guide critical development decisions in the Black Hawk field. Geoscientists and reservoir and completion engineers worked collaboratively to identify optimal completion designs and well spacings for development focus areas. Multiple simplistic simulation models were history matched to existing production wells.

Introduction

In 2008, the operator drilled several successful wells in the Hawkville field of what would become the Eagle Ford shale play. Early results led to substantial land acquisition. The Eagle Ford, while continuous over wide sections, varies substantially in terms of fluid and rock properties. **Fig. 1** shows a cross section for an arbitrary line through Black Hawk and Hawkville to the Maverick basin, showing the relative changes in thickness and Young's modulus.

An understanding of the characterization of shale systems for simulation has evolved rapidly. Flow contributions from natural fractures, induced fractures, and matrix rock along with the nature of the hydrocarbon deposit itself should be considered. Perhaps even more important is regional variation. In the world of conventional assets, property estimation needs to be reliable only for

a small geographical area, often within one sandstone structure of a few square miles at most. This can be compared with the scale of the play in **Fig. 1**. For conventional reservoirs, standardized laboratory methods and years of research and trial and error have educated our approaches to well-defined best practices. In shale plays, these have not yet been fully worked through and adopted by consensus, often leaving the owner of the asset as the arbiter of methodology.

Work Flow

The work flow proposed in this paper follows the advice of Carveth Read, the British philosopher, regarding uncertainty: "It is better to be vaguely right than exactly wrong." Simple models with a multitude of geological scenarios are used to understand key drivers. From this starting point, the work can progress further through the complex and time-consuming approaches that can be performed only in a small subset of locations where data permit.

Fig. 2 shows the work-flow outline applied in the Eagle Ford fields to obtain timely estimates of reservoir response to spacing and completion design.

The fields were split into areas of geological and fluid similarity. For each area, a regional geocellular model was generated, incorporating local well-control, seismic, log, and core data. Within this region, an existing well with stable production history was selected for history matching. Average layer formation properties, areally upscaled to the estimated drainage region of the well, were

extracted from the model for reference-case description of the hydraulic-fracture and dynamic-simulation models.

Expected fracture geometries and conductivities for the historical well completion were estimated in hydraulic-fracture models. These results were used to guide the definition of explicitly modeled hydraulic fractures in the reservoir-simulation models. Multiple history-matched models were generated with computer-assisted-history-matching techniques.

The unique contribution of this work is to illustrate the basis for making development decisions considering the inherent uncertainty in the forecasts. The reference description of the formation and hydraulic fractures was made on the basis of the extracted properties of the geocellular and hydraulic-fracture models, respectively. Stochastic realizations from ranges of key properties in formation and completion parameters were tested.

The resulting calibrated reservoir scenarios formed the basis of optimization studies for development drilling and down spacing. Completion-design parameters were evaluated in hydraulic-fracture models. The resulting fracture geometries were simulated, and the optimum completion design and well spacing were determined for each area.

For a geological overview of the Black Hawk field and associated petrophysical and multimineral work flows, please see the complete paper.

Fit-for-Purpose Geologic Modeling in Shale Plays

Development in unconventional reservoirs currently relies on horizontal wells designed to stay within a defined target zone and to follow along strata as closely as possible. The reality is that geologic layers are not perfectly continuous and formations change laterally in thickness,

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 168973, "Unconventional-Asset-Development Work Flow in the Eagle Ford Shale," by David Cook, Kirsty Downing, Sebastian Bayer, Hunter Watkins, Vanon Sun Chee Fore, Marcus Stansberry, Saurabh Saksena, and Doug Peck, BHP Billiton Petroleum, prepared for the 2014 SPE Unconventional Resources Conference—USA, The Woodlands, Texas, USA, 1–3 April. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

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2

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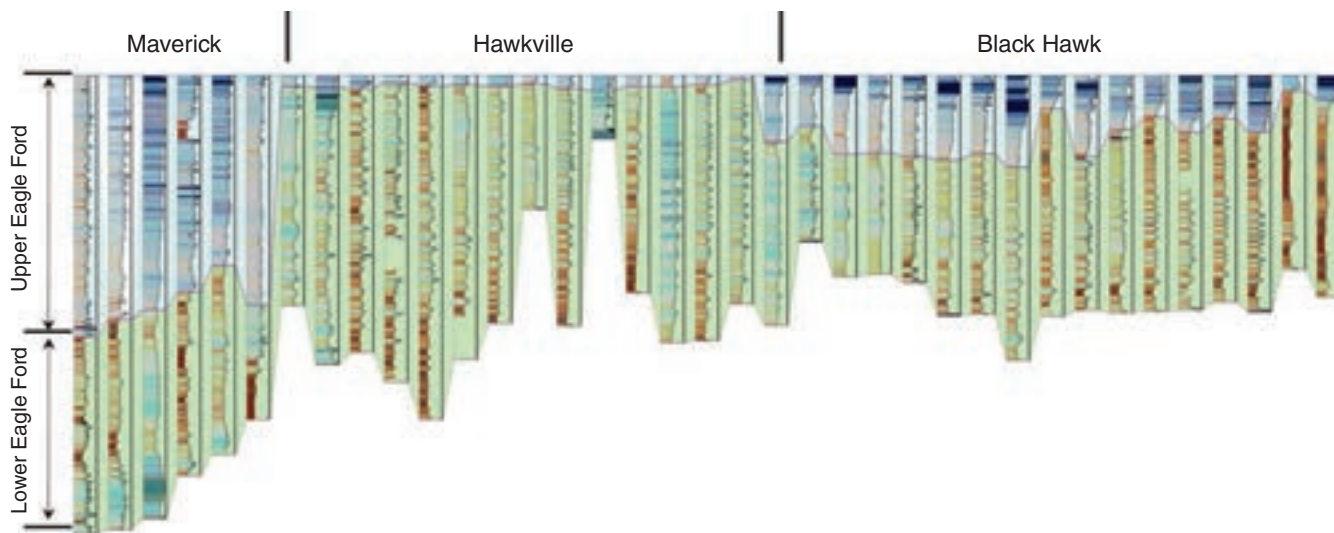


Fig. 1—Relative change in Young's modulus and reservoir thickness seen in an arbitrary line through Black Hawk and Hawkville to the Maverick basin (greater Young's modulus in kicks to the right).

properties, and structure, especially near folds and small faults. As the use of horizontal wells in excess of 3,000 ft becomes customary, lateral changes in the formation become even more important. One of the principal factors in the successful development of unconventional reservoirs is the proper spatial position of horizontal wells within the vertical section of the target reservoir. A simple work flow to account for changing reservoir and geomechanical properties was developed to assist modeling and geosteering of the wells.

A high-resolution version of the reservoir model was constructed that could be upscaled for flow simulation. The design geometry of the upscaled model was

based on the production well selected by the engineers for history matching in different areas in the field. The upscaled model incorporated all cells within the estimated drainage volume of the well, accounting for well orientation, length, and spatial position within the regional structural framework. The work showed that correct understanding of the position of the well relative to the gross interval of interest was often very important.

The framework of the geologic model was based on the preparation of robust regional structural maps tied to pilot and horizontal wells in the area and trended by depth-converted seismic horizons. Tops along the wells were quality controlled, with geologists geosteering

the wells. Accurate placement of all available horizontal wells permitted distribution of reservoir properties using all available data. Total porosity was distributed by use of upscaled logs that varied in vertical resolution from 3 to 5 ft, depending on the geologic section. The distribution was a sequential Gaussian simulation using depositional axis as a trend in the variogram. This axis varied for each location to be studied. Water saturation and permeability were distributed in a similar fashion, with the difference being that total porosity was used as a secondary trend. Each geomechanical unit had a separate distribution.

Using seven geomechanical units, simulation-model grids were designed on the basis of each one of the wells to be evaluated and the reservoir properties in the high-resolution model. Both the high-resolution static model and the upscaled models honor available core data and petrophysical analysis of wireline logs, guaranteeing that the petrophysical analysis is honored through the entire process. This work flow is different from commonly used conceptual models in that the models of the former are fully tied to the regional framework of the area and the depth from which the well to be analyzed originates, without the time requirements of most complex geomodels.

Applying this fit-for-purpose approach, two critical objectives were accomplished: improved characterization of unconventional reservoirs as

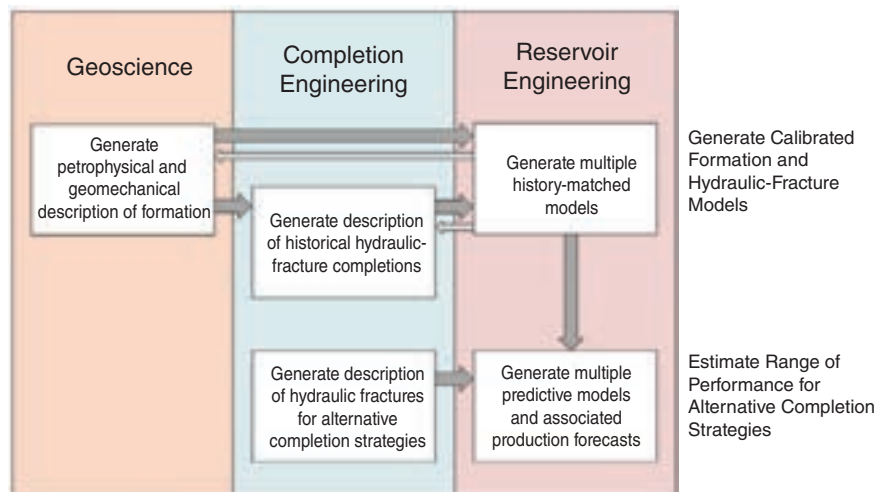


Fig. 2—Evaluation work flow.

development-drilling plans were updated to reflect the optimal well spacing for each lease, and development of an active reservoir-modeling work flow that was integrated into the reservoir-simulation efforts as they were occurring simultaneously.

Completion Strategy

Most completions in the Eagle Ford have been either crosslinked (XL) -gel or slickwater treatments. The operator elected to use XL-gel and XL-gel/channel-fracture stimulations on the basis of early experimentation in the Hawkville field. The majority of the wells to hold the acreage were completed with XL/gel-channel-fracture treatments. **Table 1** shows the critical variables and ranges in selection across operators in the play.

Well-spacing and completion optimization have a symbiotic relationship in development planning. Adjustments that potentially extend effective fracture half-length will have a direct link to the optimal wellbore spacing for the section. Therefore, evaluation of the optimal economic outcome must start with op-

timization of the well for efficiency and half-length followed by spacing. Completion efficiency can be summarized as increasing net present value per barrel while maintaining efficient use of the land available for development.

Hydraulic-Fracture Modeling

Two modeling approaches were taken to estimate proppant placement. One of the established 3D planar-fracture models was used in conjunction with a finite-element geomechanical model. Both of these models present challenges in their interpretation. 3D planar models seek to model the effects within the fracture accurately. While stress shadow-

ing between clusters is considered, the compromise is that the model requires the fracture to be always planar, an assumption almost always never fully met. Complexity seen often makes half-length achieved by a planar-fracture model optimistic; therefore, this was used as a best case for length of propped section in the simulation work. In addition, half-lengths predicted from the model were compared with half-lengths calculated from rate-transient analysis and tracer surveys taken when wells were stimulated. The finite-element geomechanical model was used to look at stress changes from offset wells and to optimize cluster spacing. The downside to the finite-

TABLE 1—TYPICAL EAGLE FORD COMPLETION PARAMETERS ACROSS ALL OPERATORS

Variable	Typical Range
Stage spacing	200–400 ft
Cluster spacing	40–100 ft
Carrier fluid	Slickwater/XL/high-temperature gels
Proppant volume	150,000 to greater than 500,000 lbm



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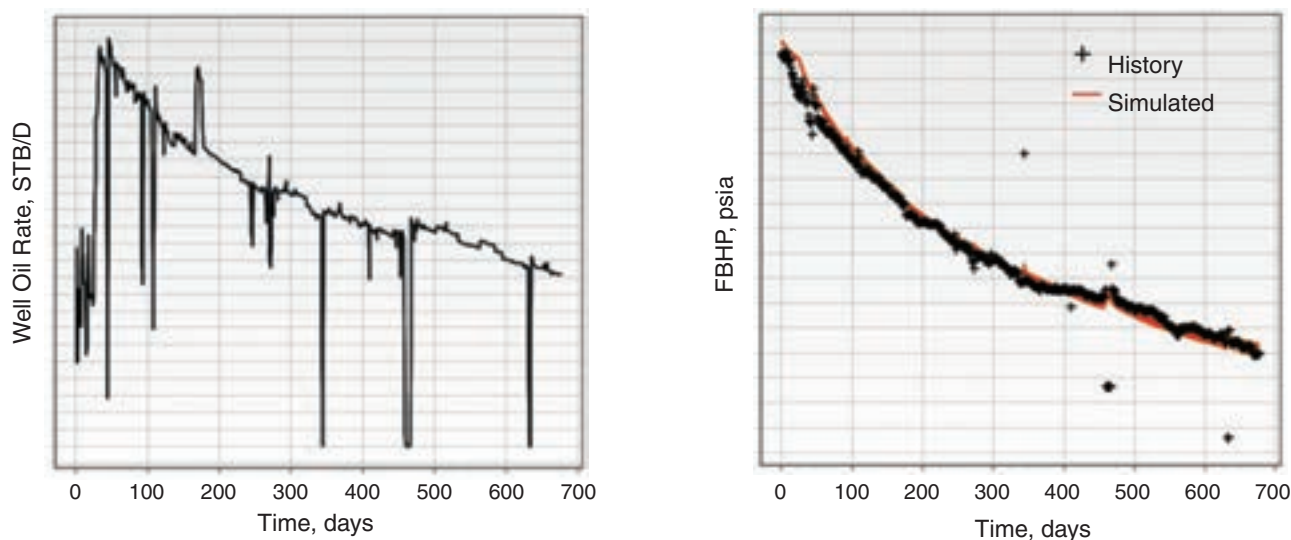


Fig. 3—Example history matches. Well constrained on rate and matched on flowing bottomhole pressure (FBHP).

element geomechanical models commercially available is their inability to model the proppant placement within the created fracture and other critical parameters such as width and height growth. Therefore, these two approaches complement one another, and are in fact both rather limited without other information.

Stochastic Simulation

Multiple simplistic simulation models were history matched to existing production wells. For each well, key reservoir uncertainties, including effective permeability, permeability reduction with pressure, original hydrocarbons in place, and formation compressibility, were allowed to vary. Porosity was modeled as effective porosity, excluding the volume of adsorbed hydrocarbons estimated to be present.

The models were defined with an effective permeability that accounts for the possible influence of natural fractures. Permeability reduction with pressure was found to be a critical parameter in the estimation of ultimate recovery. Core-based measurements of permeability vs. net confining stress were converted to permeability vs. pressure and were included in the simulations in the form of a gamma (or permeability-modulus) function.

Wells selected for history matching ranged from dry gas to near-critical gas/condensate. Fluid properties were modeled with equation-of-state models, tuned to available pressure/volume/temperature data and extrapolated from sampled wells on the basis of trend maps of produced-condensate yield.

Completion parameters, including fracture conductivity and half-length of dominant and minor fractures, were also tested. For each run, the fracture geometry as predicted from the hydraulic-fracture model was preserved, while the

length, conductivity, and fracture efficiency were varied.

Initial fracture conductivity was estimated from fracture width and proppant concentration predicted by hydraulic-fracture modeling. Initial conductivity was then modified to account for changing stress and production conditions, including embedment, crushing, and spalling effects. The models were found to be relatively insensitive to the predicted range of fracture conductivity because of the large contrast in flow capacity between the hydraulic fractures and the formation in all scenarios.

Assisted-history-matching methods were used to explore the solution space within the defined uncertainty ranges and identify all possible parameter sets that can match production history (Fig. 3). The alternative history-matched cases were used as the basis for predictive modeling, enabling a robust range of forecast outcomes.

The history-matching process provided a means of calibrating both the geocellular and hydraulic-fracture models. The original uncertainty estimates were narrowed where the full range of inputs was demonstrated not to honor the field data. Alternative reservoir descriptions, validated through history matching, provide the basis for well optimization. For each run, a selection of history-matched realizations was used to test alternative completion designs and the impact of well spacing. **JPT**



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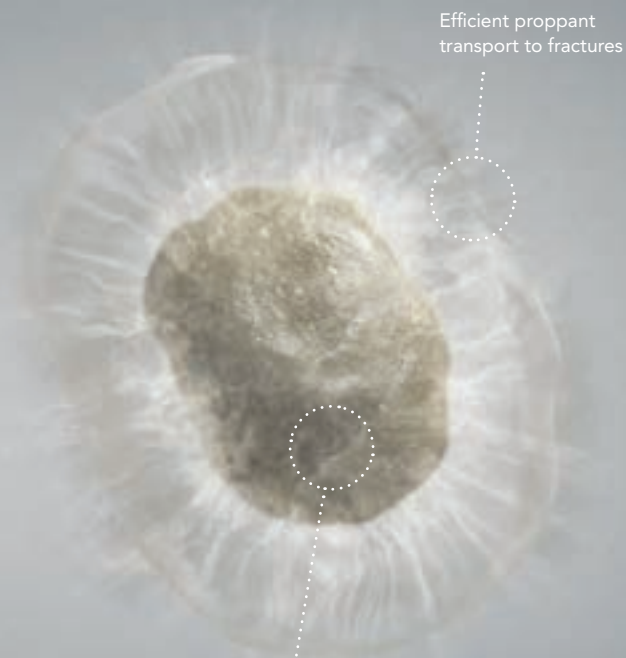


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Recovery Research Center (PRRC), a research division of the New Mexico Institute of Mining and Technology (NMT). He is also an adjunct professor for the Petroleum Department at NMT. Grigg has been coprincipal investigator of the Southwest Regional Partnership on Carbon Sequestration since 2007. He holds a PhD degree in physical chemistry from Brigham Young University. Grigg's major topic of work for nearly 35 years has been enhanced oil recovery (EOR), with emphasis on CO₂ EOR and increasing focus on carbon storage during the last 15 years. He has authored or coauthored more than 100 publications and serves on the JPT Editorial Committee.

Recommended additional reading at OnePetro: www.onepetro.org.

SPE 169047 Study of Particle-Structure and Hydrophobicity Effects on the Flow Behavior of Nanoparticle-Stabilized CO₂ Foam in Porous Media by Jianjia Yu, New Mexico Institute of Mining and Technology, et al.

SPE 169045 Efficient Experimental-Data Acquisition for Miscible CO₂ WAG-Injection Corefloods in Carbonate by Sebastien Duchenne, Total, et al.

OTC 24454 Diffusion Coefficient of CO₂ in Light Oil Under Reservoir Conditions Using X-Ray Computed Tomography by S.V. Araujo, State University of Campinas, et al.

SPE 169049 Integration of Reservoir Simulation and Time-Lapse Seismic in Delhi Field: A Continuous-CO₂-Injection EOR Project by T. Chen, Colorado School of Mines, et al.

CO₂ applications

The mass of carbon dioxide (CO₂) use for enhanced oil recovery (EOR) and of the subsequent oil produced has continued to increase almost every year for more than 40 years. Most of the volume and growth continue to be in North America, though pilots and rumblings and rumors of additional CO₂ EOR projects continue throughout the world. Especially with all the verbiage about sequestering and storing anthropogenic CO₂, the talk continues in every corner. Even though the majority of the injected CO₂ in North America is natural CO₂, the mass of CO₂ injected into geologic formations from anthropogenic sources in North America (e.g., coal liquefaction in North Dakota; gas-processing plants in Wyoming and Texas; and fertilizer and ethanol plants in Kansas, Oklahoma, and Michigan) dwarfs that of the rest of the world. This will probably not always be the case as projects come on stream and especially as CO₂ becomes available. The hang-up is the availability of affordable CO₂.

The future of CO₂ in the industry is bright. Research continues on many fronts. The most appealing is the research to improve the present use in medium-grade-oil reservoirs beyond water alternating with CO₂ (WAG), through thickeners, nanoparticles, and surfactants to decrease mobility. Other methods to improve CO₂ usage include monitoring techniques to determine location and flow patterns of CO₂. New areas are opening up through horizontal drilling with fracturing techniques. Also, research is continuing to consider increased use where reservoir crude and CO₂ are not miscible at attainable reservoir conditions, such as in shallow reservoirs or with heavier oils. It is in these areas, where present technologies provide limited recovery, that CO₂ application is poised to become a possible avenue for increased oil recovery.

The availability of CO₂ is the greatest barrier to many potential CO₂-EOR projects. It has been shown that CO₂ is always technically successful because CO₂ will increase oil production for essentially every situation. The effort to identify CO₂ sources and improve capture technology is continual, in order to lower the source cost of CO₂ in relationship to the price of crude to improve economics. Work continues to improve our understanding of CO₂ recovery mechanisms and to develop strategies to take advantage of the properties of CO₂ and crude oils. In addition to EOR, the use of CO₂ to improve gas production from gas reservoirs and to retrieve gas from unminable coalbeds continues and should be encouraged. **JPT**

Gelled Emulsions of CO₂, Water, and Nanoparticles

Enhanced oil recovery (EOR) by carbon dioxide (CO₂) injection is an effective method for recovering additional oil beyond waterflooding. However, the CO₂-EOR process is handicapped, especially in thick reservoirs, by CO₂ gravity override. Because of density differences between the injected CO₂ and resident fluids in the reservoir, the lighter CO₂ tends to rise to the top of the reservoir, thereby bypassing some of the remaining oil. This paper investigates the use of gelling CO₂/water emulsions, stabilized by silica nanoparticles, to control the mobility of CO₂.

Introduction

The CO₂-EOR process, while increasingly important, is handicapped by several challenges. The first challenge is the gravity override of the injected CO₂ because of density differences between the injected CO₂ and resident fluids in the reservoir. The second is viscous fingering caused by the lower viscosity of the injected CO₂. Typical dense CO₂ viscosity at reservoir conditions is in the range of 0.05–0.1 cp, which is much lower than the viscosity of resident oil and brine. The resulting unfavorable mobility ratio leads to viscous fingering, causing early CO₂ breakthrough, high CO₂-usage factors, poor sweep efficiency, and low overall oil recovery. The third challenge associated with CO₂ EOR is reservoir geology and heterogeneities, including high-permeability streaks and fractures that can impact the sweep efficiency of a CO₂-EOR flood. Most of these

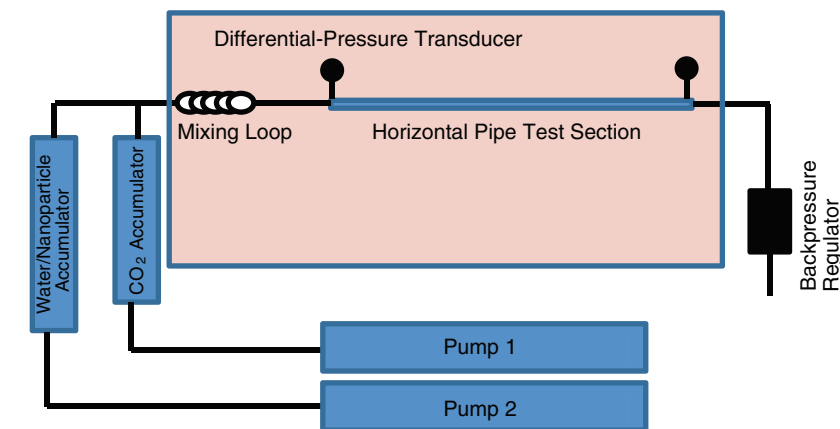


Fig. 1—Schematic of flow loop used for rheological experiments.

challenges have been countered by use of water-alternating-gas (WAG) processes. Although the WAG process improves the mobility of CO₂, it loses its effectiveness in controlling CO₂ mobility deep into the reservoir and beyond a certain distance from the wellbore.

This paper discusses another technique that provides an excellent alternative to WAG to control CO₂ mobility: the CO₂/foam emulsion. The main purpose of using CO₂ foams is to increase the viscosity of the CO₂ and therefore reduce its mobility through the reservoir. This emulsion is generated with water-soluble surfactants, CO₂-soluble surfactants, or nanoparticles. This paper investigates the use of gelling CO₂/water emulsions, stabilized by silica nanoparticles, to control the mobility of CO₂.

Experimental Studies

Materials. Fumed and colloidal silica nanoparticles were used in this study.

These nanoparticles have a silylating agent that renders them CO₂-philic.

The chemical-screening experiments were conducted to explore the possibility of generating both water-in-CO₂ (W/C) and CO₂-in-water (C/W) emulsions. Iso-octane (I-C₈) was used as a proxy fluid to represent supercritical CO₂ (SC CO₂) in the screening experiments. I-C₈ has density and solvency characteristics comparable with those of SC CO₂. Many noted experts have used I-C₈ to represent SC CO₂ in the area of CO₂ EOR. The water used to prepare different emulsion systems was seawater with a salinity of 57,000 ppm. CO₂ was locally supplied and had 99.99% purity. It was compressed to 5,000 psi in high-pressure titanium cylinders and used as SC CO₂.

Foam-Stability Test. Two types of emulsions were prepared on the basis of the degree of nanoparticle hydrophobicity. The first type was prepared by emulsifying water in I-C₈ containing hydrophobic particles at different weight percentages, while the other type was prepared by emulsifying I-C₈ in water containing hydrophilic nanoparticles. The nanoparticle weight percentage varied between 0.5 and 2 wt%, and the I-C₈-phase volume varied between 50 and 90%. The

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 166072, "Gelled Emulsions of CO₂/Water/Nanoparticles," by Fawaz M. Al-Otaibi, Sunil L. Kokal, Yun C. Chang, Jassi F. Al-Qahtani, and Amin M. Al-Abdulwahab, Saudi Aramco, prepared for the 2013 SPE Annual Technical Conference and Exhibition, New Orleans, 30 September–2 October. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

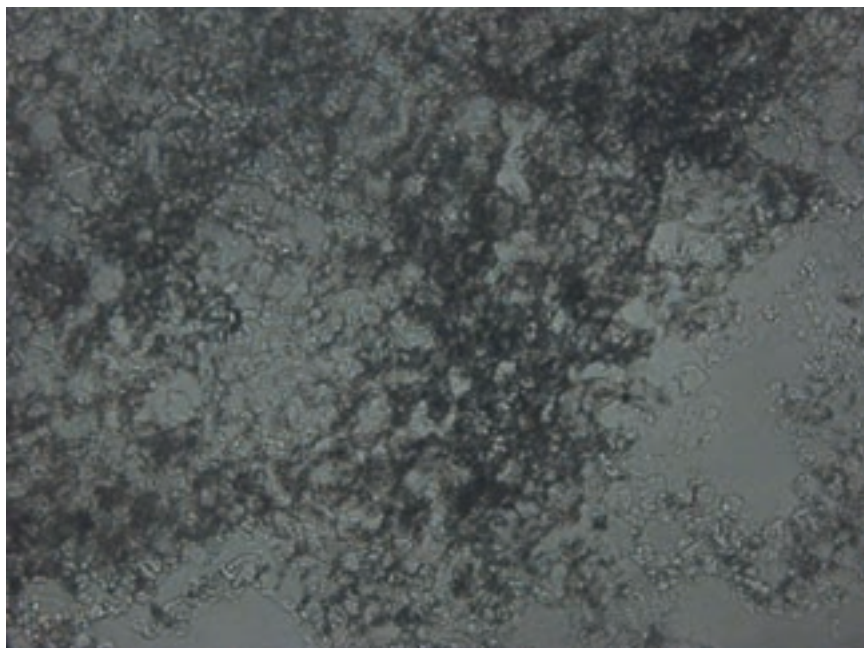


Fig. 2—Gel formation following I-C₈/water emulsion generation at 0.5 wt% silica nanoparticles, 50:50 I-C₈/water volume ratio, and 25°C.

morphology of stable emulsion (i.e., the dispersed-phase size and size distribution) was characterized by using an optical microscope fitted with a digital camera. This test was performed in two stages: room and reservoir conditions.

The high-pressure experiments were conducted with CO₂ and involved the use of specialized equipment able to handle pressure and temperature as well as having a viewing window for the observation of foam.

Viscosity Measurement

Following the stability screening tests, several experiments were conducted to investigate the increase of CO₂ viscosity after generating water/CO₂ emulsions using different nanoparticles. These experiments were conducted with a flow loop (Fig. 1). This flowloop is equipped with two accumulators, two pumps with a maximum pressure of 5,000 psi, a horizontal pipe section with an inside diameter of 6.99×10^{-4} m and a length of 1.5 m, a mixing loop, two differential-pressure transducers, and an oven. A backpressure of approximately 1,800 psi and a temperature of 200°F were maintained in all experiments.

Different water/CO₂ emulsions were injected into the flow-loop apparatus, and pressure values across the horizontal pipe section were recorded. These

emulsions were generated by use of different water/CO₂ volume ratios and with nanoparticle concentrations of 0.5, 1, and 2 wt%. To generate a certain water/CO₂ emulsion system, liquid CO₂ and nanoparticle solutions of desired concentrations were pumped by use of two separate pumps. These two fluids were mixed in the mixing loop, where the emulsion was generated. With a total injection rate of 20 cm³/min, the volume percentage of both CO₂ and water in the emulsion system was varied by controlling the injection rate of both water and CO₂.

Results and Discussions

Several experiments were conducted to explore the possibility of generating both W/C and C/W emulsions with either colloidal or fumed silica nanoparticles. The volume ratios between I-C₈ and water were varied. The I-C₈/water emulsion-generation experiments were performed by use of two main silica-nanoparticle systems: fumed silica and hydrophilic colloidal silica.

Foam Generation. Water/I-C₈ emulsions were generated using two types of fumed silica nanoparticles. The nanoparticles are 100% hydrophobic, with equivalent surface areas of 200 m²/g. One type has a particle size of 16 nm, while the other has a 12-nm particle size. The concentration

of these two silica nanoparticles was varied between 0.5 and 2 wt%. In addition, the I-C₈ volume percentage ranged between 50 and 90%. Initially, water/I-C₈ emulsions were generated successfully at different nanoparticle concentrations of 0.5 to 2 wt% and I-C₈ volume percentages of 50, 70, and 90%. The average size of water droplets in these emulsions generated by use of either type of nanoparticle was found to be nearly 35 μm. These results indicated that nanoparticle size had little or no effect on water-droplet size in the water/I-C₈ emulsions. The stability results for water/I-C₈ emulsions generated using either type of nanoparticle are comparable. Given the fact that the two types of nanoparticle have different particle sizes, it can be concluded that emulsion stability was not affected by nanoparticle size.

The stable-emulsion height percentage of the water/I-C₈ emulsion increased as the volume ratio decreased in the emulsion system. The nanoparticle concentration also affected the stability of water/I-C₈ emulsions. Increasing the nanoparticle concentration resulted in a more-stable emulsion system for the 90:10 I-C₈/water emulsion. Another interesting phenomenon observed in these emulsions is the formation of gel because of the interaction of silica nanoparticles, as shown in Fig. 2. The formation of gels should assist further in controlling CO₂ mobility during CO₂-EOR applications.

Effect of Hydrophobicity Degree and Silica Type. To assess the effect of both hydrophobicity degree and silica type on the water/I-C₈ emulsions, another set of experiments was conducted using a colloidal silica. These silica nanoparticles are 100% hydrophilic, with an average particle size of 22 nm and a surface area of 140 m²/g.

I-C₈/water emulsions were generated with the colloidal silica nanoparticles. The emulsions formed using these nanoparticles were not stable. At 90% I-C₈ volume percentage, no emulsions were generated even when the colloidal-silica-nanoparticle concentration was increased to 2 wt%. Relatively speaking, the I-C₈/water emulsions were more stable at lower I-C₈ volume percentage (Fig. 3). For example, the stable-emulsion height percentage was 35 and increased to 58

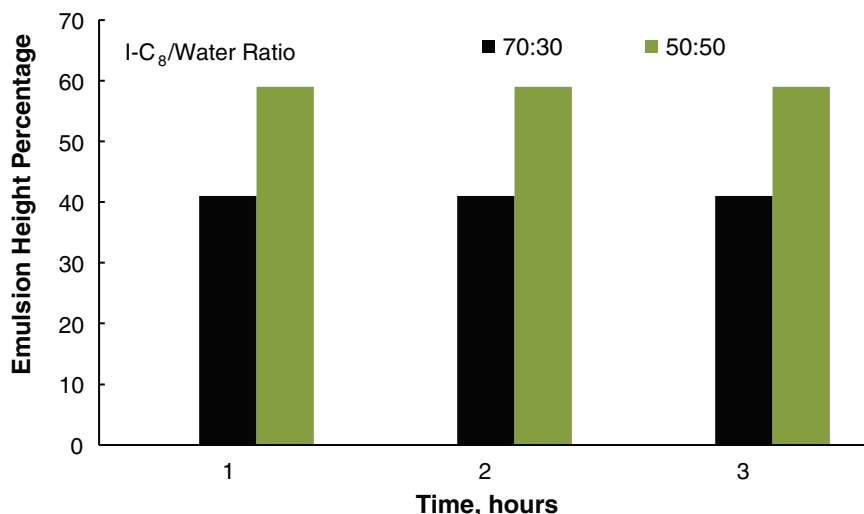


Fig. 3—Stability results for I-C₈/water at 1 wt% silica nanoparticles and 25°C.

when the I-C₈ volume percentage was decreased from 70 to 50% after 2 hours. The phenomenon of gelled emulsions was also noted in the I-C₈/water emulsions. The degree of gelation was stronger at higher nanoparticle concentrations.

Foam Viscosity. The emulsion viscosity was measured using the flow loop described previously. The viscosity, at a fixed flow rate, is approximated with the pressure drop across the flow loop. In reality, emulsions are known to be non-Newtonian fluids; their viscosity is dependent on shear rate. The CO₂/water emulsions are also compressible, and their density is dependent on applied pressure.

At constant flow rate, many empirical equations have been proposed to correlate fluid-flow behavior to its physicochemical properties, such as density and viscosity. For a discussion of some of these equations, please see the complete paper.

The maximum theoretical emulsion density was 634.8 kg/m³ and the maximum obtained Reynolds number was 147.9, confirming that all experiments were conducted under laminar flow. CO₂/water emulsion viscosity using both fumed silica nanoparticles was comparable and had similar profiles, indicating that nanoparticle size had no significant effect on the rheological properties of the generated emulsion.

At constant CO₂/water volume ratio, the emulsion viscosity increased when nanoparticle concentration was increased.

The highest increase in the viscosity of CO₂/water emulsion attributable to the increase of nanoparticle concentration was noticed at a 50:50 CO₂/water volume ratio. When the nanoparticle concentration was increased from 0.5 to 2 wt%, the CO₂/water emulsion viscosity increased by 40, 55, and 83% at 90:10, 70:30, and 50:50 CO₂/water volume ratios, respectively.

At constant nanoparticle concentrations, it was noticed that the highest emulsion viscosity occurred at a 50:50 CO₂/water volume ratio. The highest effect of increasing the CO₂/water volume ratio was noticed at a nanoparticle concentration of 2 wt%. An increase of 60% in the CO₂/water emulsion viscosity was noticed at 2 wt% of nanoparticles when the CO₂/water volume ratio was decreased from 90:10 to 50:50.

Conclusions

Several experiments were conducted to explore the possibility of generating both W/C and C/W emulsions using either colloidal or fumed silica nanoparticles. In these experiments, the immiscible two-phase water/I-C₈ fluid was used to represent a water/CO₂ system. The main conclusions from these experiments include the following:

- ▶ Stable water/I-C₈ emulsions were generated using different concentrations of hydrophobic silica nanoparticles and different water/I-C₈ volume percentages.
- ▶ The nanoparticle concentrations and water/I-C₈ percentages had an impact on the stability

of formed emulsions of I-C₈ and water.

Another set of experiments was conducted using liquid CO₂ to explore the possibility of generating CO₂/water emulsions and to investigate the rheological properties of these emulsions. The main conclusions of these experiments include the following:

- ▶ Stable C/W and W/C emulsions were generated at different CO₂/water volume ratios using different concentrations of hydrophilic and hydrophobic silica nanoparticles, respectively.
- ▶ Generating CO₂/water emulsion was very effective in enhancing the viscosity of liquid CO₂.
- ▶ At constant CO₂/water volume ratio, the emulsion viscosity increased when the nanoparticle concentration was increased.
- ▶ At constant nanoparticle concentration, the emulsion viscosity increased when the CO₂ volume percentage was decreased. **JPT**

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Enhanced Recovery in Unconventional Liquid Reservoirs by Use of CO₂

Technological advances in multiple-stage hydraulic fracturing and horizontal drilling have improved the overall profitability of oil-shale plays by enhancing matrix/wellbore connectivity. However, as the reservoir matures, primary-production mechanisms no longer drive oil to the hydraulic fractures, making the improvement of matrix/wellbore connectivity insufficient to provide economically attractive production rates. This study presents experimental results on the use of carbon dioxide (CO₂) as an enhanced-oil-recovery (EOR) agent in preserved, rotary sidewall reservoir core samples with negligible permeability.

Introduction

CO₂ is a powerful agent for EOR. It reaches miscibility at lower reservoir pressure compared with nitrogen and hydrocarbon gases, swells the oil, reduces oil viscosity, and reaches supercritical state at the pressure and temperature of most oil reservoirs, resulting in oil-like density that reduces override effects. Moreover, CO₂ has been reported to be successful during field applications under unfavorable conditions such as those found with heavy-oil reservoirs and oil-wet naturally fractured reservoirs, where waterflooding is largely unsuccessful. The purpose of this investigation is to evaluate CO₂ EOR in unconventional liquid reservoirs with lower permeability than that reported previously. We used preserved sidewall

shale cores saturated with oil and with permeability in the nanodarcy range, preventing us from performing CO₂ flooding as conventionally conceived because CO₂ could not be injected directly into the matrix. We developed a technique to pack the sidewall core samples into the core holder, using glass beads to simulate the presence of a hydraulic fracture. With this approach, we did not have to cut the cores and we did not alter the rock properties and the original fluid saturation. The core was soaked in CO₂ for several days, and production was allowed in intervals. Changes in saturations were tracked with X-ray computed tomography (CT). Analysis of the images revealed that CO₂ was able to penetrate the cores, resulting in an oil recovery estimated in the range of 18 to 55% of original oil in place (OOIP).

This paper discusses the results on the basis of viscous-displacement, diffusion, and solubilization mechanisms. Additionally, the paper draws a research path using numerical simulation and laboratory experiments to evaluate the potential of these mechanisms to determine if they can support an economical continuous-CO₂-injection process in reservoirs where conventional flooding cannot be performed because of adverse rock properties, and it compares that scenario on the basis of recovery and economics with a huff 'n' puff CO₂ injection.

Equipment and Procedures

Two experiments were conducted in this investigation. The temperature was 150°F



Fig. 1—Preserved sidewall Cores 1 and 2 after the first experiment.

for both experiments. The pressure was 3,000 psi in the first experiment and 1,600 psi in the second. Two preserved sidewall shale cores saturated with oil were used in each experiment (Fig. 1). The petrophysical properties of the rock are unknown, but rock permeability is so low that CO₂ injection through the matrix was not possible. Therefore, conventional procedures to clean the cores, measure their pore volume, and resaturate them with produced oil were dismissed, a situation that prevents us from presenting balances of injected and produced fluids and accounting properly for recovery. Table 1 presents the conditions of the experiments and the dimensions of the cores used.

The presence of a hydraulic fracture was simulated by surrounding the cores with high-permeability media created from glass beads. This approach was selected for several reasons. The high-permeability media ensured that pure CO₂ at high pressure was in contact with the shale rock at all times, which almost eliminated compositional effects; the CO₂ volume in the fracture was several orders of magnitude higher than the pore volume of the core samples. This approach was chosen over cutting the core in half in order to avoid altering the core during the cutting process. The cutting element alters the rock properties by polishing the rock surface and reduc-

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 169022, "Experimental Investigation of Enhanced Recovery in Unconventional Liquid Reservoirs by Use of CO₂: A Look Ahead to the Future of Unconventional EOR," by Francisco D. Tovar, SPE, Texas A&M University; Øyvind Eide, SPE, and Arne Graue, SPE, University of Bergen; and David S. Schechter, SPE, Texas A&M University, prepared for the 2014 SPE Unconventional Resources Conference, The Woodlands, Texas, USA, 1–3 April. The paper has not been peer reviewed.

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TABLE 1—EXPERIMENTAL CONDITIONS AND CORE DIMENSIONS

	First Experiment		Second Experiment	
Temperature (°F)	150		150	
Pressure (psi)	3,000		1,600	
Core number	1	2	3	4
Core diameter (cm)	2.53	2.53	2.53	2.52
Core length (cm)	3.97	3.48	3.62	3.29
Core bulk volume (cm ³)	19.94	17.50	18.20	16.42

ing permeability. Also, the fluid used during the cutting process can imbibe into the matrix, causing important alterations because of the small pore volume. The approach selected in this investigation correctly represented the physics of a hydraulic fracture.

Two clean Berea sandstone samples acted as filters at either end of the setup to prevent the glass beads from entering the production tubing. Polytetrafluoroethylene shrink tubing confined the outside of the core setup. The core assembly was mounted in a Hassler-type core holder. The core holder was placed in a water bath that was heated to reservoir temperature; an even temperature was kept by circulating heated water continuously.

The whole assembly was mounted inside a medical CT scanner to monitor changes in density. Distilled water was used as confinement fluid, and the pres-

sure was kept 250 psi above the reservoir pressure. A dome-loaded backpressure regulator kept the reservoir pressure at 3,000 psi during the first experiment and at 1,600 psi during the second experiment. The system was pressurized to 100 psi below the backpressure with CO₂, which was injected through an accumulator. When the desired pressure and temperature were reached, the system was isolated. Twice a day, the pressure in the system was increased to above the backpressure, resulting in production of CO₂ and any oil from the core samples. After approximately 1 hour of production, the pressure was again stabilized to a level immediately below the backpressure. Thus, production was allowed in stages. This approach was chosen because of the high volume of CO₂ compared with the pore volume of the core samples. The CO₂ saturation in the

high-permeability media is therefore assumed to be close to unity throughout the experiments. CT scans were taken at approximately 6-hour intervals to observe any changes in the density of the system. Fig. 2 shows a schematic of the displacement equipment.

Results

Oil Recovery and Core Mass Increment.

In each of the experiments, approximately 0.4 cm³ of oil was recovered. As discussed previously, porosity of the cores is unknown, and therefore OOIP and recovery factor cannot be calculated. To estimate the performance of CO₂ for EOR in these cores, we set up a number of scenarios. Porosity was given a range from 0.3 to 0.6% on the basis of published data from the field from which the cores were taken. No evidence of water saturation was found during the course of our experiments because no water production was observed. However, the presence of water in the core was not discarded because the mechanism responsible for the oil production in these experiments was not suitable for water production. Therefore, a range for initial water saturation from 0 to 30% was considered.

Recovery factor was high, ranging from 18 to 51% for the first experiment

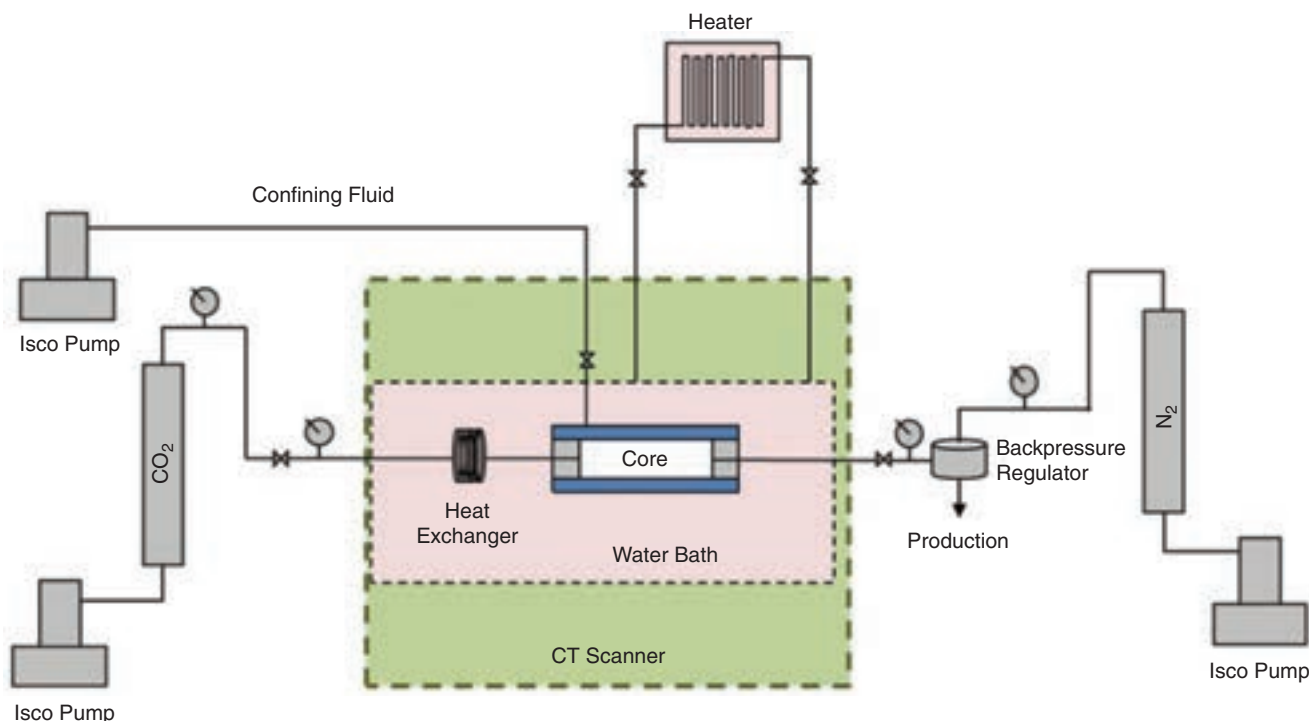


Fig. 2—Schematic of the displacement equipment.

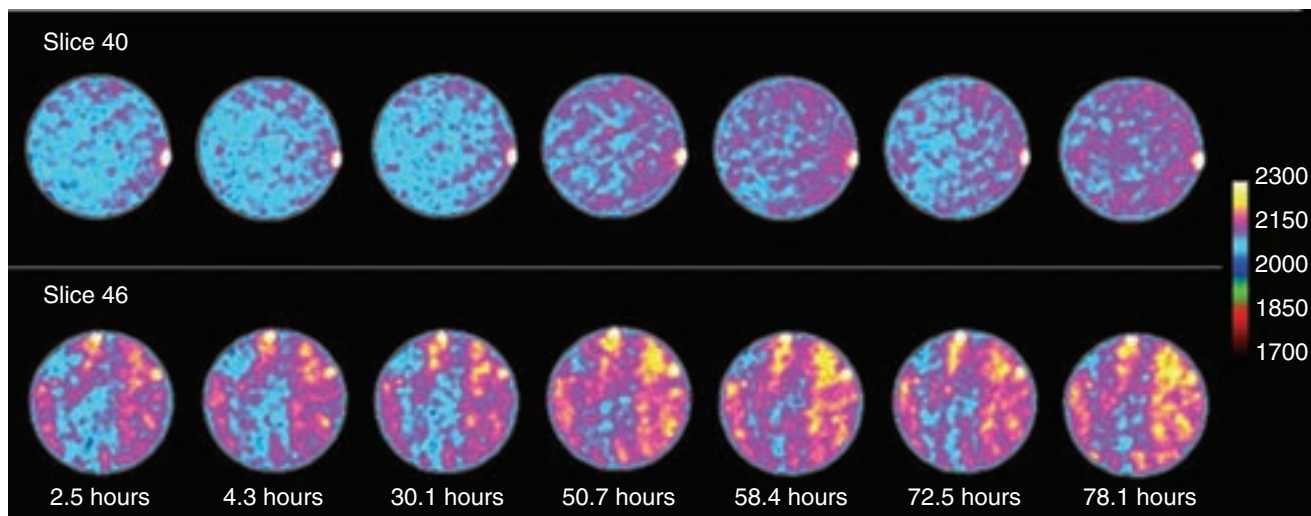


Fig. 3—CT images for Slices 40 and 46 of Core 2 during the first experiment. The images show the change in CT number as a function of time.

and from 19 to 55% for the second experiment. The oil recovered during both experiments had a lighter color than the oil produced from the source field and seemed to have low viscosity, suggesting vaporization of the hydrocarbons into the CO₂ as a recovery mechanism.

The mass of the cores changed during the experiments. In the first experiment, Core 1 increased its mass by 0.07 g (from 50.48 to 50.55 g), while Core 2 increased its mass by 0.06 g (from 45.39 to 45.45 g). A decrease in mass as a result of the production of crude oil was expected. This unexpected result was attributed to the adsorption of CO₂ on the organic matter contained in the cores.

CT-Number Behavior. The attenuation of X-ray intensity when passing through a material is a function of the density and composition of such material and is expressed as a CT number. For high-energy scans, density dominates over composition. The change in CT number was tracked over time during both experiments.

During the first experiment, Cores 1 and 2 showed an increase in CT number, which can be correlated with increase in density. At 3,000 psi and 150°F, CO₂ has higher density than the hydrocarbon components that are likely the main constituents of the crude oil, and the increase in CT number is an indication that CO₂ is able to penetrate the preserved sidewall core over time, causing an overall increase in density.

The analysis of the CT images also reveals that CO₂ is making changes in the cores over time. A six-color palette was used to highlight where, in the core samples, the changes in CT numbers took place. The heterogeneities of the core sample were visible, and the color alterations occurred along the bedding planes, indicating that the penetration of CO₂ into the core is influenced by rock properties and fluid-saturation patterns.

The increment in CT number is small because it follows the change in density, and the density difference between the hydrocarbons and the CO₂ at 3,000 psi is not large. The authors concluded that during the soaking process, CO₂ dissolves into the oil, and the lighter hydrocarbon components are vaporized into the CO₂, as suggested by the appearance of the oil recovered and the CT images. The images do not show a displacement of one color by another, but a continuous change in which one color seems to fade into the next.

Fig. 3 shows CT images for Core 2 used during the first experiment. This sidewall core is more homogeneous than Core 1 and does not show bedding planes, but the increment in CT number is also evident as the images gradually change from sapphire blue to pink.

To confirm the results of the first experiment, a second experiment was performed. In the second experiment, the density difference between the CO₂ and the crude oil was increased, with the crude oil being the denser fluid. The

reservoir pressure was set at 1,600 psi, and the temperature was kept the same (150°F), resulting in a density of CO₂ significantly lower than that seen in the previous experiment, and below the density of the selected group of hydrocarbons. The change in density caused the CT-number trend to be reversed compared with the first experiment, and a decreasing behavior was observed that suggested that the dissolution of CO₂ into the oil controlled the overall density of the system. Even when the density difference was larger in the second experiment compared with the first, the changes in CT number were still small. The two reasons commented upon earlier for this phenomenon—small pore volume and adsorption of CO₂ on the organic matter—are still valid in this case, and a third reason can be added. Reducing the pressure may have affected the solubilization mechanism negatively, because pressure could be lower than minimum miscibility pressure (MMP) for the second experiment. An analysis of the crude oil is not available, but given a 36°API gravity for the oil, it is very likely that MMP is lower than 3,000 psi for CO₂, and therefore the first experiment was performed under miscible conditions, whereas the second could potentially be under immiscible conditions. In this case, the adsorption of CO₂ on the organic matter will also tend to increase the CT numbers, cancelling out to some extent the decrease caused by the difference in density between CO₂ and crude oil. **JPT**

Mapping CO₂ in Real Time With Downhole Fluid Analysis in the East Irish Sea

This paper describes the first successful attempt on the continental shelf offshore UK to map carbon dioxide (CO₂) in real time while logging during a drilling campaign in the East Irish Sea. Reservoirs in this sea's basin contain varying proportions of CO₂, nitrogen (N₂), and hydrogen sulfide (H₂S), in addition to oil and methane. Two of these wells develop the Rhyl gas field. Downhole-fluid-analysis (DFA) technologies were deployed with a wireline-formation-testing (WFT) tool to measure CO₂ content accurately downhole.

Introduction

The Rhyl field was discovered in 2009 and received development approval in 2012. It is located 11 km north of the North Morecambe field. The North and South Morecambe fields were discovered in the 1970s, with some 7 Tcf of gas initially in place. Production from the Rhyl field extends the longevity of these assets.

Vertical and horizontal variations in CO₂ content in the Rhyl field were assessed across the Triassic Ormskirk sandstone, the upper member of the Sherwood sandstone group. The Ormskirk sandstone formation represents the principal reservoir target in the East Irish Sea, comprising high-porosity aeolian and fluvial sandstones with variable grain size and playa mudstones.

Gas Composition in the Rhyl Field

The composition of the gas found in Rhyl includes both hydrocarbon and nonhydrocarbon components such as N₂ and CO₂. The N₂ is derived from late-stage hydrocarbon generation, while isotope data indicate that the CO₂ has a magmatic origin. It is believed to have been exsolved from the magma of a series of Tertiary dolerite intrusions into the Ormskirk sandstones in close proximity to the Rhyl field. The samples collected during the drillstem test conducted on exploration Well 113/27b-6 provided several qualitative indications of a higher CO₂ content than was originally expected from the correlation with the nearby North Morecambe field: a high gas density measured at the separator and difficulty in sustaining a flare.

Developing High-CO₂ Reservoirs

On average, the global risk of encountering concentrations of CO₂ greater than 1% in a gas accumulation is less than 1 in 10, and the risk of encountering concentrations of CO₂ higher than 20% is less than 1 in 100. A timely identification of CO₂ in a hydrocarbon reservoir is, hence, essential for several reasons. First, when CO₂ is abundant, it is often so abundant that it can kill the prospect economics. Second, CO₂ occurrence in hydrocarbon-bearing formations presents a challenge to the valuation and subsequent prospect development of the hydrocarbon accumulation. Corrosion is a major con-

cern affecting capital and operational expenditures, but CO₂ also denotes an issue for health, safety, and the environment. In this respect, timely identification and quantification of CO₂ are needed to enable reserves and sales-gas (and hence revenue-stream) estimates to be made, schedule and optimize gas processing, and plan for any eventual CO₂-emission taxes and CO₂-storage or -sequestration costs.

The specific challenge of CO₂-mapping in the Rhyl field is related to the structural complexity of the field itself: The presence of faults, low-permeability sandstone beds, and laterally extensive playa-mudstone beds could potentially make the vertical and horizontal distribution and equilibration of CO₂ in the Ormskirk sandstones difficult to predict. Additionally, the highly reactive nature of CO₂ may result in significant concentration changes before reaching an analysis facility. Optimizing the fluid-sample-acquisition program to account for existing fluid complexities is impossible without real-time analysis.

Initial Evaluation

The presence of CO₂ was identified during the post-well analysis of the 113/27b-6 exploration well in 2009. No downhole gas sampling or fluid analysis was planned because the gas composition was expected to be similar to that of the North Morecambe field. During testing, difficulty in lighting the flare and the high gas density measured at the separator both indicated the presence of CO₂. High CO₂ content was confirmed subsequently during pressure/volume/temperature (PVT) analysis of the surface samples, and isotopic analysis confirmed a magmatic origin.

Initial petrophysical analysis of the reservoir interval identified the presence of an upper and lower Ormskirk sandstone unit, with porosities up to 24%

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 166497, "Mapping CO₂ in Real Time in Hydrocarbon Reservoirs With Downhole Fluid Analysis: First Successful Experience in the East Irish Sea, UK Continental Shelf," by B. Quayle, S. James, and M. Quine, Centrica Energy, and I. De Santo, P. Jeffreys, and J.Y. Zuo, Schlumberger, prepared for the 2013 SPE Annual Technical Conference and Exhibition, New Orleans, 30 September–2 October. The paper has not been peer reviewed.

For a limited time, the complete paper is free to SPE members at www.spe.org/jpt.

and permeabilities up to 2 darcies and separated by a laterally continuous mudstone unit (Centurion mudstone) offset by faults. Downhole formation pressures were acquired across the Ormskirk sandstone, suggesting vertical pressure communication across the mudstone.

DFA and Real-Time CO₂ Mapping in Rhyl Field Development Wells. Because of the elevated risk involved with high-CO₂ reservoirs, a key objective of the development plan was to acquire further data on potential variations in CO₂ concentration and on vertical and horizontal distribution of CO₂ throughout the field. Traditionally, the preferred method to evaluate the presence of CO₂ within downhole samples has been through standard PVT analysis. However, because of the nature of this project and its development through an appraisal strategy, information on CO₂ concentration and any potential vertical variation needed to be available in real time, while the WFT tool was still in the hole. This would ensure that a first evaluation of the hydraulic connectivity across the Ormskirk sandstone and Centurion mudstone was possible as soon as the data were acquired, thus maximizing the value of the data acquired by enabling real-time evaluation.

The latest generation of DFA sensors run with the WFT tool was selected as the most appropriate technology to achieve the proposed objectives. This technology combines a series of sensors and allows the application of optical principles for continuous analysis of the fluids passing through the WFT-tool flowline. Two optical spectrometers, combined with fluorescence and composition-independent density sensors, allowed the measurement of gas composition and density with a high level of confidence, thereby assessing any vertical and horizontal fluid variation in real time (Fig. 1). These data were then integrated with pressure measurements obtained on the same wells, and vertical and lateral connectivity and CO₂ variations were then assessed.

With the previous generation of DFA tools, CO₂ has been a difficult component to quantify. This is because water has a broad and strong absorption peak that lies in the same region of the in-

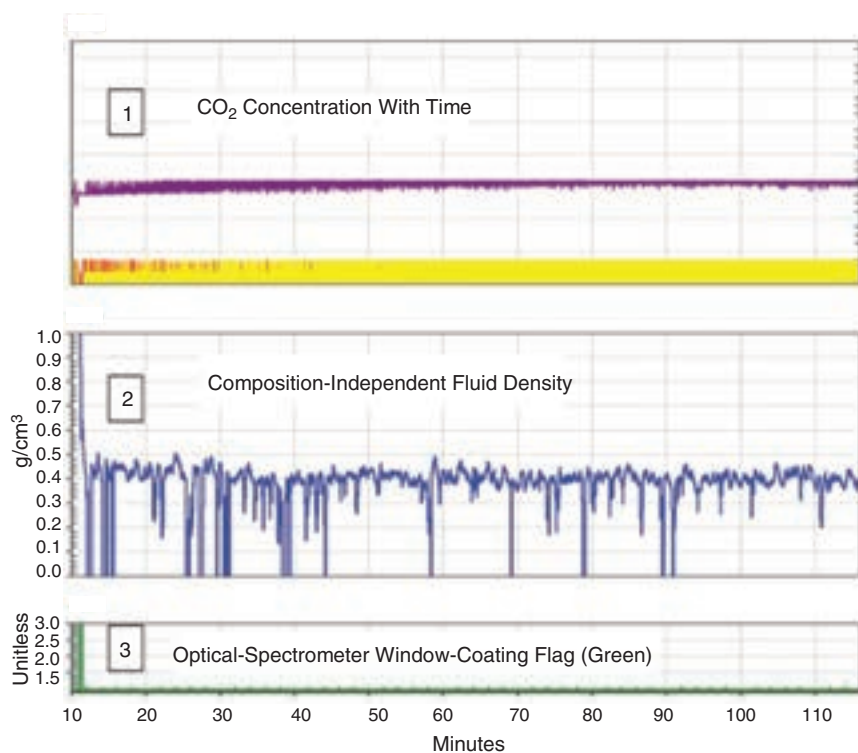


Fig. 1—Real-time fluid composition and density measured by the DFA dual spectrometers deployed with the WFT tool. Note that the Rhyl is predominantly composed of CO₂ and methane, with traces of C⁶⁺, confirmed by the laboratory analysis (Track 1). Real-time fluid density is displayed on Track 2. The bottom track (Track 3) confirms the excellent quality of the signal analyzed by the spectrometers.

frared spectrum as CO₂. The presence of small amounts of either formation water or water-based-mud filtrate can potentially swamp the CO₂ signal. The dual-spectrometer system of this latest generation of DFA tools, however, covers wavelengths from 400 to 2100 nm and uses a number of channels in the near-infrared (NIR) range tuned to the response of CO₂ and to the water vibrational mode, in order to compensate for the effect of water. The quantification of CO₂ in real time is therefore extremely accurate.

Fluid density was measured by a different sensor independently from fluid composition. The ability to measure fluid density independently from composition became key when calculating the concentration of N₂ in the pumped gas. In fact, N₂ has no absorption within the range of wavelength of the DFA dual-spectrometer tool; therefore, its presence cannot be detected or quantified by visible or NIR spectroscopy. A different approach has been used in this case, and the concentration of N₂ has been calculated indirectly.

Estimating N₂ Concentration

An indirect approach for determining N₂ concentration has been used in this project. Initially, the concentration of hydrocarbon and CO₂ was measured by the DFA dual-spectrometer sensor deployed with the WFT tool. The corresponding density for gas of that composition (typically C₁, C₂, and CO₂) was then calculated by solving an equation of state (EOS) at specific pressure and temperature conditions. The measured fluid density was compared with a density calculated by the fluid composition measured by the DFA sensor. The difference between the two densities (the measured and the calculated) was attributed to the presence of nonhydrocarbon components (i.e., N₂). A new fluid composition was then assumed. Density calculation with the EOS was then repeated for this newly assumed fluid, to check the consistency. This process was iterated until the assumed fluid and the EOS came to good agreement. This method of solving the EOS iteratively allowed the building of a reservoir/field-based ternary diagram that could eventually be used to estimate

the concentration of N_2 without solving for the EOS at each sampling station.

Preserving the Original Concentration of CO_2 in the Downhole Samples

CO_2 is a very reactive gas by nature and has the tendency to react with the metals present on the WFT tool (flowlines, sampling bottles, and pumpout units). In order to reduce the scavenging effect of this gas and preserve a representative concentration until the sampling cylinders are delivered to the laboratory for full PVT analysis, a few technical solutions have been adopted.

The WFT-tool string has been configured in reverse-low-shock sampling, a setup ensuring that the length of the path between the probe and the sampling bottles is minimized. This reduces the contact between the CO_2 and the various WFT modules and minimizes any scavenging effect.

The chances of failures in the pumpout unit because of potential embrittlement caused by the CO_2 were minimized by use of CO_2 -resistant displace-

ment units. The sampling cylinders have been coated with a CO_2 -resistant material that ensured that no scavenging effect took place inside the bottles.

Results

More than 170 pressure measurements have been taken within the Ormskirk sandstone formation on four different wells. Analyses of formation pressure and gradients were integrated with DFA performed at 13 different depths. A total of 20 downhole fluid samples were collected from the four wells, allowing an accurate description of the gas and aquifer-water composition.

The use of the latest DFA technologies allowed optimization of the number and location of collected samples. In 30% of the cases, the information coming from the dual spectrometer was sufficient to fully characterize the pumped fluid; thus, no further sampling was required.

DFA did not show any substantial vertical or lateral variation in gas composition, and the analysis of the pressure data and the related gradients confirmed

the vertical and horizontal connectivity of the reservoir. Pressure and fluid data suggest that the presence of the Centurion mudstone in the upper part of the Ormskirk formation does not represent a vertical barrier to gas flow across the reservoir. There are two likely reasons for this. First, the extremely low viscosity of the gas, and thus its high relative permeability, allows the gas to move easily across the reservoir even in the presence of low- or relatively-low-permeability barriers. Second, the Centurion mudstone is known to be fractured to some extent. These fractures represent highly permeable streaks across which the gas could move, allowing the CO_2 to equilibrate.

The gas found in the Rhyl field is mainly composed of C_1 – C_6 and CO_2 , with some minor concentrations of N_2 . The variations between the various wells measured by the DFA sensors are minimal and most likely attributable to measurement accuracy or very localized subtle variations rather than to real compositional differences. No H_2S has been found in this field. **JPT**

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Development of Small-Molecule CO₂ Thickeners

The ideal carbon dioxide (CO₂) thickener would be an affordable, safe, water-insoluble additive that could dissolve in CO₂ at typical wellhead and reservoir conditions during CO₂ enhanced oil recovery (EOR) and elevate the viscosity of CO₂ to the same value as that of the oil. Further, the additive would not require heating or an organic cosolvent to achieve dissolution. In this paper, a strategy for designing a novel small-molecule CO₂ thickener is detailed.

Introduction

Despite its longstanding success as an EOR technique, CO₂ flooding does not recover all of the oil in the formation regardless of whether the reservoir has been waterflooded previously. Typically, primary recovery results in the production of approximately 5–15% of the original oil in place (OOIP), while secondary recovery is responsible for an additional 20–40% of OOIP.

The fundamental causes of this disappointingly low oil recovery can be traced to the density and viscosity of dense CO₂. First, the low density of high-pressure CO₂ relative to oil promotes gravity override of the CO₂, reducing oil recovery in the lower portions of the formation. Second, the viscosity of dense liquid or supercritical CO₂ at typical CO₂-flooding conditions is approximately 0.05–0.10 cp, a value so much lower than typical oil- and brine-viscosity values that it results in an unfavorable mobility ratio. This leads to viscous fin-

gering, which in turn leads to early CO₂ breakthrough, high CO₂-usage ratios, delayed CO₂ production, depressed oil-production rates, and low-percent OOIP recovery. These problems can be worse when the injection well is completed in two or more producing zones.

The density of CO₂ is essentially a function solely of temperature and pressure, and the mitigation of gravity override must be accomplished by mobility or conformance control. It is possible, however, to alter the mobility of dense CO₂ by reducing its relative permeability through water-alternating-gas-injection strategies or by generating CO₂-in-brine foams. It is also possible to favorably alter the distribution of the injected CO₂ in a layered formation, especially if the injected fluids are diverted from high-permeability, watered-out thief zones into lower-permeability, oil-rich zones. Although conformance control is achieved to some extent by each of the mobility-control strategies, there are also techniques designed specifically to block high-permeability zones effectively.

The objective of this paper is to present the initial results of our renewed investigation of another mode of mobility control: CO₂ direct thickeners. The longstanding objective of this research has been the identification of a compound that will readily dissolve in dense CO₂ at typical CO₂ EOR conditions, forming a thermodynamically stable, transparent, single-phase solution capable of flowing through porous media with a viscosity comparable with (or slightly greater than) that of the oil being displaced. The

viscosity of the CO₂-rich fluid could be controlled readily by changing the concentration of the thickener in CO₂.

There are two fundamental strategies for increasing the viscosity of a solution: (a) the dissolution of polymers or associating polymers or (b) the dissolution of small self-assembling compounds that dissolve in the solvent and form viscosity-enhancing supramolecular structures in solution.

There is a long history of attempts to increase the viscosity of CO₂ with either polymers or small molecules, which has been summarized in several recent reviews. A concise summary of these attempts, along with discussions of several new reported attempts, is provided in the complete paper.

Designing a Small-Molecule CO₂ Thickener

Our design principles make use of a relatively inexpensive CO₂-philic segment (an oligomer or low-molecular-weight polymer that readily dissolves in liquid or supercritical CO₂ at conditions commensurate with CO₂ EOR), functionalized with CO₂-phobic self-associating moieties that promote the formation of viscosity-enhancing supramolecular structures in solution.

Examples of CO₂-Philic Materials. Fluorination of the solute typically aids in its CO₂-philicity, but it adds cost and environmental liability. To mitigate this problem, we decided to use alternative CO₂-philic materials. The existence of specific carbonyl oxygen/CO₂ interactions while minimizing solute self-interaction makes these oxygen-containing groups particularly advantageous in CO₂-phile design. In addition to weak solute self-interactions and oxygen/CO₂ interactions, high flexibility/low-softening-temperature compounds have the potential to enhance entropy of

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 169039, "Development of Small-Molecule CO₂ Thickeners for EOR and Fracturing," by J.J. Lee, S. Cummings, A. Dhuwe, R.M. Enick, and E.J. Beckman, University of Pittsburgh, and R. Perry, M. Doherty, and M. O'Brien, General Electric Global Research, prepared for the 2014 SPE Improved Oil Recovery Symposium, Tulsa, 12–16 April. The paper has not been peer reviewed.

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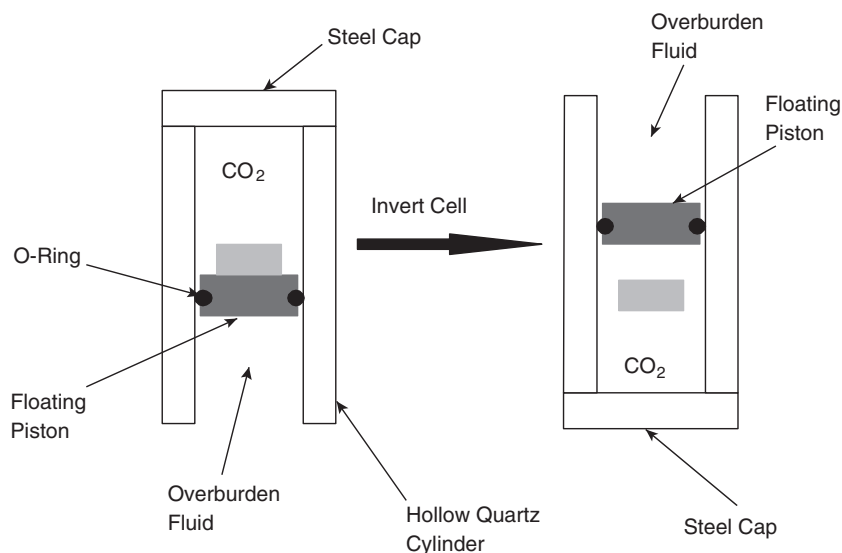


Fig. 1—Falling-cylinder-viscometry apparatus.

mixing of the solute in CO₂. Free volume can also be elevated through branching, methylation, and the use of ether linkages in the backbone. It has been noted previously that most of the CO₂-philes known exhibit relatively weak self-interaction, as evidenced by low cohesive-energy density. Finally, short *n*-alkyl chains are soluble in CO₂ and serve as inexpensive CO₂-philes because of their low self-interaction strength. Therefore, they can dissolve in CO₂, while at higher molecular weights the poor entropy of mixing dominates and the long-chain alkanes do not dissolve in CO₂. Thus, our leading candidates for the CO₂-philic portion of the molecule include oligomers or low-molecular-weight polymers of propylene oxides or dimethyl siloxane, and short alkyl chains.

Examples of CO₂-Phobic Associating Groups. When considering the design of the relatively CO₂-phobic portion of the thickener molecule responsible for viscosity-enhancing intermolecular associations, the key to increasing the viscosity of CO₂ under any conditions is to create the reality or the thermodynamic illusion of a high-molecular-weight solute at sufficient concentration in a one-phase system with use of CO₂ alone as solvent. Given that we have previously ruled out the use of high- and ultrahigh-molecular-weight polymers, we have decided to explore ways in which to create the thermodynamic illusion of high molecular weight in solution through the

creation of associative networks built with small molecules, using noncovalent interactions such as hydrogen bonding. While the creation of noncovalent networks in CO₂ has been explored previously, it is our hypothesis that those previous approaches have failed primarily because the candidate molecules used associating groups with such strong solute/solute interactions between themselves that CO₂ could not dissolve efficacious amounts under traditional CO₂-flooding reservoir conditions. In general, we intend to explore the use of aromatic groups because they are not highly CO₂-phobic and have been shown previously to induce viscosity-changing intermolecular associations.

For a discussion of thickener candidates, please see the complete paper.

Experimental Methods

Solubility Measurement. The solubility of the thickeners in CO₂ was determined by a standard, nonsampling technique. A mixture of CO₂ and thickener of specified overall composition (1 wt% concentration of thickener in CO₂) was introduced to a high-pressure, windowed, variable-volume view cell retained within a constant-temperature air bath. The mixture was retained in the sample volume above a floating piston in the cell and then compressed and stirred (2,500 rev/min, slotted-fin impeller) at an elevated pressure of approximately 10,000 psia (approximately 69 MPa) at the temperature of interest until a

transparent, single-phase solution was attained. The entire sample volume was visible to the observer during this process, and opposing windows allowed the observer to see directly through the sample volume to the light source behind the cell. The mixture was then expanded very slowly by the withdrawal of the overburden fluid situated below the floating piston until a second phase appeared. Typically, a solute-rich cloud point was observed in the form of a fine mist of droplets throughout the sample volume. In order to provide a reproducible and conservative measure of solubility, the cloud point was reported as the pressure at which the suspended droplets prevent one from seeing through the solution, as opposed to the lower pressure at which a greater proportion of the solute comes out of solution and the sample volume becomes completely opaque. After repeating this measurement five times, the temperature of the air bath was raised until the pressure of the solution reached an equilibrium point. The whole procedure was then repeated at the new temperature of interest.

Falling-Cylinder Viscometry. Viscosity data were generated by use of simple falling-cylinder viscometry. An aluminum cylinder was placed within the sample volume of a hollow quartz tube (Fig. 1). Rapid inversion of the high-pressure cell initiated the fall of the cylinder through the single-phase solutions. The cylinder's outer diameter is slightly less than the inner diameter of the quartz tube used, which reduces the terminal velocity of the falling cylinder and minimizes the acceleration length required to reach terminal velocity. Dimensions of the quartz tube under pressure are kept constant because of pressure equilibration across the tube walls.

The aluminum cylinder was placed in the cell before the addition of CO₂ and thickener. The pressure was then elevated above the cloud point, resulting in a single-phase solution. The cell was then inverted and the time required for the cylinder to drop a distance of 5 cm was recorded. Each measurement was repeated 10 times. The cylinder reached its terminal velocity within several millimeters of travel.

The resulting ratio of the terminal velocities of the cylinder in solution to those in neat CO₂ is approximately equal to the ratio of the viscosities under the assumption that the dilute solution is Newtonian and the change in CO₂ density induced by the thickener is small.

Solubility Results

Solubility screening for all compounds was conducted at temperatures of 25, 40, and 60°C. The viscosities of the solutions were evaluated at 1 wt% and 25°C.

In general, all of the aromatic-functionalized molecules were soluble in CO₂ with the exception of A1 (for a table detailing these molecules, please see the complete paper). This insolubility of A1 can be attributed to the high concentration of CO₂-phobic aromatic in the molecule. More than half of A1's chain has pendant propylbenzene groups; these are CO₂-phobic and diminish solubility.

A5, an outstanding water thickener, required relatively high pressures in order to dissolve because the polyethylene glycol (PEG) tails used to enhance

water solubility are only slightly soluble in CO₂. The modified versions, A5 and A6, use higher contents of polypropylene glycol (PPG), which is more CO₂-philic than PEG. Not surprisingly, the cloud-point pressure (a measure of solubility in CO₂) decreases as the PPG content increases. A8 required an elevated softening temperature before any dissolution could be achieved.

The carboxylic-acid-terminated polydimethyl siloxane (PDMS) chains, B1–B6, exhibited very low solubility, if any, in the range of pressures tested. The only acid-functional candidate that showed any promise was B1, which had a much longer CO₂-philic chain compared with the rest of the B group. B1 still required elevated temperatures to achieve solvation, presumably because of hydrogen bonding's temperature-dependent behavior.

Viscosity-Enhancement Results

If the compound was soluble in CO₂, the viscosity of the solution was assessed at a concentration of 1 wt% at 25°C. The pressure was maintained at a value of

approximately 5,000 psi or 1,000 psi above the cloud-point pressure, whichever was greater, and the mixture was stirred at 2,500 rev/min for 15 minutes in order to ensure that a single-phase solution was attained. None of the tested compounds could increase the viscosity under these conditions.

Future Molecular-Design Principles

The structures of these compounds (and others not shown) are being modified continually in an attempt to realize a CO₂ thickener. For example, one can use either low-molecular-weight PPG or PDMS as a CO₂-phile. In either case, the molecular weight can be increased to make the thickener more CO₂-philic if the nature and number of CO₂-phobic groups remain constant. However, if the molecular weight of the PDMS or PPG is increased too much, the thickener will begin to lose CO₂ solubility because of entropic effects of the polymer alone. Therefore, there is expected to be an optimal molecular weight of the CO₂-phile for each thickener. **JPT**

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Society of Petroleum Engineers

Topics for Distinguished Lecturer 2014–15 Season Announced

Featuring speakers from various disciplines and professions, the 2014–15 Distinguished Lecturer Program emphasizes current industry trends, challenges, and technology applications through diverse topics. Subject areas and speakers featured in this year's program are:

Drilling Fluid Influenced Magnetic Shielding of Directional Measurement Tools: Causes and Consequences

The magnetic property of drilling fluid is one of the substantial error sources for the determination of azimuth while drilling deviated wells. These errors, present in all sections, may be in the range of 50 to 200 m when drilling long, deviated intermediate sections. Therefore, these effects represent a significant cost to be mitigated. The error becomes even more pronounced if drilling occurs in Arctic regions close to the magnetic North Pole (or South Pole). The presentation shows how some drilling fluid additives affect the magnetic shielding of the downhole compass. It also shows the origin of most influential types of drilling fluid contaminants, such as swarf and metallic fines, and their effects. Similarly, it is shown that a certain degree of symmetry of the flow paths around the compass is necessary to avoid distortion of the downhole magnetic readings. Finally, guidelines are presented to minimize the negative effects of the magnetic shielding.



Arild Saasen has been a technology adviser at Det norske oljeselskap in Oslo, Norway, since January 2009. He is also an adjunct professor in drilling and well fluids at the department of petroleum engineering at the University of Stavanger. Saasen holds an MS degree from the University of Oslo and a PhD degree from the Technical University of Denmark, Lyngby. In 2012, he was awarded the Carl Clason Nordic rheology prize.

Oilfield Chemicals and Global Issues That Influence Them

Extracting hydrocarbons from subterranean formations is a prolonged operation stretching over several decades. During this period, a bewildering variety of chemical additives

are used to address various needs of the oilwell operations. A 2010 estimate puts the projected global annual oilfield chemicals (OFC) sales at approximately USD 30 billion by 2015. This talk hopes to bring awareness to the status of OFC use from the health, safety, and environmental (HSE) perspective; stimulate a healthy discussion; and put forth a proposal for consideration aimed at unifying global approval requirements for OFC use by all nations based on a cradle-to-grave holistic approach that is based not only on HSE compliance, but also on HSE-based best practices from syntheses all the way through production, storage, and transportation. The talk solicits and urges concept buy-in and a united campaign from global organizations connected to hydrocarbon production to globally harmonize testing protocols and approval processes for OFC chemicals.



B.R. Reddy has been with Halliburton 17 years and is currently chief scientific adviser—chemist. During this period, he has worked in cementing, conformance, drilling fluids, and long-range research covering all areas of Halliburton's chemical research. Reddy's job responsibilities included new product and process developments. Some of the new technologies that he has contributed to were recognized with the granting of 177 US patents. He has coauthored more than 35 SPE papers.

Perforating With Lasers: Are You Ready for the Power of Light?

Lasers are on track to provide safe, nonexplosive, damage-free perforations. Current industrial laser technology addresses efficiency, portability, and reliability issues required for successful commercial field applications on all rock types, including shale. The latest multimode configuration of fiber lasers are now capable of delivering multiple kilowatts of power from an efficient, compact laser source with excellent beam quality, reliability, and long life. They represent an enabling technology

that opens the door for near-term subsurface laser applications under field conditions. Examples of remote surface field applications have been made. The application of high-power lasers for perforating could significantly reduce the primary drawbacks of traditional methods—safety and damage. Lasers can cut through steel, cement, and rock to permit fluid flow with minimal skin damage. Laser perforation concepts were proven under multiple downhole conditions. Many drilling, completion, and subsurface applications with high-power lasers are envisioned.



Brian C. Gahan is founder and president of Laser Rock Technologies, a private energy consulting firm in Cary, Illinois. He was a senior scientist and manager at the Gas Technology Institute. Gahan holds a BS degree in petroleum engineering, a master's degree in chemical engineering, and an MBA degree in finance. He has authored or coauthored more than 40 papers.

Shale Sweet Spot Detection With Surface Seismic

One of the greatest revolutions in the history of the oil and gas industry has taken place over the past decade. This revolution is the rise of the shale reservoirs. Initially, these shales were developed using statistical drilling methods in which a large number of horizontal boreholes are drilled throughout the play. Until recently, gas prices supported the economics of this approach. Because of their success, an abundance of gas has caused a decrease in gas price and a new economic paradigm has emerged: shale sweet spot drilling. Sweet spots result from certain geologic conditions, such as increased matrix porosity or total organic content, increased microfractures, and areas with increased brittleness. These reservoir characteristics affect the physical rock properties that, in turn, affect a passing seismic signal. The ability to locate these sweet spots before drilling significantly affects the economics associated with these plays.



Brian E. Toelle is an adjunct assistant professor at West Virginia University and an adviser in exploration and geophysics at Schlumberger. He holds BS, MS, and PhD degrees in geology and has worked in the oil and gas industry for more than 33 years. Toelle has authored or coauthored 47 professional papers, posters, and presentations and has received Saudi Aramco's Exploration Professional of the Year Award and the Performed by Schlumberger Award.

Lessons Learned in Technology Development and Perforating Smart Wells

Developing new technology is often considered risky, misunderstood, and prone to time and budget overruns. This presentation will use a recent smart well technology development program as an example of challenges in new technology development. It will also discuss challenges of introducing new technology and pitfalls that are often encountered that perpetuate the "not in my well" attitude that is often heard when introducing new technology. Increasing numbers of smart and instrumented wells are being completed worldwide. This presentation identifies challenges and methods developed to mitigate problems associated with and to enable perforating instrumented and smart wells. It will also review the tools and techniques available to perforate these types of completions while avoiding damage to pipe external control lines, cables, gauges, fiber-optic lines, and other critical completion equipment. Discussions will cover a brief history and limitations of currently available tools and techniques.



Curtis G. Blount is a senior fellow adviser at ConocoPhillips in the Houston-based Global Well Technology group, specializing in advancing technology applied in challenging and harsh environments. He has been active in coiled tubing and well intervention research and applied technology development for more than 25 years. Blount has coauthored more than 30 technical papers and holds more than 20 patents.

Fracturing Fluids: How to Frac With Less or No Water

The US Environmental Protection Agency estimates that 140 billion gal of water are needed annually for hydraulic fracturing operations in the United States alone. While that is just a fraction of the total US water usage, the industry is becoming a lightning rod in the water use debate. Add to that the growing concern about burgeoning truck traffic on local roads and the seismic activity often blamed on high-pressure wastewater injection into disposal wells, and you have an environment ripe for regulation proliferation. Additionally, the success of these technologies in North America is raising interest to develop unconventional resources in various parts of the world where freshwater resources are not readily available. The presentation will describe technologies currently available for fracturing applications using lower-quality water, fluid systems that minimize or eliminate water, and systems based on nonaqueous liquids, or even no liquids at all.



D.V. Satya Gupta is business development director of Baker Hughes Pressure Pumping Technology. He has more than 33 years of experience in oilfield chemical product development and applications. Gupta has published more than 60 papers and holds more than 130 international and US patents.

He holds a doctor of science degree in chemical engineering from Washington University in St. Louis.

Unconventional Reservoirs Require Unconventional Analysis Techniques

Rate transient analysis (RTA) has become popular over the past decade as a theoretically robust yet very practical tool for well performance evaluation, making use of continuously measured production rates and flowing pressures, which are collected as part of good production practices. With the advent of unconventional resource plays, these RTA techniques have evolved significantly. In light of these recent developments, it is easy to become lost in the details when trying to analyze unconventional reservoirs, particularly when one considers the complexities of flow behavior, pressure-dependent reservoir properties, high-pressure/high-temperature phase behavior, and the challenges of the well completion geometry. This presentation describes how and why RTA techniques evolved, starting with simple conventional reservoir systems and progressing to the complexity of fractured, ultralow permeability systems. Techniques specific to unconventional reservoirs are presented and the strengths, limitations, and applications are discussed.



David Anderson is a product manager at IHS. He has led the development of IHS/Fekete's F.A.S.T. RTATM software and has become a recognized expert in production analysis. Anderson has authored numerous papers on the subject and has been awarded two Best Presented Paper awards from SPE.

He also received SPE's Outstanding Young Professional Award for Rocky Mountain Region in 2008. He currently serves on SPE's Reservoir Description and Dynamics Advisory Committee.

Offshore CO₂ EOR as Part of a National CCS Program: Opportunities and Challenges

The key message is that the offshore use of CO₂ for enhanced oil recovery (EOR) is in its infancy. But with the adoption of carbon capture and storage (CCS) to decarbonize fossil-fueled power generation, there is a time-critical opportunity to add

value to the CCS chain by adopting and maturing offshore CO₂ EOR. The United Kingdom has a legally binding target to reduce CO₂ emissions by at least 80% by 2050 (compared with those of 1990). To achieve this, a significant proportion of the UK's fossil-fueled power generation is likely to be replaced by new coal and gas-fired power stations equipped with carbon capture. This opportunity is potentially also available to other countries with fossil-fueled power generation and an offshore oil industry. The talk will include policy background, plans by utility companies, sources and sinks for CO₂, the EOR opportunity, infrastructure requirements, logistics, and engineering challenges.



David S. Hughes is a reservoir engineer with 34 years of experience. He works for Senergy in the UK. Throughout his career, he has specialized in the scientific, technical, and engineering aspects of EOR, including hydrocarbon and CO₂ gas injection, chemical and biological processes, and in-situ combustion.

He is undertaking engineering studies related to offshore CO₂ storage, EOR, and low-salinity waterflooding. He holds a BS honors degree in physics from the University of Surrey.

A Holistic Approach to Understanding the Impact and Cause of Fines Production

There is a need to take a closer look at one aspect of sand control commonly recognized but seldom addressed: formation fines. How many times are good sand control methods placed in wells only to have the wells make "sand," which turns out to be fines. Several major operating companies are now starting to notice many wells are showing increasing skins over time. One of the often cited causes is formation fines migrating into and becoming trapped in the near wellbore reservoir matrix or gravel pack or frac pack. What are the sources of the fines? What factors contribute to the generation of the fines? What kind and how much fines are generated? What controls the production of the fines? The presentation discusses a methodical approach to evaluating the potential for fines production, ways to address the issues, and to appraise the effect on the life cycle of the well.



David Underdown is a research consultant at Chevron Energy Technology Company in Houston. He has worked in sand control and formation damage for more than 40 years for Getty Oil Company, Baker Sand Control, and Arco. Underdown has authored multiple papers and holds several patents. He

holds a PhD in physical chemistry.

Geologic Factors Associated With Successful Shale Gas Plays

Shale is the most common sedimentary rock-type in the world, and massive shale deposits can be found on every continent. A lithologic unit is classified as shale if it is composed of fine-grained sediments. To determine if a particular shale is viable as an unconventional hydrocarbon play, various geologic factors must be understood about those sediments. As an example, the shale's mineralogy must have certain characteristics that will allow it to be fractured. The recent shale revolution also required the development of innovative drilling and completion technologies to transform a shale that previously acted as an impermeable seal or barrier for conventional hydrocarbon traps into a producible reservoir. This presentation outlines the key geologic factors required to have a successful shale gas play. It also highlights the fact that all shales are different, and understanding those differences is key to successful shale exploration.



David Waldo is a senior consultant with Gaffney, Cline, and Associates. During the past 7 years, he has been involved in the evaluation of shale plays in Canada, the United States, and southeast Asia. He has more than 30 years of experience in petroleum exploration and development, with a focus on the creation, evaluation, and valuation of international oil and gas opportunities. He is an honors graduate in geology from Texas A&M University.

Acid Stimulation Challenges and Solutions in Deeper Limestone Reservoirs

As oil demand increases and technology advances, deeper carbonate reservoirs are being developed, some offshore in deep water such as in Brazil's pre-salt. These reservoirs contain mainly dolomite/limestone, having porosity variations from microcrystalline to caverns. Depending on the reservoir's tightness and radial damage extent from the construction phase, these reservoirs may require stimulation to initiate production or to be commercial. Carbonate rocks are 100% soluble in hydrochloric acid, which is used to stimulate these wells with positive but seldom optimum results. Limited acid penetration and possible formation collapses at the near wellbore caused by rapid acid reaction can impair the full stimulation benefit. An optimum stimulation can be obtained by balancing penetration and conductivity. More efficient, resistant, and friendly products and systems have been developed. Acid tunneling lateral branches have improved penetration and viscoelastic surfactants have improved acid distribution, both

noticeable in improved treatment results that are illustrated in this presentation.



Gino Di Lullo is a registered engineer and holds a BSEE degree from UCP-Brazil. After training with DS in Bolivia, he worked in field, technical, marketing, and managerial positions for Schlumberger, BJ Services, Baker Hughes, and Superior Energy in the Middle East, South America, Asia, and Africa. He retired in 2013 and became an energy consultant. He holds several patents and has authored more than 50 technical papers.

Pore Scale Imaging in Black Shale: What Does the Organic Matter Look Like, and Does It Matter?

The discovery of nanometer-sized pores in the organic phases in black shale has led laboratories in the oil and gas industry to invest in electron microscopy tools. However, the researchers were confronted with the field of view vs. resolution paradox. Images that show the small pores are typically only a few tens of micrometers wide. The big question is how representative the features are. The latest technology introduced is FIB-SEM, where a focused ion beam (FIB) inside a scanning electron microscope (SEM) enables 3D reconstructions with nanometer resolution. A workflow is presented in which the core plug scale mineral maps are combined with hundreds or thousands of SEM images to define the representative elements of the core plug. Extracting numbers from images is an important part of this workflow. Examples are shown in the Eagle Ford, Marcellus, and Niobrara shales.



Herman Lemmens is a technology manager at FEI in the Netherlands. His role is translating the needs for pore scale imaging in the oil and gas industry into product specifications for new electron microscopy tools. Lemmens' primary areas of interest are imaging of porosity in the organic phases in shale, integrating imaging at different length scales, and relating mineral textures to fracturing efficiency. He holds a PhD degree in physics from the University of Antwerp.

Multiscale Discussions on Gas Storage and Transport in Organic-Rich Shale

It is now well documented that resource shales consist of pores with small volumes contributing to the storage of hydrocarbon fluids. Physical chemistry of fluids under con-

finement in such a small space could lead to various equilibrium thermodynamic states under subsurface conditions; consequently, phases could change and critical properties could shift unpredictably. This presentation will discuss the pressure/volume/temperature behavior of confined hydrocarbon fluids using atomistic modeling and molecular simulations and comparisons with the classical fluid. The behavior is different mainly because of pore-wall-dominated intermolecular forces. The molecular forces also play a significant role on the fluid transport and could lead to potential non-Darcian flow effects during the production. The molecular transport effects on flow will be introduced using mesoscale lattice Boltzmann simulation of gas dynamics in nanocapillaries. The presentation will conclude with a demonstration on the effect of fluid behavior under confinement on shale hydrocarbon in-place calculations.



I. Yucel Akkutlu is an associate professor of petroleum engineering at Texas A&M University. He has been participating in industry-led research on development of new laboratory techniques and protocols in quantifying fluid storage and transport processes in organic-rich shales coupled with geomechanics. Akkutlu's current research is on fluid thermodynamics and capillarity in nanoporous materials. Akkutlu is a chemical engineer and holds a PhD degree in petroleum engineering from the University of Southern California.

Next Generation of Energy-Efficient, Low-Water Usage Heavy Oil Recovery Methods

In-situ heavy oil recovery from oil sand formations has become economically successful in the past 2 decades. Inventions and developments of recovery processes using steam injection such as cyclic steam stimulation and steam-assisted gravity drainage have contributed to this success. However, the major weak points of the steam-based processes are their high energy consumption, large emission of greenhouse gases, and large consumption of fresh water. The compound effects of solvents and heat on the viscosity of heavy oil can provide heavy crude production rates that could be equivalent to or higher than those from the injection of steam alone. Solvent-assisted processes can also contribute to in-situ upgrading. Numerous schemes to use solvent and heat have been invented and patented. However, there is a lack of basic phase behavior data and mechanistic knowledge about the solvent/heat assisted recovery processes. This talk will provide quantitative mechanistic insights into the processes.



Jalal Abedi is a professor of chemical and petroleum engineering at the University of Calgary. He leads a phase equilibrium research facility and a research group that is involved in experimental measurements of heavy oil/solvent/steam phase equilibrium and equation of state modeling and simulation of transport processes. Abedi holds the Natural Sciences and Engineering Research Council of Canada Industrial Research Chair in solvent enhanced recovery processes. He has authored or coauthored more than 100 peer-reviewed papers.

Comparing Formation Evaluation Measurements Made Through Casing With Openhole Logging Measurements

Logging measurements in cased wellbores are almost always more difficult to make and tend to be more sensitive to the logging environment than the equivalent measurements in open hole. While not all openhole measurements are possible in cased wellbores, it is possible to make many of the more basic measurements in either open or cased wellbores. The increasing numbers of horizontal wells, especially in unconventional reservoirs, has led to a trend whereby the majority of new horizontal wells are not logged. Logging while drilling or deployment of wireline tools in long horizontal openhole sections are often not an option because of cost or risk factors associated with deployment. The introduction of pulsed neutron capture measurements nearly 50 years ago provided some of the first opportunities to conduct formation evaluation in cased wellbores. Over the years, new cased hole measurements have been introduced to make measurements previously only observed in open hole.



James Hemingway started at Schlumberger in 1980 and has held various petrophysics and engineering positions since 1982. He moved to Paris in 2001 as a new technology adviser and has been based in Houston since 2010 as a petrophysics adviser focusing on unconventional resources. Hemingway has been heavily involved in reservoir monitoring of enhanced oil recovery operations using techniques designed for use in cased wellbores. He holds degrees in chemistry and chemical engineering.

Diamonds in the Noise—Treasures Lurking in Acoustic Data

Acoustic data are routinely acquired around the world for a variety of uses but most often for classic applications, such as

seismic correlation, pore pressure prediction, porosity, and hydrocarbon identification. However, hidden in the very same waveform data acquired for these purposes is a wealth of additional information. A second look at the data can often yield hidden treasures, such as fracture characterization, permeability, wellbore stability, hole size, cement evaluation, production optimization, brittleness maps, and much more. This presentation will present some of the many gems that can be mined from acoustic waveform data. Included is a brief review of the types of acoustic tools appropriate for each application as well as tips for optimizing data acquisition.



Jennifer Market is the borehole acoustics manager at Senergy, an international software and consulting company. Her role involves acoustic data processing and interpretation, along with development of software and new application. Market also provides industry training seminars to widen the understanding of acoustic data acquisition and applications. She has 15 years of experience in borehole acoustics, working in a service company to develop acoustics tools and applications.

Shale Well Performance Metric: We “Shale” Succeed

This presentation engages several completion and operational issues that affect the long-term performance of horizontal shale wells, in addition to traditional completions. These observations are based on a significant population of wells evaluated for their completion effectiveness, reservoir quality, and other performance metrics. The presentation demonstrates that several common practices may not have the expected outcome unless mitigating measures are employed. It documents the probability that the preventative measures can be beneficial. The fundamental goal and specific point is that relatively minor changes in operating practices have significant long-term benefit and consequences.



James Crafton is the founder of Performance Sciences in Colorado. He holds a master's degree from the University of Oklahoma and a PhD degree in petroleum engineering from the University of Tulsa. Crafton developed the reciprocal productivity index technique, a practical method for the evaluation of producing shale, oil, gas, and coalbed methane wells. Crafton is chair emeritus of the Distinguished Lecturer Committee and was named a Distinguished Member in 2008. He holds several patents.

LNG—Changing Quickly

The liquefied natural gas (LNG) industry continues to diversify. New LNG markets are appearing, and trading patterns continue to evolve. Shale gas has already affected this industry and its full effects have yet to be seen. Floating LNG (FLNG) attracts strong interest. This capital-intensive industry requires long lead times and special contractual relationships between sellers and buyers. The technologies are undergoing change and improvement. The LNG carriers are becoming more numerous and larger. LNG import terminals are appearing in many new countries. Also, previously used commercial arrangements are evolving. Base-load plants are being constructed in new regions, and the traditional LNG supply-demand pattern is becoming increasingly complex. This presentation illustrates some key developments in the world of LNG. Important changes in the trade required investment levels and the technology are described in this rapidly growing and changing business.



John Morgan is an executive of John M. Campbell/PetroSkills. He has published extensively on sour gas treating, LNG training, sulfur recovery, CO₂ EOR and treating, materials of construction, and cryogenic gas processing. Morgan consults for both North American and international clients. He holds a BSc degree in chemical engineering from London University and an ME degree in chemical and petroleum refinery engineering from the Colorado School of Mines. He is a registered professional engineer.

Hydraulic Fracture Complexity: Insights From Geology, Modeling, and Physical Experiments

The shale gas revolution, ushered in through the Barnett Shale development in Texas, demonstrated the potential of multifracture horizontal wells. A close companion with hydraulic fracture placement technology was fracture diagnostic technology. The ideas around hydraulic fracture complexity exploded with the widespread application of microseismic monitoring. This talk will use natural fracture examples and create complex fracture geometries using numerical fracture propagation modeling and scaled laboratory experiments. Evidence of stress shadow effects is illustrated for natural fractures, and the consequent effect in hydraulic fractures is demonstrated through modeling. Cemented natural fractures are proposed as primary pre-existing flaws with which hydraulic fractures might interact, and the factors influencing this interaction are illustrated. Scaled laboratory experiments simulat-

ing hydraulic fracturing in naturally fractured reservoirs illustrate the range of fracture interaction geometries that might occur in the subsurface. Lessons learned from this integrated approach to fracture complexity characterization can help guide well planning, geologic data collection, and hydraulic fracture optimization efforts.



Jon E. Olson is an associate professor in petroleum and geosystems engineering at the University of Texas at Austin. He also serves as sole proprietor of JEO Associates, a petroleum consulting and software company. Olson holds BS degrees in civil engineering and earth sciences from the University of Notre Dame, and a PhD degree in geomechanics from Stanford University. He has published extensively on geomechanics and structural geology.

Shale Plays: How Technology, Governments, Regulators, Academia, and the Public Have Changed the World's Energy Supply and Demand Equation

The global shale revolution is just beginning. Production from US shale reservoirs has increased from 2.5 Bcf/D to more than 25 Bcf/D since 2007, illustrating the viability of this prolific new source of long-term gas supply. Other countries will undoubtedly use the knowledge developed in North America to jump start their own shale plays. Although technical advancements are largely responsible for unlocking the potential of shale gas, the industry's coordination with a broad set of stakeholders arguably have equal, and perhaps more, influence on the implementation of new shale developments. As such, they will increasingly affect our industry's ability to develop these resources. This presentation focuses on key technological advancements that drive shale gas development, but also the important aspect of how the industry is working with governments, regulators, academia, and the public more collaboratively to maximize the immense benefits from this opportunity while fostering the use of best practices.



Joseph H. Frantz Jr. is the vice president of engineering technology at Range Resources. He started working on shale reservoirs in 1984 and has been involved with studies on many shale fields across the United States. Frantz has authored or coauthored more than 40 publications and taught an industry school on developing shale reservoirs. He holds a BS degree in petroleum and natural gas engineering from Pennsylvania State University.

Holistic Diagnostic Approach: The Key to Successful Conformance Engineering

Excessive water production is a widespread problem that can detrimentally affect the profitability of hydrocarbon-producing reservoirs and limit their economic life. A wide variety of mechanical and chemical technologies have been implemented throughout the years for controlling unwanted fluid production, referred to as conformance technologies. The main objective of this presentation is to provide an overview of (1) conformance technology development in recent years, and (2) how proper diagnostics and candidate selection are the keys to high success ratios with these types of treatments. An overview of how water control technologies have evolved in recent years is presented. Several case histories are discussed, highlighting the problem identification stage before execution, including different types of reservoirs, wellbore completions, and water production mechanisms, among others. It is also important to understand that each technology has limitations because conformance treatments are often applied in reservoir/wellbore conditions outside of their operating capabilities.



Julio Vasquez is a petroleum engineer working as a conformance global product champion for Halliburton's production enhancement product service line. He is responsible for providing technical support to the company's global operations related to water and gas shutoff and for the development of strategies for business, research and development, and training activities for conformance. Vasquez holds 10 US patents and has authored more than 50 SPE publications. He holds BS and MS degrees in petroleum engineering from the University of Oklahoma.

Assuring an Adequate Safety Culture in Production Operations

Everyone agrees that it is necessary to have an adequate safety culture to minimize the possibility of major accidents. This presentation explains what is meant by a "safety culture" and provides guidance as to what is required to develop an adequate culture of safety and assure that it exists in practice. A change in safety requires a change in attitudes and actions on the part of both management and worker. Both the operator and the regulator have a role to play in making this happen.



Ken Arnold has almost 50 years of industry experience, with 16 years at Shell and 25 years as founder and CEO of Paragon Engineering Services. In 2007, he formed K Arnold Consulting. In addition he works as a part-time senior technical adviser for WorleyParsons. He is the coauthor of two textbooks and more than 50 technical articles on safety management, project management, and facilities design. He has twice served on the SPE Board of Directors and is currently the vice president of the Academy of Medicine, Engineering and Science of Texas and a member of a National Research Council committee charged with developing a framing report on safety culture in the offshore industry.

Understanding and Checking the Validity of PVT Reports

Information about fluid properties is a required input for every stage in the oil and gas industry, from the reservoir to the refinery. It is, therefore, of utmost importance for reservoir, facility, and corrosion engineers to understand the volumetric behavior and the transport properties of the produced fluid. These fluid properties can be obtained from pressure/volume/temperature (PVT) reports generated either in-house or in external labs. In both cases, engineers should be able to perform a consistency check on the data before including it in their respective tasks. This presentation provides an overview of tools for verifying the consistency of PVT data.



Klaus Potsch is a retired senior expert from OMV and a consultant for fluid studies. For the past 4 years, he has been a guest lecturer in reservoir fluids and their modeling at the Mining University of Leoben, Austria. Potsch holds BS and MS degrees in physics and a PhD degree in mechanical engineering from the Technical University of Vienna.

Formation Damage Matters—Sometimes

This lecture will explain that understanding the effect of formation damage is critical to successful well design. It has long been recognized that formation damage during drilling, completion, production, well intervention, and injection has a serious effect on well performance, field life, and value. This lecture provides some insight into new understanding, modeling, and theories on the effect of formation damage. Specific cases in which damage is not important or is extremely important are explained. The concept of using damage to help with drilling low-pressure reservoirs and the real effect of damage in long wells will be

discussed. The difference between skin factors and formation damage will be explained, and the traditional reliance on skin to help explain and predict well performance will be discussed. The lecture will advocate the use of modern computational power to solve complex physical challenges.



Michael Byrne is the global technical head of formation damage at Senergy in Aberdeen. A graduate of University College Dublin, he has worked in the oil industry for 25 years and has spent 24 years evaluating formation damage and sand control challenges. Byrne has presented training courses and served as a consultant to major oil companies worldwide. More recently, he has pioneered the use of computational fluid dynamics for well inflow modeling and has several patents in application.

Tight Coalbed Methane—A Giant Worldwide Resource: How Do We Produce it? (Challenges and Solutions)

The development of coalbed methane (CBM) has been limited to moderate- to high-permeability reservoirs. However, a significant resource of natural gas exists within low-permeability coals. Worldwide, CBM resources are estimated to range from 3,500 to 7,000 Tcf. As of 2010, however, only 60 to 70 Tcf of CBM reserves were proved. Vast CBM resources are untapped. Because of the coal depositional process and the nature of gas storage and transport mechanisms, a large percentage of CBM exists in low-permeability, or tight, coals. Horizontal drilling and enhanced CBM techniques have been successful in recovering gas from tight coals, but with limited commercial success so far. Better understanding of coal geology and geomechanics will lead to identification of sweet spots that can be successfully developed. Advancements in horizontal drilling technology and potentially enhanced CBM technology will reduce development costs and facilitate commercial development. Research and development is required to advance these technologies.



Michael Zuber is a technical adviser for Schlumberger Asia Area. He is a mentor for the emerging unconventional gas, shale, and CBM business in Asia. From 2003 to 2007, Zuber was vice president of reservoir engineering at CDX Gas. He has authored numerous publications relating to evaluation of CBM reservoirs. Zuber holds a BS degree from Marietta College and an MS degree from Texas A&M University, both in petroleum engineering, and an MBA degree from the University of Pittsburgh.

The Science and Engineering of Internal Corrosion Control in the Upstream Petroleum Industry—Mainly About Managing Water

Unsuccessful control of internal corrosion has historically caused catastrophic incidents in the upstream petroleum industry. Corrosion control requires a synergy between a sound basis of design and an appropriate operability philosophy. Equipment used in upstream operations may include casing, production tubings, risers, flowlines, pipelines, and facilities. Corrosion control-related decisions made at design level and guidelines set for operations will always be driven by water management. Guidelines to control corrosion are strongly based on water quality and movement within the equipment and the process. While corrosion prediction and mitigation involve thorough understanding and application of scientific concepts of water chemistry, flow dynamics, and transport phenomena, corrosion monitoring and inspection requires sound engineering practices to track water, monitor changes, and meet internal and external requirements. The success of corrosion control programs is also strongly affected by the level of collaboration and integration within the asset integrity and operation teams.



Mohsen Achour is leading the corrosion, inspection, and materials group of the Global Production Excellence Division of ConocoPhillips. He holds a PhD degree in chemical engineering and materials from Oklahoma State University and an adjunct professor honorary title from Ohio University Institute of Corrosion and Multiphase Technology Center. Achour has published more than 60 technical papers and holds patents in the areas of transport phenomena and corrosion.

Managed Pressure Drilling: Experiences and Way Forward

Managed pressure drilling (MPD) has been available for more than a decade now. The common thinking is that MPD has the potential to be a widely used enabling technology in the future, but it has been met with relatively limited acceptance by oil companies. One of the key factors to adopting technology is better communication of its benefits using more detailed case studies. The other major factor is that MPD is a complex, multidisciplinary activity that requires specific skills and resources to ensure effective project engineering and management and strict health, safety, and environment management. Confusion about MPD's application may also have con-

tributed to its slow acceptance rate. This presentation will highlight some of the case studies, as well as lessons learned from the MPD implementations. Sharing the true MPD benefit will enhance the adoption of this enabling technology on a wider scale.



Muhammad Muqeem is a drilling engineering specialist at Saudi Aramco. He has more than 20 years of international expertise in underbalanced/managed pressure drilling, wellbore hydraulics, and multiphase fluid flow in porous media. Muqeem has extensive experience in horizontal, multilateral wells including coiled tubing and sour drilling. He has authored and coauthored several SPE papers. He holds a PhD degree in petroleum engineering from the University of Alberta.

Wellbore Position, Quality Control, Gross Errors, and Error Models

Good wellbore positioning, including techniques for avoiding collisions or finding and intersecting other wells, is critical to control catastrophic blowout accidents, rescue stranded miners, drill close-proximity wells with minimal environmental impact, or drill wells with complicated trajectories that access new reservoirs. The trajectory of an oil well is, at best, an estimation of where the well is based on available measurements. Uncertainties on the position of the wellbore increases as points on the wellbore trajectory are farther away from the wellhead. An error model represents the survey tool behavior, modeling errors, and uncertainties of the tools and accounting for measurement procedure. The result is a statistical representation of the uncertainty, with a 3D ellipsoid centered at each survey point of the wellbore trajectory. Quality control of the data to assure the correct measurements is crucial to avoid gross errors. Several examples will be used to illustrate the benefits of directional data quality control.



Nestor Eduardo Ruiz is LAS area manager for Gyrodata. He holds an electronic engineering degree from the University of Buenos Aires in Argentina. Ruiz started his career in 1983 as a field services engineer and then moved into development and producing directional software for planning and controlling wellbore trajectories of directional wells. He planned the trajectories of the first horizontal wells drilled in Argentina, which also included blowout well experience.

A 30-Year Perspective on Use of Dynamic Well Test Analysis

Dynamic well test analysis is a family of techniques that petroleum engineers use to characterize wells and reservoirs. As with any technology, users need to understand why they do it, how it can be improved, and how it fits into the wider perspective. Overall, the possible rationales for testing have not significantly changed over the past 30 years, but the ever-increasing economic pressure for cost efficiency competing with the improved ability to deliver quality interpretations has changed the relative importance of the rationales. Three examples of improved dynamic well testing are optimal value testing, permanent downhole pressure gauges, and the new rate transient concepts being used for unconventional wells. These technologies are safer and cheaper yet deliver better decisions. These case studies on how a major operator used pressure transient analysis during the past 30 years will enable petroleum engineers to make better choices about how they should appraise and survey their own reservoirs.



Robert H. Hite retired as Shell's principal technical expert on well testing in 2008. He consulted for Shell's worldwide operations and was the primary reservoir engineering instructor for well testing. Since 2008, he has continued well test consulting for a wide range of international companies. Hite

holds a bachelor of chemical engineering degree from Georgia Tech and a PhD degree in chemical engineering from Rice University. Over a 32-year career, besides well testing, he worked on a wide variety of reservoir engineering problems including reservoir simulation, steamflooding, and appraising and developing deepwater Gulf of Mexico reservoirs.

Moving the Frontiers in Artificial Lift Technology in Mature Field Operations

Nearly 40% of today's oil production comes from mature fields, and this proportion is increasing. A significant portion of operating costs in brownfields is related to lifting costs and maintenance of artificial lift equipment. Often additional costs for workovers arise because of suboptimal corrosion control, when sand production becomes an issue (unconsolidated reservoirs), or as the result of a long waterflood history. Any combination of these problems can lead to premature abandonment of the

field despite the fact that significant oil and gas reserves remain in the reservoir. To combat this loss of reserves and valuable energy resource, a number of measures must be taken. The presentation will provide a field case showing this process and will give a detailed insight of the basket of technical solutions and the commercial impact.



Siegfried Muessig is a technology and quality manager at RAG, Vienna, Austria. He holds a diploma and a PhD degree in physics from the University of Karlsruhe, Germany. Throughout his career Muessig was dedicated to innovative technologies when conventional solutions failed. He has published 35

technical papers and holds six patents. Muessig is a guest lecturer at the University of Leoben, Austria.

Diamond: A Driller's Best Friend

A 250-year history of scientific development preceded the first synthetic diamond. Finally, in the 1950s, when understanding and equipment aligned, the breakthrough came—man finally made diamond. A period of increasing understanding of the manufacturing process followed, leading to a new product every year for machining of nonferrous materials. Two decades later, in 1973, the polycrystalline diamond compact (PDC) bit was invented, but it took another 7 years of development before it established itself as the new drilling product for oil and gas wells. Early this century, following another 20 years of innovation, peaking with the invention of a thermally stable PDC, the PDC bit market finally exceeded that of the roller-cone bit. A decade has passed since the last great innovation, but exponents of the synthetic diamond art have demonstrated, throughout its history, a thirst to drive the technology forward. How will they combine the latest knowledge and newest equipment?



Terry Matthias holds a BS degree in mechanical engineering, is a chartered engineer, and a Fellow of the Institute of Mechanical Engineering in the United Kingdom. He joined Drilling & Service, a drill bit company, in 1980 at the beginning of the successful commercialization of PDC bits. For the past

33 years, he has worked on PDC bit and cutter design and development. He led the team that invented an industry-changing and award-winning thermally stable PDC.

SPE Realigns Standing Committees

The SPE Board of Directors has approved a realignment of SPE's standing committees to clarify the scope, nature, and reporting relationships of these groups. This realignment also sheds light on possible volunteer opportunities for members who want to get involved in these groups, which are essential to the activities and outreach of SPE.

The Board of Directors took the action at its March meeting at the recommendation of an SPE Board Finance and Strategy Committee task force. "The

realignment of the standing committees follows the change in the board committees last year and helps to better focus activities on the strategic plan," said SPE President Jeff Spath. "This will also give members who want to volunteer a clear understanding of the opportunities, which is vital to SPE."

SPE had 42 standing committees that were responsible for a number of important SPE activities and which reported to the Board of Directors. Because of the growth in the number of these groups and the fact that their charters had not been reviewed in more than a decade, the Finance and Strategy Committee appointed a six-person task force to review the current standing committee structure, including the charge of each committee, its ongoing contribution, reporting relationships, whether some should be merged to gain efficiencies, and the process for sunseting committees.

This Standing Committee Governance Framework Task Force made six proposals to the SPE Board of Directors, all of which were approved. The recommendations were that the Board of Directors should:

- Establish a consistent set of definitions for these collaboration networks: standing committees, technical sections, task forces, work groups, advisory committees, and councils.
- Adopt the following work flow when a recommendation for a new group is made by a board member or officer:
 - Establish a board task force, accountable to the Board Finance and Strategy

Committee, to study the focus area identified or endorsed by the board, and make recommendations for next steps.

- If warranted, establish a standing committee or technical section depending on the task force recommendation.
- Board members and technical sections may consider the need for temporary work groups as appropriate to support work efforts focused on specific issues or challenges.

- Transition the following standing committees to technical sections, with the noted board technical director liaisons: Carbon Capture and Storage Committee (tied to Research and Development Technical Director), and the Research and Development Committee (tied to Technical Director Chairperson)
- Transition the following standing committees to task forces reportable to the Finance and Strategy Committee: Sustainability Committee and Talent Council.
- Integrate the following standing committees with the understanding that charters will be revised accordingly and endorsed by the appropriate Board committee.
 - Integrate the Technical Communities Coordinating Committee and Online

NEW BOARD COMMITTEE TIES

Member Programs

Engineering Professionalism
Education and Accreditation
Young Professionals
Student Development
Soft Skills
Distinguished Lecturer
Membership
Section Activities
Awards Committees [15]

Communications and Knowledge Sharing

Energy Information
Books Development
Editorial Review
JPT Editorial
Oil and Gas Reserves
TCCC/OCAC Integration

Technical Programs and Meetings

Global Training
Annual Technical Conference and Exhibition Program
Forum Series Coordinating

Enhance Your Career. Get Certified.

THE NEW ALIGNMENT

Standing Committee

- ▶ Permanent need for function
- ▶ Defined function remains same year-on-year
- ▶ Multiyear service terms [3-4 years]
- ▶ Supports ongoing program or activity
- ▶ SPE President-elect appoints chairs and members
- ▶ Consists of members at large
- ▶ Can form subcommittees, as necessary
- ▶ Reassess need on 5-year cycle

Technical Section

- ▶ Grouping of members interested in specific technical topic
- ▶ Individuals are free to join [vs. being appointed]
- ▶ Initiated by members, endorsed by Technical Director, and approved by SPE Board
- ▶ Liaise with appropriate Technical Director or Technical Director Chair
- ▶ Reassess need on 5-year cycle

Task Force

- ▶ Initiated by Board officers; approved by Finance and Strategy Committee
- ▶ Fixed scope and time frame
- ▶ Defined deliverables
- ▶ Consists of Board members and invited others

Work Group

- ▶ Initiated by Board member or Board committee
- ▶ Fixed scope and time frame
- ▶ Open to all members and invited others
- ▶ Board approval not required

Advisory Committee

- ▶ Set up to provide advice/input, as needed
- ▶ Established by Board member or Board committee
- ▶ Recommended length of service 3 years

Council

- ▶ National or regional entity
- ▶ Collaboration vehicle for SPE sections

Communities Advisory Committee.

oTransition the 25-Year and Century Club committees to subcommittee status under the existing Membership Standing Committee.

oTransition the US Engineering Registration and Petroleum Engineering Certification committees to subcommittee status under the existing Engineering Professionalism Standing Committee.

oTransition the Forum Series-West and Forum Series-East

committees to subcommittee status under the existing Forum Series Coordinating Committee.

Several items are still under discussion, including a pilot to integrate the Young Professionals Coordinating and Student Development Standing Committees; assessing the charter of the Soft Skills Council; assessing the demographic balance of committee leadership teams, as well as term limits and sunset provisions; and evaluating individual awards by the technical directors. **JPT**

Petroleum Engineering Certification

SPE's Petroleum Engineering Certification program provides you with an opportunity to obtain an international credential recognizing your petroleum engineering knowledge.

Register now for an upcoming certification exam to validate your technical knowledge and skills in engineering fundamentals and problem solving. Or, sign up to take a review course. Find out about upcoming courses and exams in your area at www.spe.org/training/exams.



Society of Petroleum Engineers

SPE Student Chapter Tours Barnett Shale Sites

In April, the University of North Texas SPE Student Chapter (UNT SPE) toured four well sites located in the Justin, Texas, area of the Barnett shale. Tour host was J-W Operating. Three of the sites each operated with a different type of artificial lift system. At the final pad on the tour, students saw a workover rig in action. Michael Warren, SPE, senior operations engineer at J-W Operating, organized the event, with assistance from the company's district engineers Shane Haberman and John Lacik. The tour lasted roughly 4 hours with about 30 minutes at each location. Additional time was spent in the field office, where the host company team showed students plunger lift valves and other equipment.



Pictured (left to right): Erin Wood, UNT SPE treasurer; Ryan Burch, UNT SPE student member; Michael Warren, J-W Operating senior operations engineer; Armstrong Ekpote, UNT SPE student member; Martin Steenbock, UNT SPE student member; and Michael McClain, UNT SPE president.

Improve Your Technical Writing Skills: New SPE Course

“Technical Writing and Publishing: Tools, Philosophies, Strategies, Methods, Pitfalls, and Tricks”—a new SPE course for industry professionals who want better writing and publishing skills, especially for technical papers—will be held 19–20 August at SPE's Houston training center. Kevin Mahrer, chief scientist at geophysical firm Sigma³, will teach. The course covers many topics, including document goals, writing to your audience, and merging your goals with reader needs. The training center is at SPE's Houston office. Registration is available online at www.spe.org/training/courses/TWP.php.

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Leadership Program Targets Young Professionals

SPE is developing a new program called the “SPE Leadership Academy” to instruct young professionals in soft—or nontechnical—skills critical for career advancement. Engineering graduates enter the workforce with strong technical skills, but often lack nontechnical skills vital to success in the oil and gas industry. For many early career professionals, finding the skills that will help transition them from an individual contributor to a leader can be difficult. The program will sharpen communication skills, help participants learn how to handle issues such as dealing effectively with difficult coworkers, teach them how to relate to management, and give them the tools to influence coworkers through means other than formal authority. SPE plans to hold the first sessions of the “SPE Leadership Academy” in Dubai and Houston in September. Announcements about the program will be available on SPE’s website, www.spe.org.

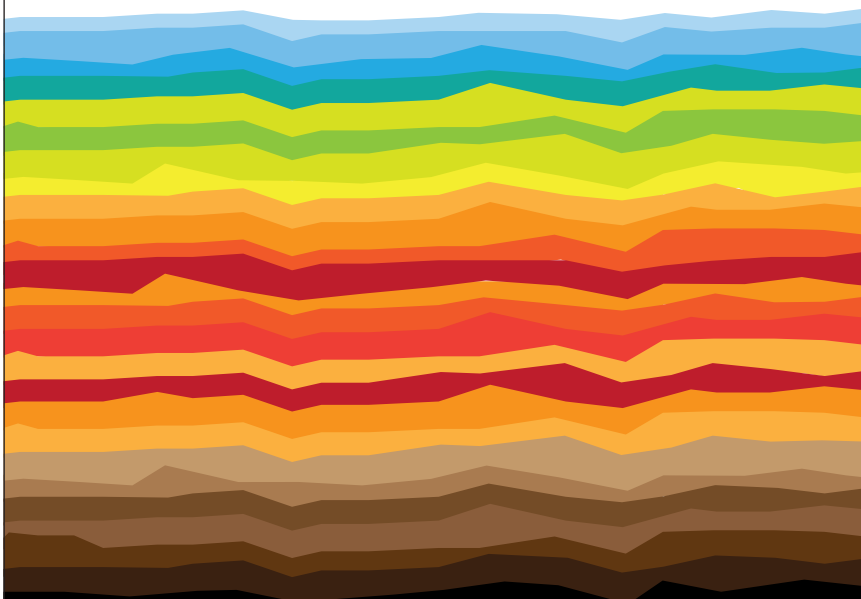
SPE Partners With Offshore Media Group

SPE and the Offshore Media Group (OMG) announced a multiyear, joint partnership to develop a series of SPE technical conferences, workshops, and training courses at Offshore Technology Days (OTD), an annual energy trade show exhibition organized by OMG and held in Norway. OTD2013 attracted 510 exhibitors and around 27,000 visitors. Founded in 1982, OMG is a Norwegian energy communications company. Starting at OTD2014, SPE and OMG will host a series of technical workshops and training courses, designed to foster knowledge transfer and provide a platform for discussion of regional issues. OTD2014 is OTD’s 16th edition, to be held during (14)–15–16 October in Bergen, Norway. In 2016, SPE will launch a biennial technical conference, to be held alongside the OTD exhibition, focusing on technical knowledge, best practices, new technologies, and specific challenges faced by the North Sea offshore E&P industry. For more information, go to www.offshoredays.com. **JPT**



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THOMAS P. BURKE, SPE, was elected chief executive officer (CEO) of the Rowan Companies. He has served as chief operating officer of Rowan since 2011 and was promoted to president in March 2013. Burke joined Rowan in 2009, serving as president and CEO of subsidiary LeTourneau Technologies until 2011, when Rowan sold LeTourneau. At Complete Production Services, he was division president from 2006 to 2009 and vice president of corporate development from 2004 to 2006. Before this, he served in various roles at Schlumberger and McKinsey & Company. Burke holds a PhD in engineering science from Trinity College, Oxford, and an MBA with high distinction from Harvard Business School.



STEPHEN HOLDITCH, SPE, received the 2014 Distinguished Alumni Award from Texas A&M University. Holditch, who served as president of SPE in 2002, is former head of the Harold Vance Department of Petroleum Engineering and former director of the Texas A&M Energy Institute. In 1977, he founded petroleum engineering firm S.A. Holditch and Associates. He has been honored as a member of the Petroleum Engineering Academy of Distinguished Graduates and as an Outstanding Alumnus of the Dwight Look College of Engineering. Holditch was elected to the US National Academy of Engineering in 1995 and has been honored with most of SPE's top technical honors, including Honorary membership and Distinguished

Membership. Holditch earned BS, MS, and PhD degrees in petroleum engineering from Texas A&M.



ROY MARTIN, SPE, has been appointed CEO of READ Cased Hole. With more than 30 years of industry experience, he has held senior management and executive positions both with major service providers and with manufacturing firms in the African, Middle East, and Asia Pacific regions. Martin earned a BS degree in mechanical engineering from Auckland University.



GLENDA SMITH, SPE, has been promoted to vice president, communications at the Society of Petroleum Engineers, based in Richardson, Texas. She will be responsible for the management of SPE technical publications, publishing services, magazines and web content, communications, and energy education. Smith joined SPE in 2002. She developed SPE's web content group, and then moved to technical publications in 2007. Most recently, she held the position of director of innovation, strategy, and analytics. Before coming to SPE, Smith worked for the American Petroleum Institute, ICF Consulting, and *Oil & Gas Journal*. She holds a BS in economics from the University of Tulsa and an MBA from George Mason University.



BRANDON TRIPP, SPE, has been awarded a graduate fellowship from the US Tau Beta Pi engineering honor society. The award includes USD 10,000 for graduate studies at any institution of the fellowship winner's choosing. Tripp graduated from the University of Alabama at Birmingham with a BS in civil engineering. He spent 3 years participating in his school's Tau Beta Pi chapter, serving as chapter president for 2 years. He also participated in his school's National Society of Black Engineers chapter, serving as president and vice president during his 3-year tenure. Tripp completed several co-op and internship programs during his undergraduate years and will be serving in his fifth internship this summer with Aera Energy. At the end of his summer internship, he plans to pursue an MS in petroleum engineering at The University of Texas at Austin.



DATO' WEE YIAOW HIN, SPE, was appointed executive vice president and CEO of upstream business for Petronas, Malaysia's national oil company. Wee Yiaow Hin is a member of Petronas' board of directors, executive committee, and management committee and also sits on the boards of several

In Memoriam



ROBERT A. WATTENBARGER, SPE, died on 9 May 2014. He was 78. An active SPE member for 53 years, he was the recipient of the SPE Reservoir Description and Dynamics Award in 2012 and was inducted into the SPE Legion of Honor in 2000. Wattenbarger started his career in 1959, working with Mobil Oil in Colombia. He went on to work for Oil Recovery Corporation and Sinclair Oil in Tulsa, Oklahoma, then Mobil Research in Dallas, Texas, where he developed the first practical compositional reservoir simulator. In 1969, Wattenbarger joined Scientific Software Corporation as vice president, where he remained for 10 years. In 1979, he started his own consulting firm in Houston, joining Texas A&M University as a faculty member in 1983. He had recently been appointed holder of the John E. and Deborah F. Bethancourt Professorship at Texas A&M. Wattenbarger received a BS in petroleum engineering from the University of Tulsa and a PhD in petroleum engineering from Stanford University.

companies within the Petronas Group. He served as a director of the SPE Northern Asia Pacific Region on the international SPE Board of Directors and is currently a member of the SPE Asia Pacific Board of Directors. Wee Yiau Hin joined Petronas in May 2010 as executive vice president for its exploration and production business. Before that, he worked at Talisman Energy Malaysia, serving as vice president. Previously, Wee Yiau Hin was with Shell as vice president, Malaysia for Shell Upstream International Asia and managing director of Shell Malaysia Exploration and Production Companies. He earned a BS degree in civil engineering from the University of Wales and an MS degree from Imperial College, London.

Member Deaths

M.H. Beaver, Houston, Texas, USA
William R. Brinkoeter, Houston, Texas, USA
David E. Harmon Jr., New Concord, Ohio, USA
Joseph W. Jean Jr., Cape Girardeau, Missouri, USA
Joseph Mustacchia Jr., Houston, Texas, USA
Helmut Niko, St. Graz-Mariatrost, Austria
Arnold Leslie Picard, Wanaka, New Zealand
Espy P. Price Jr., Houston, Texas, USA
Albert Dean Rial, Seneca, Kansas, USA
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Royce D. Walker, Abilene, Texas, USA
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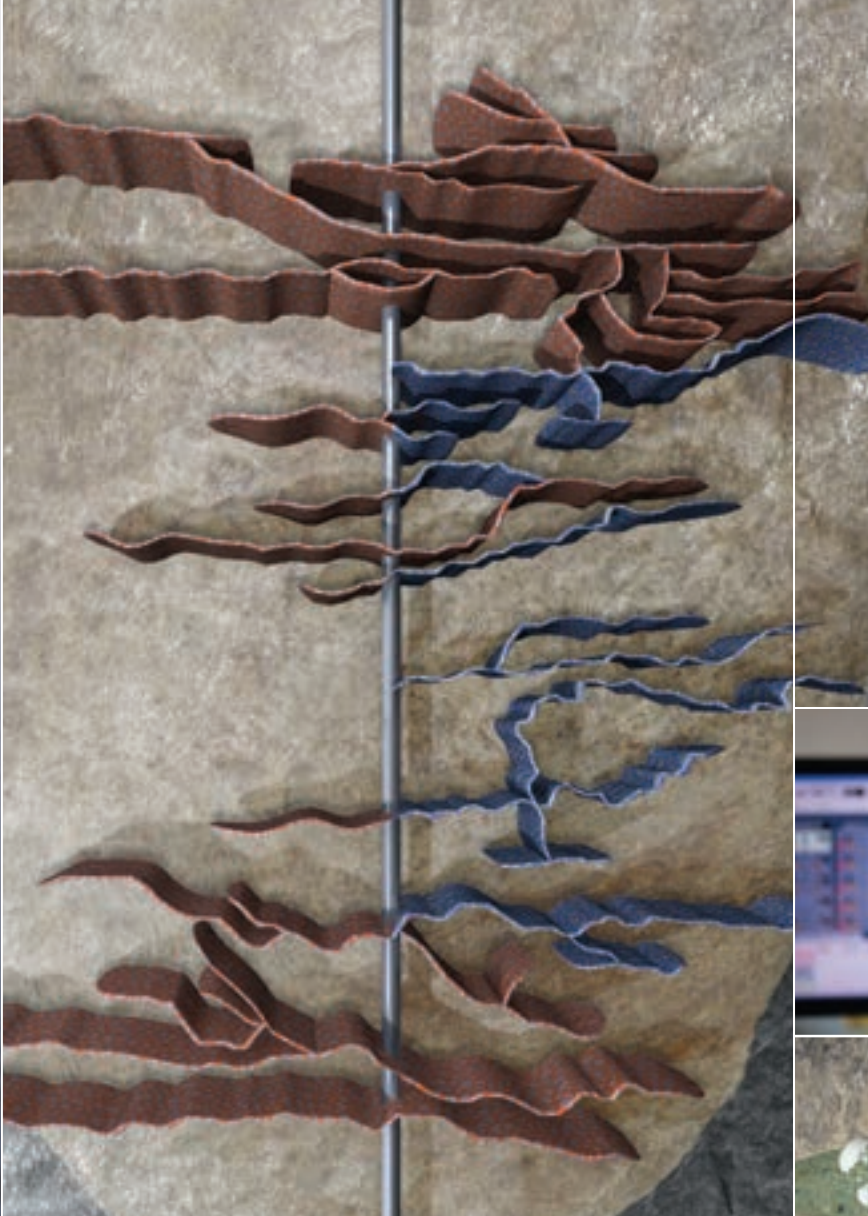
Contact and collaborate with us at PO-Info@weatherford.com



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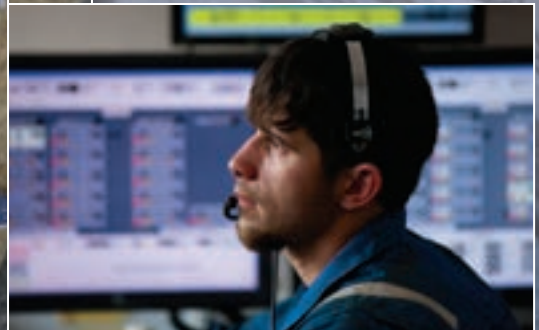
BroadBand Sequence

FRACTURING TECHNIQUE



Conventional stimulation techniques produce highly variable results.

BroadBand Sequence technique stimulates additional clusters (in blue).



An engineered composite fluid of degradable particles and fibers temporarily isolates fractures at the wellbore.

Marathon Oil increases productivity in Eagle Ford Shale well by 21%.

The BroadBand Sequence* fracturing technique effectively stimulated perforation clusters that would not have produced by conventional techniques. Enabled by a proprietary engineered composite fluid of degradable particles and fibers, the BroadBand Sequence technique increased production by 21% over 115 days.

Find out more at
slb.com/BroadBand

Schlumberger