

HP/HT Challenges



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Industry focus on high-pressure/high-temperature (HP/HT) operations seems to go in cycles as exploration successes identify new hydrocarbon resources that can be developed commercially and as technical advances allow wells to be drilled and completed that extend prior capabilities. When production of HP/HT reservoirs becomes dependent upon the development of a particular technology, business incentives create both a substantial momentum and a sharp focus that drives technology development to a successful end.

Historically, this drive has been the case with HP/HT developments. With the passage of time, some may be unfamiliar with the substantial foundation of HP/HT technologies that were created by the hard work of our predecessors. For example, the Association of American Wellhead Equipment Manufacturers (AWHEM) started work on 15,000-psi wellhead equipment in 1952. That research resulted in *AWHEM Standard No. 6* in 1957, which would later become part of the *API 15K* wellhead standards. The first 20,000-psi wellhead system was developed in 1972, which was followed quickly with the development of the first 30,000-psi wellhead system in 1974. These developments were in response to Shell's discovery of the Thomasville field in Mississippi, USA, in 1969. In addition to Thomasville and Piney Woods fields in Mississippi, other substantial HP/HT developments include the Tuscaloosa fields in Louisiana, USA, and the Central Graben fields in the North Sea.

Currently, the industry is pursuing new generations of HP/HT fields including deeper wells in deep water and deep gas wells on the outer continental shelf (OCS). Relative to the deepwater operations, well pressures may approach 15,000 psi at the mudline, and, hence, 20,000-psi subsea equipment is being pursued. Relative to the deep gas wells on the OCS, 20,000-psi surface wellheads and trees, such as those used in Mississippi, Louisiana, and elsewhere, will again be needed, and discussions are active on 25,000-psi equipment.

Just as the industry addressed the new HP/HT requirements successfully and safely that appeared in the 1950s and onward, the industry's current engineering rigor, innovation, and advanced technical capabilities will again converge to address today's HP/HT challenges. These challenges should invigorate our engineers as they lay the foundations and groundwork for the next generation of HP/HT capabilities.

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HP/HT Challenges additional reading available at OnePetro: www.onepetro.org

SPE 123681 • "Elgin/Franklin: What Could We Have Done Differently?" by Eric Festa, *Total E&P* (See JPT, January 2010, page 54)

SPE 118904 • "First Application of High-Density Fracturing Fluid To Stimulate a High-Pressure/High-Temperature Tight Gas Producer Sandstone Formation of Saudi Arabia" by K. Bariko, *Saudi Aramco*, et al.

SPE 124713 • "Depletion-Induced Stress Changes in an HP/HT Reservoir: Calibration and Verification of a Full-Field Geomechanical Model" by M.H.H. Hettema, *StatoilHydro*, et al.

Drilling and Evaluation Technologies Extend Operating Limits in Challenging High-Pressure Deepwater Environments

New drilling opportunities require technological innovations to increase efficiencies and optimize production. Some newer drilling operations, particularly in deep water, involve extreme environments such as ultrahigh pressures that require new approaches. With downhole pressures approaching 30,000 psi and escalating rig costs, rotary-steerable systems (RSSs) and advanced formation-evaluation technologies are needed.

Introduction

Advances in rig design, in downhole tools, in data communications, and in other areas result from challenges associated with pushing and extending limits. While in the planning stages of a deep-water high-pressure well, risk mitigation and contingency planning are critical in making technology advances. It is important to balance the drive to advance technology with the value created.

Solution Potential

In many cases, wellbore construction can be accomplished with standard off-the-shelf products and services. When the location moves into deep water, the complexity, risks, and costs of those operations require fit-for-purpose or application-based solutions.

In this case, early in the design phase of the well, increased potential of a

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 124324, "Drilling and Evaluation Technologies Extend Operating Limits in Challenging High-Pressure Deepwater Environments," by Waitus Denham, SPE, Shell, and Brian Donadieu, SPE, Ernest Lee, SPE, Rohit Mathur, SPE, and Ananth Srinivasan, Baker Hughes, prepared for the 2009 SPE Annual Technical Conference and Exhibition, New Orleans, 4–7 October. The paper has not been peer reviewed.

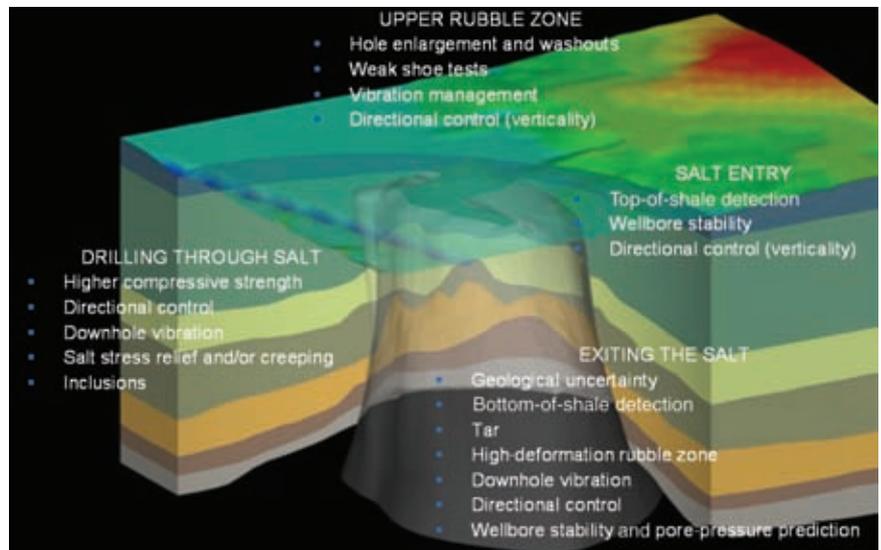


Fig. 1—Typical salt challenges.

high-pressure situation was evident that would require equipment that was unavailable at the time. Therefore, the operator approached a selected vendor and began a feasibility study. Open communication between the companies was critical. After developing an understanding of the operator's critical success factors, the service company gained clearer insight into the challenges at hand and was able to address the effects and risks associated with "new" technology.

Development Stage

Typically, well-construction planning involves a few key individuals from both companies. For this case, it was important to involve additional support and expertise to ensure success. Expanded teams from the operator included the drilling, geology, and petrophysical disciplines, along with asset-management and offshore-operations experts. The vendor expanded its operations, applications-engineering, and technical-support functions to include reliability engineering, prod-

uct development, quality management, repair, and maintenance.

A variety of tools was used to ascertain existing pressure limitations and the ability to upgrade and develop solutions to increase limitations to a 30,000-psi pressure rating. The two main components of the analysis were the finite-element method and pressure testing of components and seals in an autoclave to determine limits and verify design ratings and field suitability. After all engineering analysis was completed and designs were deemed fit-for-purpose and approved by the operator, the engineering team focused on developing parts, delivering specifications to manufacturing, and producing maintenance procedures for the building, qualifying, and deployment of the downhole tools.

Well Challenges

The subject well is in Green Canyon Block 434 in the Gulf of Mexico. It is in deep water and has multiple riserless sections. **Fig. 1** shows typical challenges when drilling through these salt sections.

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

This well penetrates more than 13,000 ft of salt section and has pore-pressure uncertainty subsalt, a rubble and tar zone below the salt, tight-margin drilling, deep directional work, and extremely high downhole pressures. Early in the well-design stage, the vendor was brought into the planning process to assist in developing solutions for the critical success factors that would have to be met before reaching the high-pressure section.

Some initial concerns for the well included how to maintain verticality, predict and manage rate of penetration (ROP) for riserless sections, and eliminate directional issues in the shallow sections to ensure that torque and drag, along with casing wear, would not be an issue later. For the jet-in, drill-ahead, and subsequent two riserless sections, ROP and verticality were the primary concerns.

After setting the 22-in. casing, the riser was run and the well converted to a synthetic-based-mud system. The combination of weight and stiffness helped maintain a vertical hole and allowed setting the 18-in. casing as close to bottom as possible.

The next hole section was drilled with an automated RSS and a concentric reamer for running 16-in. casing. This section was set up to have the 16-in. casing set into the top of the salt zone and to prepare for drilling through the salt zone. The bit, bottomhole assembly (BHA), and reamer combination was set up to drill a controlled ROP because of a cuttings-handling-equipment limiting factor. Salt creep, irregular borehole, and/or doglegs could prevent running a 13⁵/₈-in. string into the hole. The RSS technology provided steering capability, vertical control, and the ability to minimize vibration when entering the salt section.

With the plan in place to set the 13⁵/₈-in. casing within approximately 2,000 ft of the expected salt exit, planning for the unknown became more critical. The 12¹/₄×14 in. section would exit salt and encounter an unpredictable combination of potential obstacles (e.g., high-deformation rubble at the base of salt, pore-pressure regression, and tar). By use of a fit-for-purpose integrated BHA including the RSS and formation-evaluation technology, the pore-pressure uncertainty could be eliminated while drilling. The BHA incorporated formation-pressure-testing capabilities along with the standard gamma ray, resistivity, directional, and annular-pressure measurements coupled with the steering

unit to deliver the desired directional control for kicking off the well. Equivalent-circulating-density (ECD) management became critical and was addressed by controlling the ROP throughout the remainder of the well to minimize cuttings loads and the vibration potential associated with “holding back” on ROP. The intention for this section was to set the 11³/₄-in. liner below salt at the base of the expected pore-pressure-regression zone.

In the 10⁵/₈×12¹/₄-in. section, the downhole-pressure regime was expected to be in excess of 20,000 psi, which required elevated-pressure capabilities in the BHA. This section was expected to be relatively straightforward, and the casing point was selected on the basis of pore pressure, or the observance of pressure regression if it came in late.

To manage the expected reservoir pressure, a 9³/₈-in. liner point was required and planned to be set ahead of the target zones, and an 8¹/₂-in. hole would be drilled to total depth. The BHA for the 8¹/₂-in. section required formation-pressure testing, standard logging-while-drilling tools, and the RSS. All of this equipment was evaluated by risk assessment, and design upgrades were developed to deliver the 30,000-psi requirement projected in the final section.

Results

- Three hole sections were drilled riserless with reamers and split flow.
- The integrated drilling and evaluation BHA delivered shoe-to-shoe performance drilling, with only one hole section requiring more than a single run.
- A vertical hole was maintained through the salt section, and a 13⁵/₈-in. string was set in a tight-tolerance 14³/₄-in. hole.
- Vibration potential was minimized through BHA design, parameter management, and ROP control.
- More than 13,000 ft of salt was drilled.
- The subsalt kickoff started at 26,000 ft true vertical depth with no issues.
- Formation-pressure testing while drilling showed an absence of the pore-pressure regression, which eliminated the need for the 9³/₈-in. liner.
- Tool capabilities were upgraded to 30,000 psi one hole size early, with no effect on rig operations.
- ROP improvements in the 10⁵/₈×12¹/₄-in. section resulted in significant savings.

- Formation-pressure tests were obtained in a high-annular-pressure environment that exceeded 25,000 psi.

- Full directional control was enabled by use of RSS in a 25,000-psi environment.

- The well was drilled to 30,000 ft in 90 days, 27 days ahead of schedule.

Lessons Learned

A critical success factor was minimizing the risks of nonproductive time. Balancing the drilling risks coupled with the geologic uncertainty (i.e., optimizing ROP to minimize vibration, ECD spikes, cuttings handling, and evaluation) was a key consideration. It was important to find an economic “maximum” to achieve drilling goals and to then adhere to it. The involvement culture established by open communications between the operator and vendor was instrumental in designing fit-for-purpose drilling and evaluation solutions that enhanced decision making while drilling and spotlighted downhole conditions.

Annular pressure was only one factor that determined tool limits. Bore pressure played a large role in the “limitation” of tools and pressure capabilities. The drillstring, BHA, bit, and annulus form a series of pressure losses. The bore pressure was higher than the annular pressure by default, and tool components had to meet the additional pressures experienced in the bore of the BHA. Bit-pressure drop, motor differential, and turbine losses must be added to the downhole annular pressure with an allowance for ECD spikes. If nuclear sources are mounted internal to the BHA, they must be evaluated for conservative pressure estimates, including motor stalls and other pressure anomalies, to prevent any collapse issues.

Formation-pressure testing below the salt was a very effective tool in determining the pore-pressure regime, and data were used in real time to make decisions regarding casing points and optimizing hole stability. When casing points were pushed successfully, the potential to drill to total depth with a larger hole size became real.

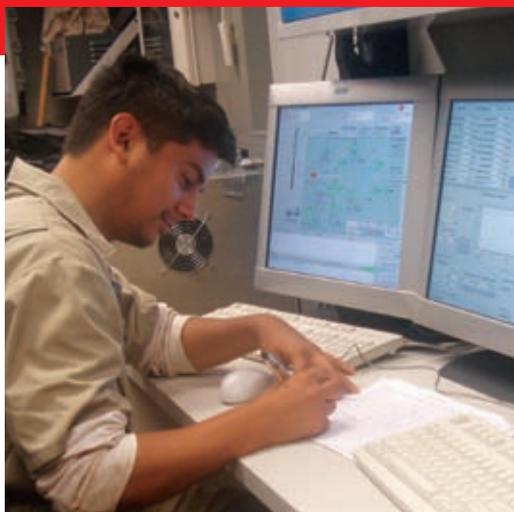
The success case as a contingency must be considered, as well as contingency liners and smaller hole at total depth. Success also can present problems; this well was subsequently sidetracked, and a higher volume of tools was needed than originally planned. **JPT**

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Combining Wireline and LWD Borehole-Seismic Data for Drilling an HP/HT Well

An integrated borehole-seismic technique was used to access and mitigate drilling risk on a high-pressure/high-temperature (HP/HT) exploration well offshore Sabah, Malaysia. The approach combined wireline vertical seismic profiling (VSP) with logging-while-drilling (LWD) seismic surveys to predict pore pressure, determine geostopping, and obtain high-resolution seismic imaging beyond the well path. This high-resolution image was used to select the sidetrack path. The final rig-source VSP was logged at total depth (TD) to complement the pore-pressure prediction and seismic imaging.

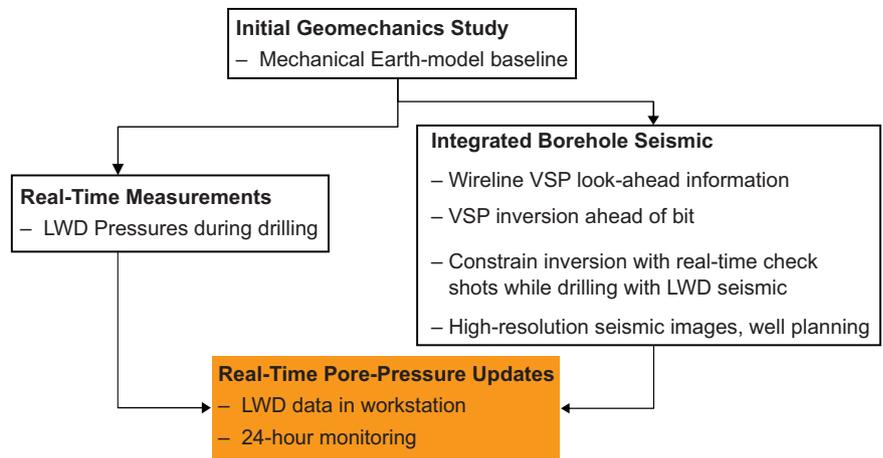


Fig. 1—Workflow for pore-pressure management with integrated borehole-seismic solution.

Introduction

Integrating wireline and LWD borehole-seismic information for drilling is a new technique in Malaysia. In this approach, borehole-seismic data, which are used conventionally for geologic and geophysical interpretation, have added value for drilling and well planning.

The well, drilled in 2008, is off the coast of Sabah, East Malaysia. The target reservoir, in contrast to most other reservoirs in the region, is deeper, hotter, and at much higher pressures

than normal. Pore-pressure ramps and depleted sands in the field had made drilling difficult previously, generating hazardous incidents including stuck and in-hole-lost pipe, fluid losses, and kicks. These incidents had resulted in stopping drilling prematurely, resulting in ultradeep targets remaining unexplored. Studies by the sedimentologist suggested that this overpressure hazard is associated with undercompacted bathyal mudstone, and the well-casing design required accurate prediction.

The well path was designed to avoid the regional fault that could complicate pore-pressure prediction. Existing surface-seismic and distant-well-based velocity control were inadequate for this purpose.

Primary well objectives were the lightly explored, stacked, lowstand Upper Miocene turbidite-reservoir sequences. The deepest of these were expected to be at approximately 4000- to 5000-m sub-sea (SS) depth. The shallow units, which are depleted because of production from other locations, were at approximately 2500- to 4000-m SS depth.

Data Acquisition and Processing

The workflow for this integrated approach for risk mitigation is depicted in Fig. 1. An intensive seismic-logging campaign was conducted on this well, comprising three intermediate wireline-VSP runs, one LWD-seismic acquisition, and one TD wireline-VSP run. The wireline-VSP data were acquired in both openhole and cased-hole sections through the survey by use of four shuttle-imaging tools, each of which had three orthogonally opposed nongimbaled accelerometer sensors. A triple air-gun cluster was used as the seismic source. Real-time monitoring and fast interpretation at the wellsite were performed to ensure high data quality for reliable interpretation.

The LWD-seismic operation was similar to the wireline operation in that it used an active surface source (air guns) and downhole receivers as shown in Fig. 2. The key difference with this service is that the receivers are included in the drilling assembly. Therefore, drilling does not have to be stopped to take measurements, ensuring transparency to drilling operations by acquiring data

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper IPTC 13083, "Combining Wireline and LWD Borehole Seismic Data for Drilling an HP/HT Well: A Novel Approach," by T.K. Lim, SPE, and Aqil Ahmed, SPE, Schlumberger, and Gunawan Taslim and Muhammad Antonia Gibrata, SPE, Petronas, prepared for the 2009 International Petroleum Technology Conference, Doha, Qatar, 7–9 December. The paper has not been peer reviewed.

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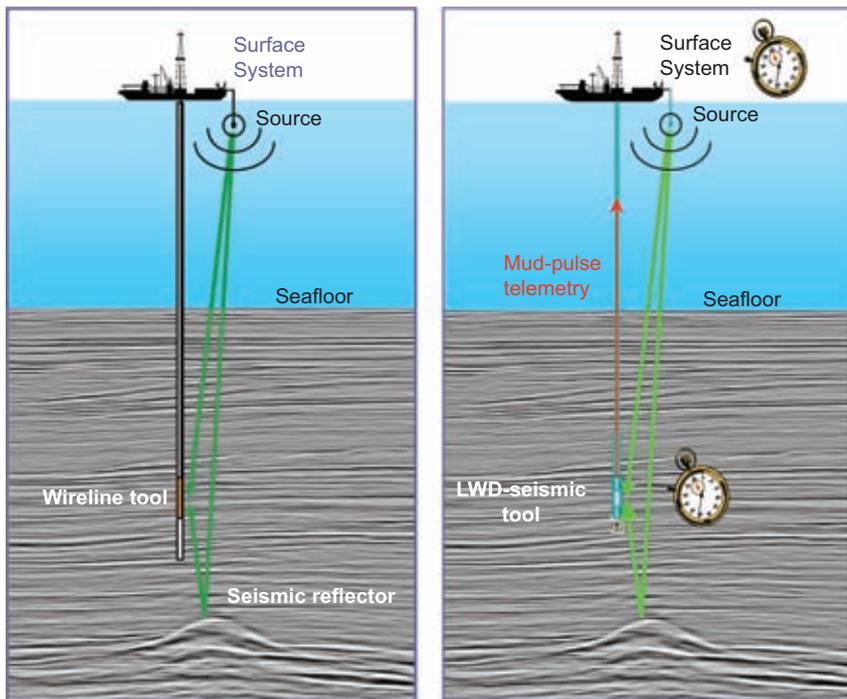


Fig. 2—Simplified vertical-well models for wireline- and LWD-logging methods. LWD seismic is similar to wireline service and uses the same surface source (air guns) coupled with a gun controller. The main difference is no direct cable connection between the tool and surface. Instead, information is transmitted by mud-pulse telemetry.

at connections. Acquiring data in real time mitigates the additional risk of borehole damage and stuck tools associated with running a wireline survey.

True-amplitude processing was carried out to optimize reflectivity information. The final deconvolved wave field provided higher-resolution images for look-ahead information and velocity inversion ahead of bit.

The LWD-seismic tool delivered real-time check shots and interval velocities while drilling, with no effect on drilling time. The real-time time/depth pairs helped to position the bit while drilling and aided in constraining pore pressure ahead of the bit. The processed-waveform results compared favorably with conventional wireline surveys.

Benefits

- Both wireline and LWD vertical-incident VSP showed minor faults that were not apparent on the surface 3D seismic; the presence of the faults explained an unusual kick that was encountered.
- The real-time check-shot-while-drilling survey helped drilling stop within one stand above the key formation top and assisted in coring and casing decisions.
- The real-time check-shot update allowed refinement of the pore-pres-

sure model, enabling critical drilling decisions being made before encountering the high-pressure ramp during the drilling process.

- High-quality seismic imaging along the well plane supported drilling-risk mitigation and well design.
- The technique improved seismic reservoir characterization and reduced structural uncertainty in a challenging environment.

Conclusions

This combined wireline VSP and LWD seismic-vertical-incident VSP yielded high-resolution seismic imaging below the well path enabling drilling-risk mitigation and sidetrack-well planning and providing look-ahead information for pore-pressure prediction. The large amount of borehole-seismic data collected in this campaign provided vital information for seismic imaging around the well path. A crucial subfault system, which was not present on the surface 3D seismic, was revealed by the wireline-VSP runs and the LWD-seismic images. The subfault system also revealed that the supercharging effect was the root cause of the well encountering a kick earlier than predicted with the VSP inversion.

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Accurate Gas-Viscosity Correlation for Use at HP/HT Conditions Ensures Better Reserves Estimation

High-pressure/high-temperature (HP/HT) gas reservoirs have pressures greater than 10,000 psia and temperatures higher than 300°F. Modeling the performance of these reservoirs requires understanding gas behavior at elevated pressure and temperature. Gas viscosity is used to model the gas mobility in the reservoir and can have a significant effect on reserves estimation during field-development planning. Accurate measurements of gas viscosity at HP/HT conditions are extremely difficult. Public-domain databases of hydrocarbon-gas viscosity were reviewed for validity of gas-viscosity correlations and their applicability range.

Introduction

The growing demand for natural gas is driving the search for new deeper sources of gas, many of which encounter HP/HT conditions. Among gas properties, viscosity is seldom measured in the laboratory and, typically, is estimated by use of correlations. At HP/HT conditions, reservoir fluids will be very lean gases, typically methane with some level of impurity, and therefore the gas properties may be different from those of gases at lower pressures and temperatures.

A review of large databases of published viscosity data for pure methane

and mixed hydrocarbons revealed limitations in terms of experimental conditions, data quantity, and in some cases accuracy. The full-length paper details many of these limitations. A review of available gas-viscosity correlations also was performed, which showed that these correlations were developed from experimental data taken at low-to-moderate pressures and temperatures and that their applicability at HP/HT conditions could be limited.

Available Correlations National Institute of Standards and Technology (NIST)

NIST developed computer software to predict thermodynamic and transport properties of hydrocarbon fluids. The software program uses the principle of “extended corresponding states” and was developed from pure-component and mixture data. The maximum pressure and temperature that can be used in the program are 44,100 psia and 1,340°F, respectively. The NIST gas-viscosity values closely match most of the published data, and the predictions generally are reliable for HP/HT conditions in the absence of real HP/HT gas-viscosity measurements.

Lee, Gonzalez, and Eakin (LGE) Correlation

The LGE correlation is based on measured data of pure-component gases and eight natural gases with specific gravities less than 0.77. The correlation can be used to estimate gas viscosity, provided that the molecular weight and density at the relevant conditions are known.

The LGE correlation can be used to predict gas viscosities at temperatures from 100 to 340°F and pressures from 100 to 8,000 psia. Although this correlation does not take into account natural gases containing high quantities of nonhydrocarbon components,

it is considered reliable for predicting the viscosity of natural gases below HP/HT conditions.

Viswanathan Correlation. This correlation is a modified LGE correlation based on NIST values of viscosity of pure methane at pressures from 5,000 to 30,000 psia and temperatures from 100 to 400°F. However, these results cannot be extrapolated directly to situations in which impurities exist in the gas. The Viswanathan correlation can be used with confidence whenever the NIST values are assumed to be valid. For HP/HT conditions, the validity of both NIST values and the modified LGE correlation must be proved against actual measurements.

Gas Viscosities Measured at HP/HT Conditions

A project to characterize the viscosity of gas at HP/HT conditions was initiated. Two types of gases were used: nitrogen as a calibration fluid and pure methane. The investigation was performed with a device that works on the basis of the falling-body principle.

All performed tests were compared with the reported NIST values. At high pressure, all measured viscosities were lower than the NIST values, although in the moderate range (3,000 to 8,000 psia), values match exactly. These results were expected because the NIST values were calculated from existing databases with very few points above 15,000 psia.

Fig. 1 compares measured data from this project with NIST values and other existing databases for nitrogen at 134°F. Test 1 was run from low to high pressure, while Test 2 was run from high to low pressure. Between 3,000 and 8,000 psia, a good match exists between measurement and NIST values. At higher pressure, the measured viscosities were less than those provided by NIST,

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 124734, “More-Accurate Gas-Viscosity Correlation for Use at HP/HT Conditions Ensures Better Reserves Estimation,” by Ehsan Davani, SPE, Kegang Ling, Catalin Teodoriu, SPE, William D. McCain Jr., SPE, and Gioia Falcone, SPE, Texas A&M University, prepared for the 2009 SPE Annual Technical Conference and Exhibition, New Orleans, 4–7 October. The paper has not been peer reviewed.

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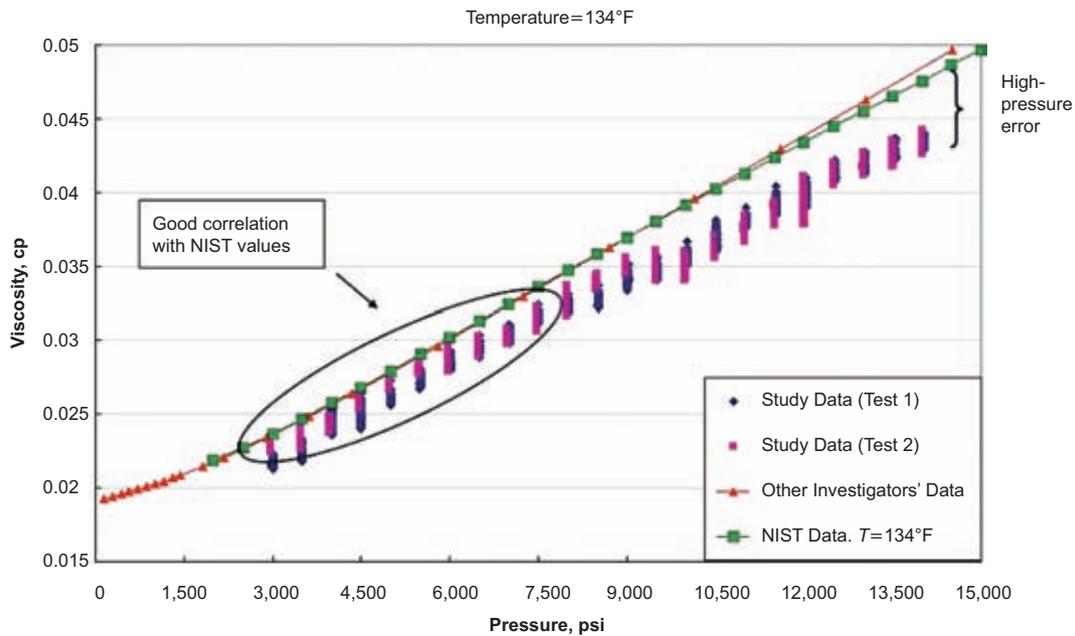


Fig. 1—At pressures between 3,000 and 8,000 psia, there is a good match between study measurements and the NIST values. However, at higher pressure, study data fall below the NIST values.

although they show a similar trend. The same behavior was observed for more than 100 tests conducted at the time this paper was written.

On the basis of these measurements, it can be inferred that the maximum error against the NIST values is -7.48% at pressures greater than 20,000 psia.

At increased temperature, the difference between project data and the NIST values decreased.

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The effect of gas-viscosity uncertainty on cumulative field production was investigated by use of numerical reservoir simulations performed for a simple synthetic case consisting of one well in a pure-methane-gas reservoir having homogeneous rock and fluid properties. Viscosity was defined as an input function of pressure and temperature. The input values were set equal to the NIST values and then perturbed by $\pm 1\%$ to $\pm 10\%$. The aim was to investigate how the difference between NIST values and measurements at HP/HT conditions could affect reserves estimates. The simulator performs an interpolation of the discretized input viscosity values to obtain a continuous viscosity function of pressure and temperature. The uncertainty associated with this interpolation process can be minimized by providing a sufficiently large number of input values, as was the case for this study.

The software package uses an implicit-calculation procedure and black-oil modeling of the fluid properties. No

water flow was simulated, and the runs were performed assuming isothermal conditions.

A small difference in gas viscosity between NIST values and actual measurements influenced estimates of cumulative gas production from the simple HP/HT gas reservoir. An interesting result was that underestimating the gas viscosity yielded slightly worse results than overestimating the gas viscosity.

A -10% error in gas viscosity produced an 8.22% error in cumulative production. A $+10\%$ error in gas viscosity yielded a 5.5% error in cumulative production. These preliminary results suggest that an inaccurate estimation of gas properties may have a significant effect on the predicted reservoir performance of an HP/HT gas field.

Conclusions

Accurate measurements of natural-gas viscosity under HP/HT conditions are yet to be obtained. Gas-viscosity correlations derived from data obtained at low-to-moderate pressures and tem-

peratures cannot be extrapolated confidently to HP/HT conditions.

Gas-viscosity correlations that are available to the petroleum industry were derived from data obtained with gases having limited impurities. Therefore, their accuracy for use with gases containing large quantities of impurities is unknown.

The laboratory investigations with nitrogen showed a consistently negative error compared with the reported NIST values, with a maximum error of -7.48% at 134°F . On the basis of the results from a synthetic HP/HT gas-reservoir model, a -10% error in gas viscosity would produce an 8.22% error in cumulative production, and a $+10\%$ error in gas viscosity would lead to a 5.5% error in cumulative production. These preliminary results stress the importance of obtaining an exhaustive range of measurements of the viscosity of natural gases under HP/HT conditions to ensure better reserves estimation. To this aim, further tests are ongoing. **JPT**

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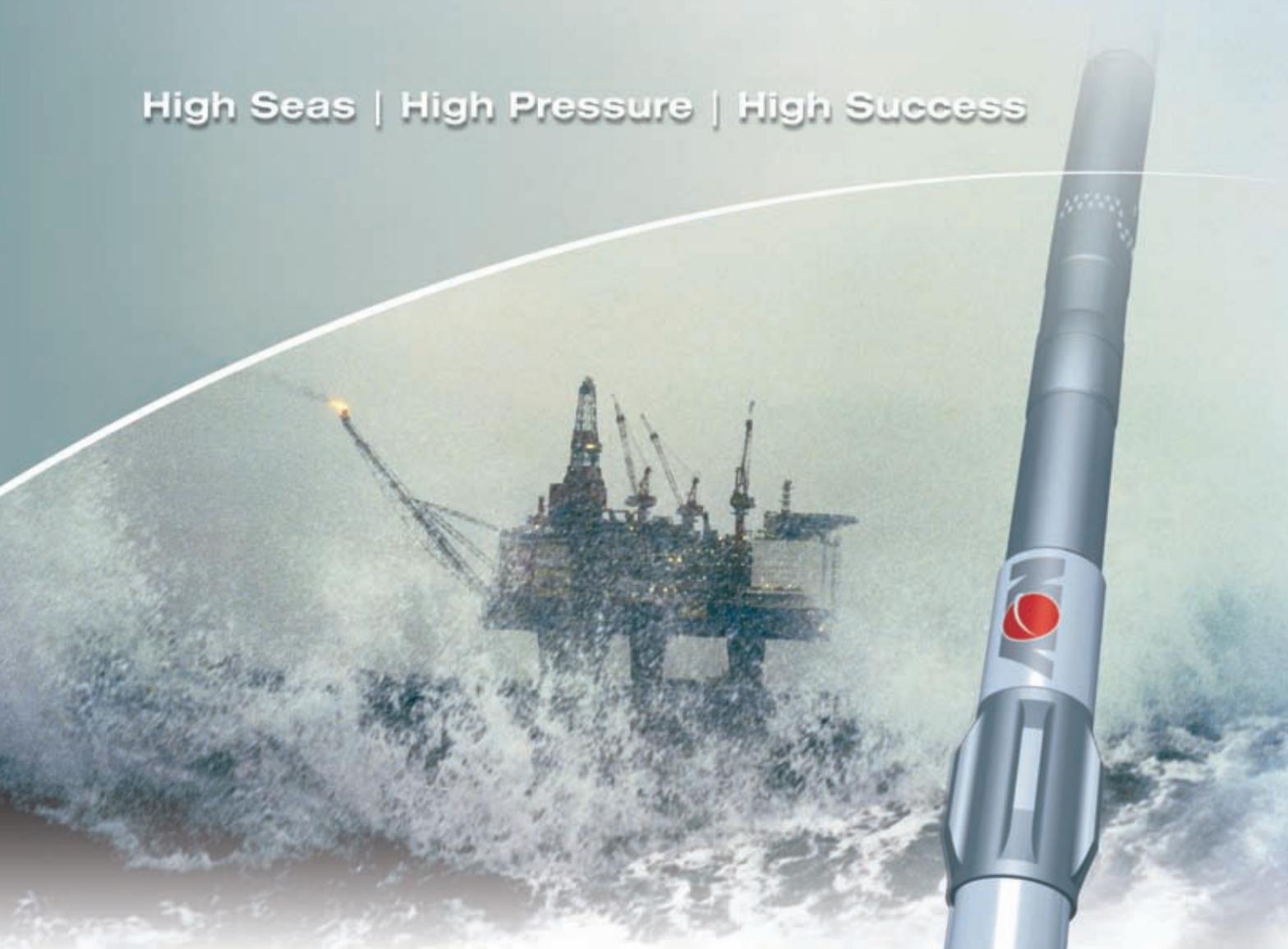
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