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TECHNOLOGY DEVELOPMENTS IN NATURAL GAS EXPLORATION, PRODUCTION AND PROCESSING

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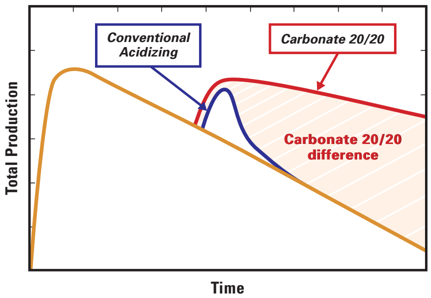

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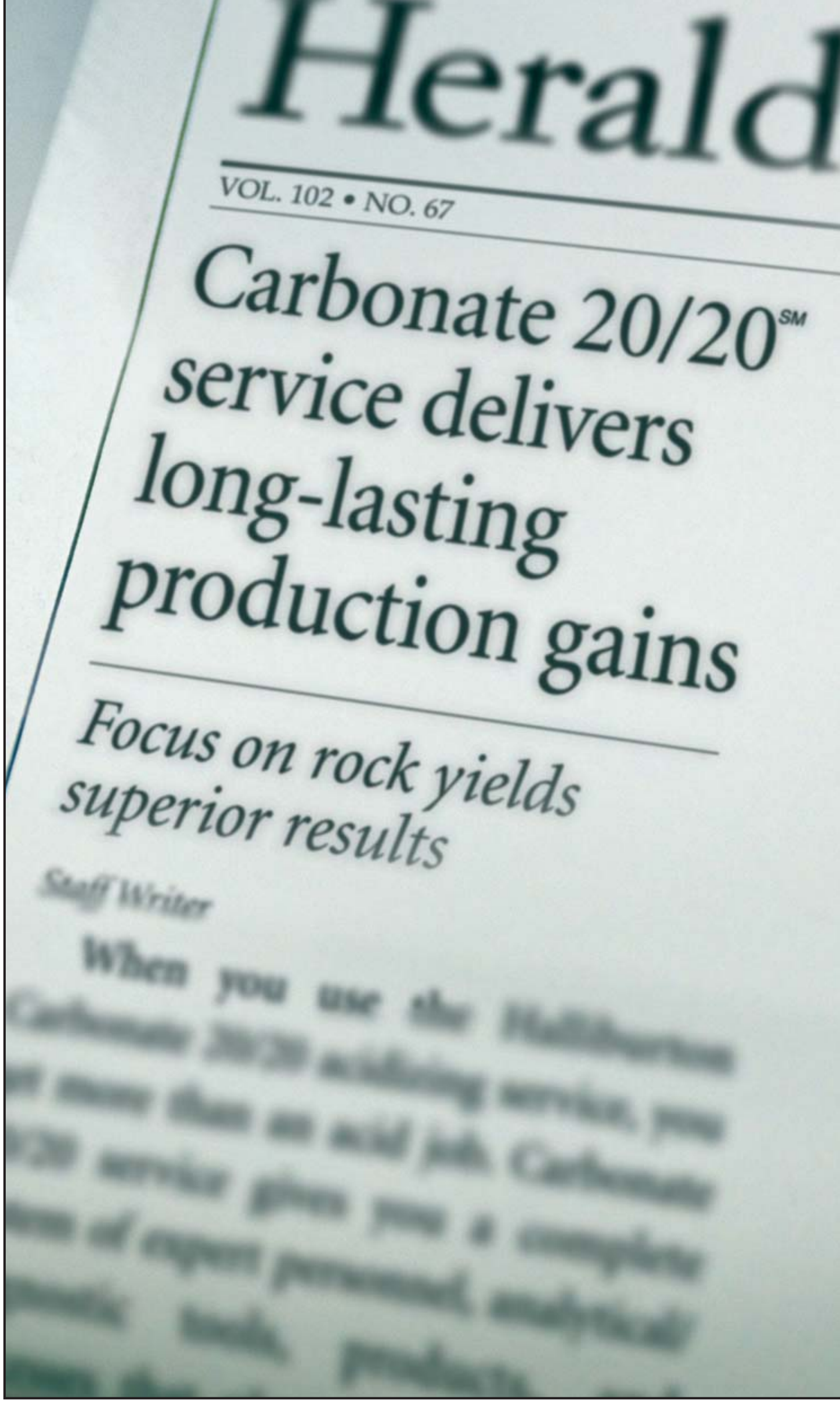

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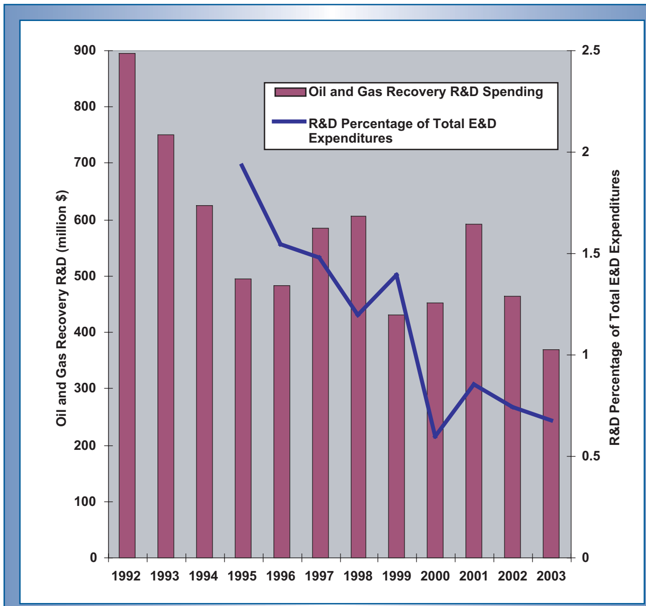
Commentary

Industry R&D Spending in the Spotlight



Oil and gas research and development investment by major exploration and production companies. (Energy Information Administration, 2005)

The issue of oil and gas industry research and development (R&D) is a focus of attention on multiple fronts this summer.

A Society of Petroleum Engineers (SPE) forum held in Colorado from June 20-24 that brought together technologists representing operators, service companies, academia and the government with the objective of stimulating interaction and leveraging each other's efforts related to exploration and production R&D. This forum is one of a number of efforts undertaken by the SPE R&D Advisory Committee, created in 2002 to foster the continuing development of petroleum engineering technology through collaborations of academia, industry and government worldwide. In October, at SPE's Annual Technical Conference and Exhibition in Dallas, an R&D panel discussion will focus on the perception of a decline in operating company upstream R&D, including a reduction in direct research and reduced participation in collaborative efforts. The committee also has sponsored a series of eight articles in the Journal of Petroleum Technology (JPT) that focus on R&D in each of SPE's technical disciplines.

The backdrop to these activities is the picture painted by the 2005 update of the Energy Information Administration report Performance Profiles of Major Energy Producers. This report shows that 2003 expenditures on upstream R&D reported by 28 major U.S. energy companies continue to follow the downward trend exhibited during the past decade (see chart). Service company R&D has filled in a portion of the gap between today's level of upstream R&D investment and that of a decade ago. On the positive side, combined R&D spending by three of the largest exploration and production (E&P) service companies (Schlumberger, Halliburton and Baker Hughes), as reported in their annual reports, has grown by 25% during the past 5 years, but this has not filled in the gap. While the reporting rules for these statistics prevent a precise quantification of exactly how much money is spent on R&D, vs. engineering related to developed technologies, it is clear that total R&D spending focused on oil and gas E&P remains well below historical levels for the industry.

Some believe we may already be seeing the effects of decreased investment. In an article in the June 2005 issue of the JPT titled "Technology's Value in the Upstream Oil and Gas Industry," Ali Daneshy of the University of Houston and Tom Bates of Lime Rock Partners suggest a gradual increase in finding and development costs since 1995 reflects the technology status of the industry for the prior decade. Their fear is that the trend may indicate dramatically increasing costs for the next decade, reflecting an increased aversion to risk by the industry, slower development of technology or both.

Another area of possible concern for the domestic industry in the United States is that what R&D the service companies are doing is pointed toward offshore and other high potential areas rather than toward unconventional resources. This is left to the independents who produce most of the oil and gas and drill most of the wells in the United State but do not individually own enough of the resource to justify large R&D investments.

Don Green, professor of chemical and petroleum engineering at the University of Kansas and one of the chairs of the recent SPE forum, said people are paying increased attention to this trend.

"There is concern about both the decreasing levels of E&P R&D spending on the part of industry and the government, and on the limited degree of interaction between industry and the academic community," Green said. "The industry representatives at the forum support more of both."

One topic the forum attendees discussed at length was how to better inform university faculty on the fundamental E&P problems still in need of solutions. These and other ideas developed from the forum will help form the basis for the October panel.

This issue of GasTIPS includes a range of research topics from geophysical characterization of fractured reservoirs to novel drilling and completion technologies, to high altitude detection of gas pipeline leaks. The array of issues reflects the range of challenges facing the industry. We hope you find this issue of GasTIPS informative. ⌘

The Editors

Imaging Deep Gas Prospects with Multi-component Seismic Data

By Bob A. Hardage,
Bureau of Economic Geology

Gas producers across the Gulf of Mexico are targeting deeper and deeper drilling objectives. Most operators in the Gulf consider 30,000ft to be the deepest target depth that will be drilled for the next few years. To image geology at those depths, seismic reflection data must be acquired with offsets of at least 30,000ft.

Long-offset seismic surveys are difficult to achieve using towed-cable seismic technology in areas congested with production facilities, typical for many shallow-water blocks across the northern Gulf Shelf. Ocean-bottom-cable (OBC) and ocean-bottom-sensor (OBS) technologies are logical options for long-offset data acquisition in such congested production areas because ocean-floor sensors are immobile once deployed and can be positioned close to platforms, well heads or other obstructions that interfere with towed-cable operations. An example illustrating the deployment of ocean-floor sensors across an area of numerous production platforms and facilities in one study area of offshore Louisiana is illustrated in Figure 1. A 6-mile (10-km) diameter circle is positioned on this map to illustrate the difficulty of towing a 6-mile cable across the area in any azimuth direction. In contrast to the difficulty of executing towed-cable operations, OBC lines AA, BB and CC (actual profiles used in one long-offset OBC data-acquisition program) pass within a few meters of several production platforms.

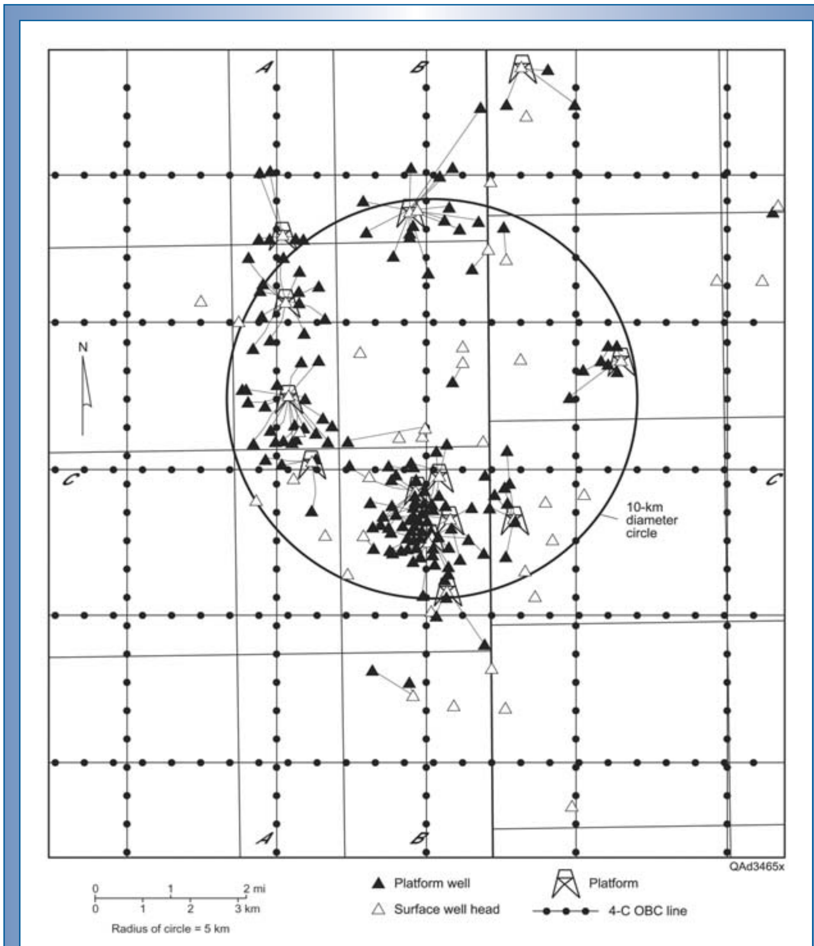


Figure 1. Four-C ocean-bottom cable data acquisition of long-offset seismic profiles across a congested production area.

An additional appeal of OBC seismic technology is that 4-C seismic data can be acquired, allowing targeted reservoir intervals to be imaged with P-SV wavefields, as well as with P-P wavefields. Once 4-C seafloor receivers are deployed, source boats towing only air gun arrays can maneuver along a receiver line to generate P-P and P-SV data from long-offset distances. For the multi-component data used in this study, some field records were acquired with offsets greater than 6 miles. However, data offsets were limited to this distance during data processing.

A P-P image across one study area of offshore Louisiana is shown in Figure 2. This north-south profile is 45 miles (72 km) long, and a scale bar is positioned on the image to represent the dimension of the longest source-receiver offset used in processing the data. This maximum-offset bar can be compared with the physical sizes of the salt structures and rotated fault blocks along the profile to identify where the seismic propagation velocity can be expected to change over lateral distances similar to the maximum offset and possibly affect deep imaging.

Two horizons were interpreted along the profile and neither is a structural horizon. Each is only a marker that indicates seismic reflection quality. Horizon 1, the shallower of the two, marks the base of continuous reflections. That horizon crosses geologic time lines and does not map structure or indicate depth variations of a fixed formation. Horizon 2, the deeper of the two, defines the base of discontinuous but mappable reflections. It also crosses geologic time lines and does not follow a fixed geologic structure.

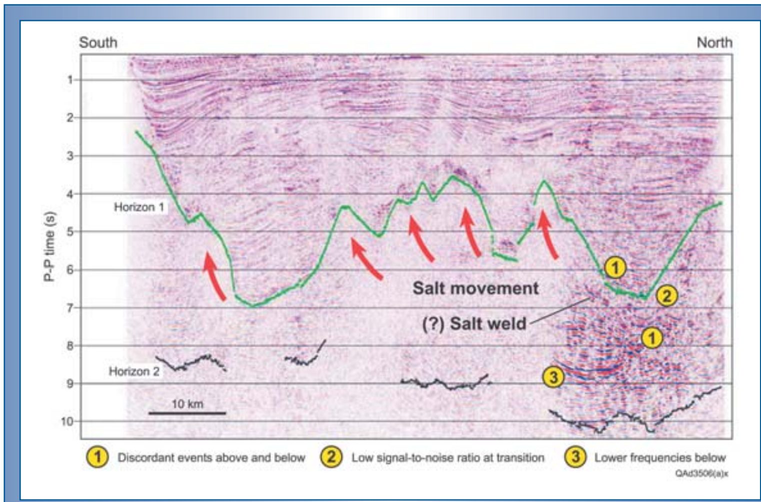


Figure 2. Long-offset P-P image across study area. Horizons 1 and 2 are data-quality horizons defined in the text.

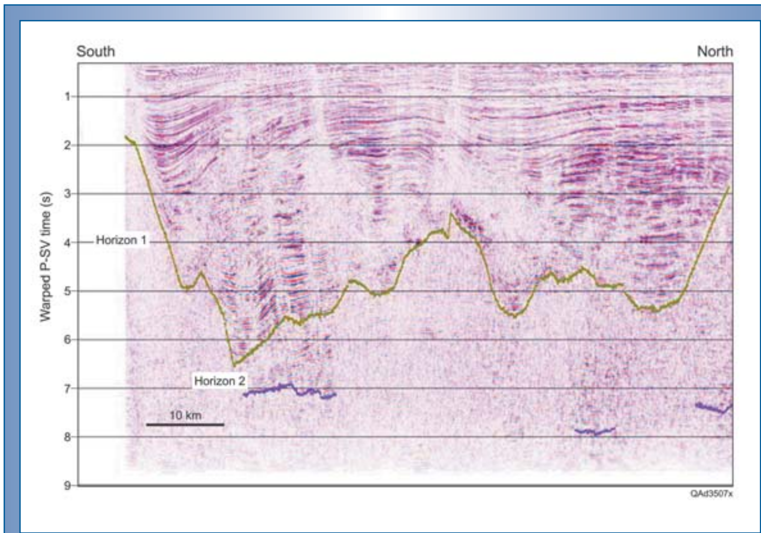


Figure 3. Long-offset P-SV image across study area. This image should be compared with the P-P image of Figure 2 acquired along the same profile.

The profile shows there is a large sediment accumulation in the northern one-third of the image space where Horizon 2 drops down to about 10 s. This sediment load squeezes the Jurassic salt southward, causing several salt structures to punch upward through overlying, younger strata shown by the salt-flow arrows. This salt movement creates numerous echelon rotated fault blocks. The depth of shallower Horizon 1 is controlled to a great extent by the vertical depth to the tops of the various salt structures along the profile. The definition of the base of continuous reflections (Horizon 1) in the north portion of the profile is subjective. Horizon 1 could be positioned at the north end of the seismic line deeper than where it is shown in Figure 2. The exact vertical position of Horizon 1 in P-P image space is not too critical because the surface is used as a data-quality indicator, not as a geologic horizon.

The 10-s image times of the deepest P-P reflections on this profile are considerably deeper than the maximum P-P seismic image times observed with "conventional" seismic data in the area. Interpreters who have examined these long-offset data acknowledge that the data image deeper geology than do shorter-offset seismic reflection data acquired to date over the northern Gulf Shelf.

In the north portion of this profile, a salt weld is near Horizon 1, where underlying salt has evacuated and flowed south. The classical P-P seismic attributes of a salt weld are labeled on the data display:

- events above the weld are usually discordant with events it;
- the signal-to-noise ratio is often low in the data window that encompasses the weld; and
- events below the weld tend to be lower frequency than those above it.

The P-SV image along this same profile is displayed as Figure 3. The vertical axis labeled "warped P-SV time" means P-SV image time has been adjusted to P-P equivalent image time, at least to a first-order level of accuracy. If the P-SV image in Figure 3 is compared with its companion P-P image (Figure 2), P-SV Horizon 1 is at about the same image-time coordinates as P-P Horizon 1 (about 5 s) across the profile. Locally, P-P Horizon 1 and P-SV Horizon 1 differ. The important point is that in a broad perspective, the two horizons are essentially depth equivalent. This observation is a key principle. Many explorationists do not yet know how deep P-SV data can image. This data comparison provides critical information suggesting that P-SV data provide continuous, mappable reflections to the same depths as P-P data. A second point to emphasize is that local differences between P-P Horizon 1 and P-SV Horizon 1 are important only if these horizons are structural surfaces. Because the horizons are indicators of reflection quality (specifically indicating the base of deepest continuous reflections) and not structure surfaces, local differences between P-P Horizon 1 and P-SV Horizon 1 are not too critical.

A different situation exists for Horizon 2. It is difficult to find any mappable P-SV events at image times significantly below P-SV Horizon 1. Only a few short segments of deep P-SV events are labeled in Figure 3. In contrast, the P-P data contain a large population of deep Horizon 2 events (Figure 2). The lack of P-SV events near the super-deep depths of P-P Horizon 2 does not reduce the value of P-SV data for evaluating drilling targets down to depths of 30,000ft to 33,000ft (9 km to 10 km) in this area of the Gulf of Mexico basin.

The time-based horizons in Figures 2 and 3 need to be converted to depth for the depth-imaging capabilities of long-offset P-P and P-SV data to be better appreciated. The transformation from image time to depth was done using P-P rms migration velocities determined during seismic data processing. Examples of P-P rms velocities determined across part of the study area are shown in Figure 4. A north-south velocity profile is displayed to give a sense of the velocity behavior associated with the selected north-south P-P and P-SV seismic images (Figures 2 and 3). The velocity layering exhibits vertical oscillations and thickness changes in the image-time interval between 3 s and 6 s where propagating wavefields first encounter salt-related structures.

The offset scale bar on the velocity profile is helpful for recognizing locations where lateral velocity variations occur over distances of the same dimension as the positive and negative-offset range used in processing the 4-C OBC data. Lateral velocity changes of this physical scale will complicate deeper imaging. Below 6 s, the velocity layering is reasonably smooth and uniform. All velocity layers drop deeper at the north end of the profile (Figure 4) where the thickest sediment accumulation is encountered and where little high-velocity salt is present.

The basic message this depth-converted process provides is critical information for explorationists operating in the Gulf of Mexico basin. The key finding is that continuous, mappable reflections (Horizon 1) often extend to depths of 30,000ft to 33,000ft for P-P and P-SV data. Long-offset 4-C OBC data provide quality P-SV and P-P reflection images of Gulf of Mexico geology to challenging drilling depths. The fact that good quality, continuous P-P reflections extend down to 33,000-ft targets is not surprising. The fact that equivalent-quality P-SV reflections are obtained for these same target depths is important, new information.

Conclusions

OBC seismic technology allows long-offset seismic data to be acquired across congested production areas where long-offset towed-cable seismic technology is not feasible. Further, 4-C OBC seismic technology provides P-P and P-SV data. Towed-cable technology provides only P-P data.

Practical drilling targets across the Louisiana shelf are now limited to depths of about 33,000ft or less. Long-offset P-P and long-offset P-SV data provide quality, continuous reflections to these depths. The documentation that P-SV images are of a quality equal to that of P-P images at depths of 30,000ft to 33,000ft is critical information for operators wanting to use multicomponent seismic data for improved understanding of lithofacies distributions and overpressure conditions across deep prospects. The study confirms that a fundamental requirement for good imaging of deep targets is acquiring long-offset seismic data. These research findings should encourage operators in the Gulf of Mexico basin to integrate long-offset 4-C OBC seismic technology into their prospect evaluations, particularly in areas where there are congested production facilities. ✧

Acknowledgements

The seismic data shown in this article are multi-client data available from WesternGeco, who is thanked for allowing the data examples to be shown. Initial funding support for the research was provided by the Research Partnership to Secure Energy for America (Contract No. RPSEA-R-521A). Ongoing research support is provided by the U. S. Department of Energy (Program No. DE-PS26-04NT42072).

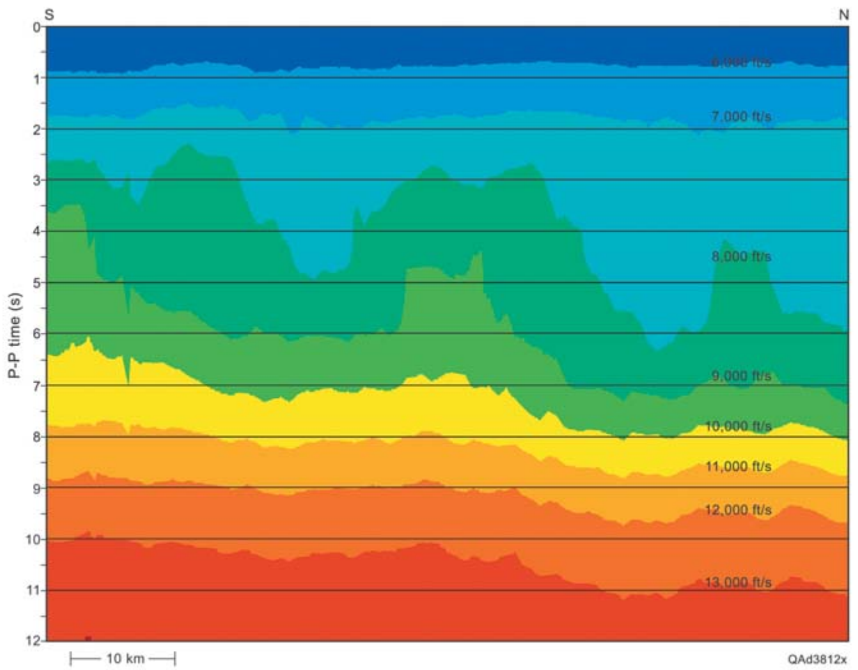


Figure 4. P-P rms migration velocities across the study area used to convert Horizons 1 and 2 to depth. Velocity values increase with time within each colored layer.

Integrated Seismic/Rock Physics Approach to Characterizing Fractured Reservoirs

By Gary Mavko, Diana Sava, Juan-Mauricio Florez and Tapan Mukerji,
Rock Physics Laboratory, Stanford University

The key to successful development of many low permeability reservoirs lies in reliably detecting, characterizing and mapping natural fractures. Fractures play a crucial role in controlling fluid transport in tight reservoirs, and they can influence production, sometimes adversely, even in reservoirs with moderate to high permeability.

Most seismic methods to map fractures depend on a few anisotropic wave propagation signatures that can arise from aligned fractures. Common among these are shear wave splitting, azimuthal and offset variations of seismic P-wave amplitude, and azimuthal variation in P-wave normal moveout velocity. While seismic anisotropy can be a powerful fracture diagnostic, a number of situations can lessen its usefulness or introduce interpretation ambiguities, including:

- multiple fracture sets at different orientations that combine to lessen the anisotropy;
- the presence of nonfracture rock anisotropy as might occur with large differences in horizontal principal stresses;
- fracture occurrence in narrow bands or swarms that are not sampled well by azimuthal methods; and
- seismic acquisition geometries that provide limited azimuthal coverage.

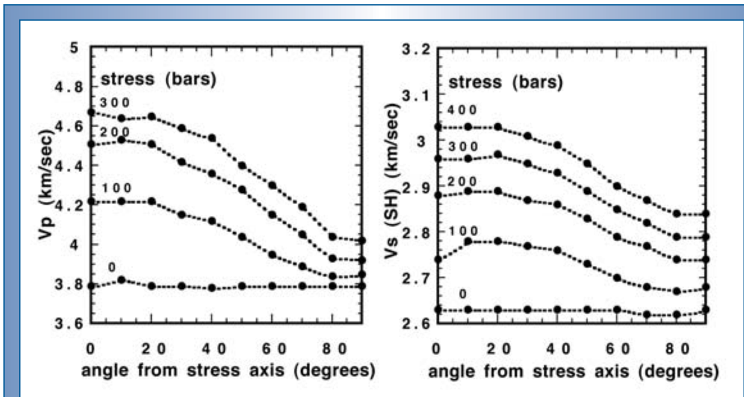


Figure 1. Ultrasonic P- and S-wave velocities vs. the direction of wave propagation relative to the direction of applied uniaxial compression.

Laboratory and theoretical work in rock physics indicates that a broader spectrum of fracture seismic signatures can occur, including a decrease in P- and S-wave velocities, a change in Poisson's ratio, an increase in velocity dispersion and wave attenuation, as well as indirect images of structural features that can control fracture occurrence.

In this article, we summarize an interpretation and integration strategy for detecting and characterizing natural fractures in rocks.

The goal of rock physics is to discover, understand and quantify the links between geophysical measurements and the underlying rock properties. In the case of fractures, our models help quantify links between seismic observables and fracture density, orientation, pore fluid and permeability.

The physical mechanism of the elastic fracture effect is simple: fractures, whether wet or dry, soften the rock in a way that depends on the fracture direction. The fracture-induced reduction in elastic stiffness translates directly into reduction of seismic P- and S-wave velocities, reduction in impedance and a change in Poisson's ratio. If the fractures are aligned, then these fracture signatures tend to be directionally dependent, resulting in seismic anisotropy.

The historical basis for modern seismic methods for fracture detection was the classic stress-induced velocity anisotropy experiment by Nur and Simmons (1969), illustrated in Figure 1. The experiment was performed on a sample of granite under various levels of uniaxial compressive stress. The plots show P-wave and S-wave velocities vs. direction of wave propagation relative to the direction of applied pressure. The cracks appear to be initially isotropically distributed, because the velocities are independent of direction at zero stress. As uniaxial stress is applied, crack anisotropy is induced. The velocities vary with direction relative to the stress-induced crack alignment. It is these fracture-related velocity changes that we look for in the field.

Integrated strategy for fracture characterization

Different types of information can be used for fracture characterization. Outcrop studies give direct observations of the fracture orientation, spatial density and sometimes their lengths. Outcrops also lend insight into geomechanical relations, such as how fractures are related to strain, bed thickness and facies brittleness. The challenge is to extrapolate this

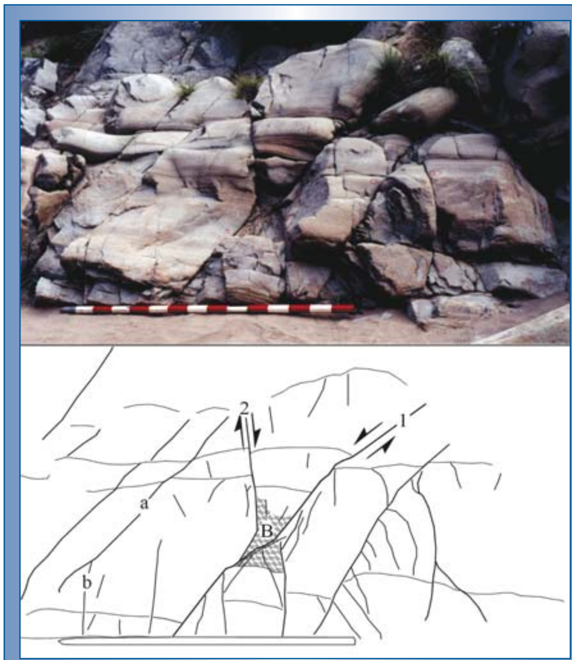


Figure 2. Outcrop examples of tectonic bowties.

information to the reservoir at depth. Seismic data, on the other hand, provide good coverage at depth, but the measurements are indirectly related to fractures, and their resolution is lower than the scale of the features in which we are interested. Nevertheless, seismic attributes yield information about fracture density, orientation and sometimes the type of fluid saturating the fractures.

Our approach is to integrate the geologic, well log and seismic information in the framework of an inverse problem, as defined by Tarantola (1982, 1987). The inverse problem has three different elements:

- the *model parameters*, represented by the fracture characteristics that we wish to map;
- the *data parameters*, such as seismic and log measurements; and
- the *rock physics* theories that relate the model parameters to the data. There also often is prior information about the subsurface fracture parameters from geologic constraints.

A general way to express the prior geologic knowledge about the fractures is through *a priori* probability density functions (PDFs). We can think of the prior model as the geologist's best prediction of where the fractures are likely to be, before seeing the quantitative seismic information. Expressing the prior model as a PDF allows us to describe multiple likely fracture hypotheses, while at the same time quantifying our level of confidence in the predictions. The geophysical data, which are affected by measurement errors, also can be described through PDFs. Finally, the theoretical relations between the fracture characteristics and the seismic data can incorporate PDFs to account for approximations in the models and natural variability of the input rock properties.

Probability theory allows us to integrate the various types of information and, at the same time, to estimate the uncertainty in our predictions. The solution is represented by the *a posteriori* PDF for the fracture characteristics, from which we can obtain the expected values for fracture parameters, as well as maps of uncertainty.

The workflow we have developed consists of the following steps:

- analysis of the geologic scenarios, including stratigraphic and structural controls on fracture occurrence. The results of this step are a list of likely fracture scenarios to evaluate – Which intervals might be fractured? How many fracture sets might exist? What pore fluids should be considered? – constraints on fracture occurrence, and a prior fracture model, expressed as a PDF;
- rock physics fracture modeling, to explore the seismic signatures of the plausible fracture distributions at the site;
- analysis of field seismic data to identify potential artifacts, and extract attributes that will be useful for the fracture interpretation; and
- integration of the prior information, the theoretical relations and the geophysical data to produce the final fracture interpretation as well as quantitative estimates of uncertainty.

Geologic model of fracture occurrence in a fractured carbonate

With the cooperation of Marathon Oil, we received well logs, seismic, lithologic descriptions and geologic insights into a fractured tight carbonate field in East Texas. The dominant structural style in the field site is normal faulting and the current state of stress is extensional. The intervals of interest consist of the interposition of layers of limestone and calcareous shales at a variety of scales, which impose important controls on the mechanism and styles of fracture formation.

We have developed a model for the evolution of conjugate normal faults in sedimentary sequences, such as this, having high brittle/ductile contrast. Slip along ductile (shaly) bedding surfaces creates stress perturbations that result in the formation of subvertical splay joints. Slip along these subvertical splay joints generates a new stress perturbation that creates a new set of splay joints. The new splay joints constitute new low-friction planes that slip, forming a set of conjugate normal faults.

This evolution of conjugate normal faults results in a particular shape called the tectonic bowtie, (Figure 2). The limits of the bowtie are defined by the parent (synthetic) normal fault and the main two opposite-dipping antithetic faults. The zones between the parent fault and the antithetic faults are characterized by high-density fracture swarms, parallel to the parent fault. Fracture swarms may occur associated with faults with less than 16½ft of offset, and are therefore below the seismic resolution. These fracture swarms, however, have a significant impact on rock impedance.

Integration of a multi-offset vertical seismic

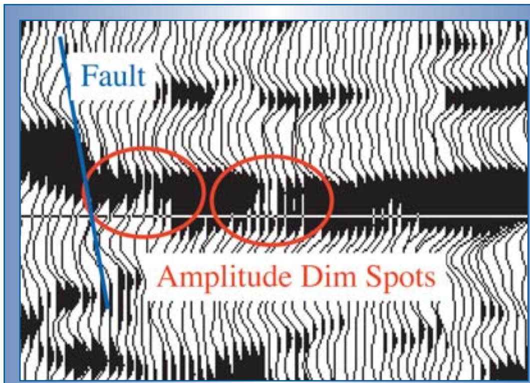


Figure 3. Fracture-induced amplitude dim spots near a large fault.

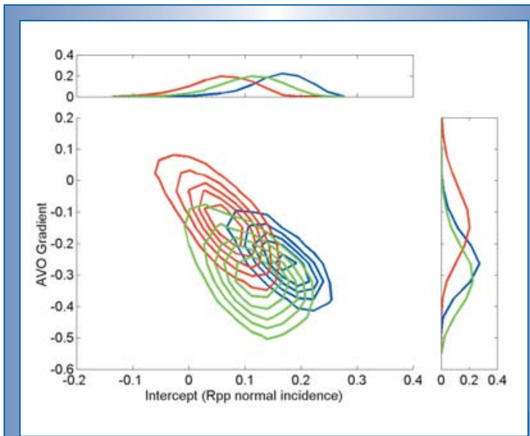


Figure 4. Joint probability distribution functions of the AVO gradient and intercept for the Monte Carlo simulations of the unfractured, clean limestones (blue), fractured limestones with randomly oriented cracks (green) and shaly rocks (red). The fractures are filled with gas.

profile (VSP) and a horizontal well, confirms the presence of subseismic faults and fracture swarms within the limestone. The presence of small faults is indicated by changes in the stratigraphy along the well trajectory, as well as by small displacements of the top reflection observed in the VSP data. These faults also are associated with reduction in the P-to-P reflectivity ("dim spots"), most likely related to fracture swarms (Figure 3).

Rock physics analysis and fracture modeling

The reservoir is modeled with two types of fracture distributions: localized bowtie fracture swarms, within which the fractures can be more or less randomly oriented; and a more uniformly distributed set of aligned vertical joints that generate an azimuthally anisotropic medium. Log analysis indicates three main facies: unfractured clean limestones; shaly limestones; and clean limestones. FMI data indicate that the fractures tend to occur in the cleaner (clay-free) limestone intervals, which have lower porosities and higher velocities. The goal of the rock physics analysis is to find the optimal combination of seismic attributes for distinguishing the gas-filled fractured zones from the shaly and unfractured limestones in the reservoir.

For each of the fracture distributions, we stochastically modeled seismic interval and interface properties such as interval velocities, impedances, travel times, and P-to-P reflectivity as functions of angle of incidence and azimuth. The modeling shows that all these properties may be influenced by the presence of the fractures, with gas-filled fractures generally more visible than brine-filled fractures.

The AVO gradient-intercept domain is potentially useful for detecting gas-filled fractures in the reservoir. As the fracture density increases in the clean limestones, the P-to-P reflectivity from the fractured zones decreases and becomes indistinguishable from the P-to-P reflectivity from shaly limestones. However, shaliness moves the AVO gradient to smaller negative values, while gas-filled fractures move the AVO gradient to larger negative values (Figure 4). Therefore, at this site, AVO gradient appears to be a good fracture indicator, while P-wave impedance, alone, is not.

The Integration Methodology

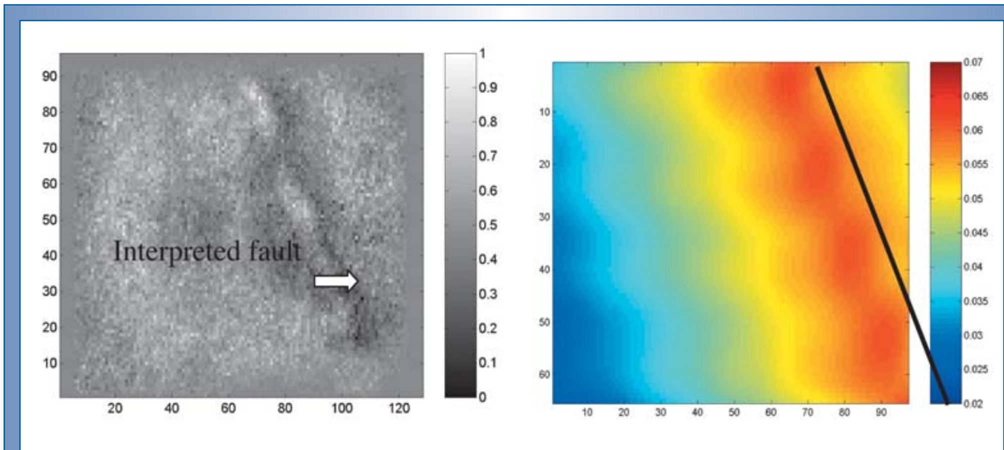


Figure 5. Left panel: *Amplitude map at the top of a fractured carbonate reservoir, with the interpreted fault. Bin size is 200ft.* Right panel: *Map with the* a priori *spatial distribution of the mean fracture density at the top of the reservoir, based on the interpreted fault.*

Prior information about fracture parameters

At our field site, the fracture occurrence is controlled primarily by the existing faults – both the localized intensely-damaged swarms associated with bed-scale normal faults and the more distributed background subvertical fractures associated with larger faults. Additional factors controlling fracture occurrence include bed thickness, bed curvature and local tectonic stresses.

Figure 5 shows a seismic horizon slice (left), from which a major fault is interpreted. A prior model of the mean fracture density is shown on the right, described as a decaying exponential with distance from the fault. The maximum expected fracture density near the fault is assumed to be about 0.07, which corresponds to an upper value for the crack density expected for a reservoir at about a 1-mile depth, based on a world-wide compilation by Crampin (1994). At each location, the prior PDF of fracture density is expressed as a truncated exponential, with the mean shown in Figure 5.

Rock-physics modeling and stochastic simulations: Theoretical PDF

Next, we perform rock-physics forward modeling and stochastic simulations based on the well-log data, under the chosen geological hypotheses. Using Monte Carlo simulations, we obtain a variety of realizations of plausible fracture parameters and seismic attributes that span the intrinsic natural variability of the rock properties. Based on these realizations, we can estimate the theoretical joint PDF describing the physical relations between the fracture parameters, such as fracture density, and the seismic attributes at our site. Figure 6 shows an example for the theoretical joint PDF of the fracture density and the azimuthal reflectivity anisotropy under the hypothesis of a single set of aligned vertical fractures. The rock physics theory predicts increasing azimuthal reflectivity anisotropy with increasing fracture density.

Seismic data

The data parameters are represented by various reflectivity attributes from a 3-D seismic dataset acquired over the reservoir. A pitfall is the artificial amplitude patterns associated with the acquisition footprint. Increasing the bin size helped remove the footprint, though at the expense of resolution.

Azimuthal analysis of the P-to-P reflectivity involves partial stacking of the data within different ranges of azimuth. There is a tradeoff between the azimuthal resolution, which requires small ranges of azimuth, and the signal-to-noise ratio that requires larger fold and implicitly larger azimuthal bins. For a fixed azimuthal range, we can increase the fold by increasing the bin size, at the expense of reducing the spatial resolution.

Under the hypothesis of a nearly vertical set of fractures, as indicated by FMI data, the reflectivity at far offsets varies with azimuth. Figure 7 shows the observed azimuthal reflectivity anisotropy at far offsets (left), with the associated standard deviations (right). The mean values as well as the standard deviations are derived using a bootstrap method to take into account the measurement errors associated with the reflectivity. The uncertainty because of measurement errors is assumed to be Gaussian.

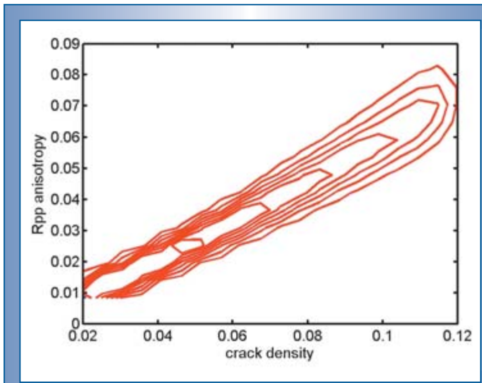


Figure 6. Theoretical joint PDF of crack density and azimuthal reflectivity anisotropy, derived based on the rock physics theories. The uncertainty is because of natural variability of the rock properties.

Quantitative integration of prior geological information with seismic data using rock physics

Finally, we quantitatively integrate the prior geological information and seismic data using the theoretical PDF, given by the rock physics theories. At each location, we derive the posterior PDF over the fracture parameters and data by multiplying the prior joint PDF on the fracture parameters and the seismic data, with the theoretical PDF, containing the rock physics information. We then integrate the a posteriori PDF over the seismic attributes space to obtain the updated distribution of fracture parameters. This posterior PDF represents the updated measure of uncertainty about the fracture parameters after integrating the prior geological information with the seismic data using rock physics theories.

From this a *posteriori* PDF of the fracture parameters, we can derive statistical quantities, such as expected values of fracture density, and confidence parameters, such as the probability that the fracture density exceeds certain thresholds. These probability maps help us assess the uncertainty in our predictions and can help us make informed decisions about the reservoir management.

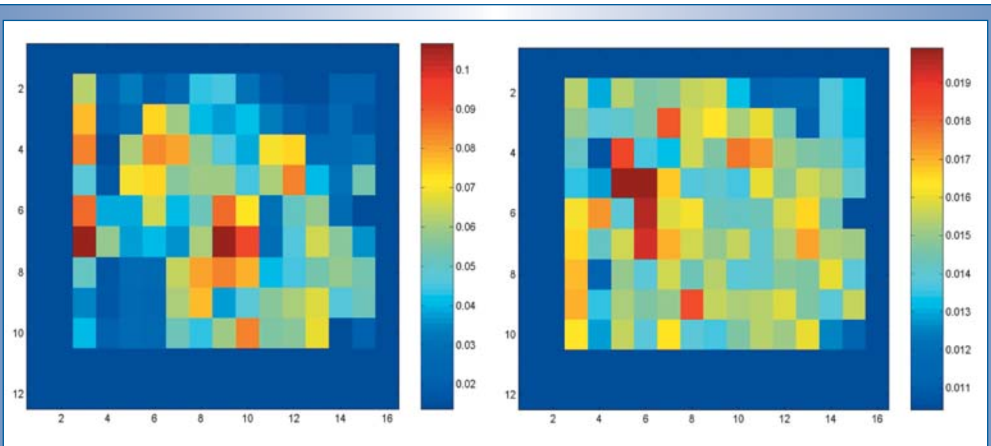


Figure 7. Left panel: *Map with the mean values of the azimuthal reflectivity anisotropy at far offsets at the top of the reservoir.* Right panel: *Standard deviations associated with the mean reflectivity anisotropy.*

Figure 8 shows a map with the spatial distribution of the posterior expected values for fracture density at the top of the reservoir, conditioned on the azimuthal anisotropy of reflectivity at far offsets. We observe a relatively higher fracture density near the fault, as the prior geological information suggests. We can also observe the asymmetric distribution of the expected crack density with respect to the fault, with higher values of fracture density in the hanging wall. This agrees with outcrop data. We also find other zones of higher fracture density away from the fault. These zones also may correspond to possible subseismic faults.

3-D Seismic data and AVAZ for fracture characterization

Once we observe an azimuthal variation in the seismic amplitudes, the challenge is to interpret it in terms of fracture density, orientation and fluid saturation. Rock physics modeling is a necessary step in interpreting the integrated fracture density map shown in Figure 8. The polarity of the amplitude variation with azimuth depends on gas saturation and fracture compliance. As a result, the azimuthal variation may be used to determine the saturation if the fracture orientation can be determined from other information. On the other hand, the saturation-compliance behavior can be a serious source of ambiguity. At our site, the rock physics models indicate that the fracture strike is in the minimum amplitude azimuth. From this, we derive a map with the fracture orientation and relative fracture density,. Using a bootstrap method, we also estimate the uncertainty in the fracture orientation and the azimuthal anisotropy in the reflectivity because of measurement errors (Figure 9).

Summary

We have presented an interpretation and integration strategy for detecting and characterizing natural fractures in rocks. We used a formalism based in probability theory to integrate prior geologic models of fracture occurrence, geophysical (log and seismic) data and theoretical rock physics models linking fractures, background rock properties and observable seismic attributes. In a field study of a fractured tight limestone, we find agreement between the mean fracture orientations derived from the azimuthal variation of the seismic amplitudes at far offsets and the fracture orientations derived from the FMI logs from a nearby well. There also is agreement between the mean fractures' strike from azimuthal variation of amplitude and the present regional stress field. The mean fracture orientations are approximately parallel to the maximum horizontal stress in the region. As expected from geomechanical considerations, we infer higher fracture densities in proximity to a seismically interpreted fault, with higher fracture density in the hanging wall. We also infer apparent high-fracture zones away from the fault, which can only be detected from the seismic.

A critical part of our work is careful rock physics modeling to provide the quantitative links between log, geologic and seismic information. ✧

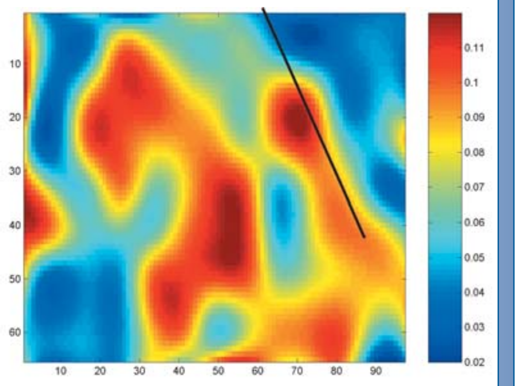


Figure 8. Map of the expected values of fracture density derived from the a posteriori *distribution, obtained by constraining the* a priori *geological information with the azimuthal anisotropy of reflectivity at far offsets, in the hypothesis of a vertical set of aligned fractures.*

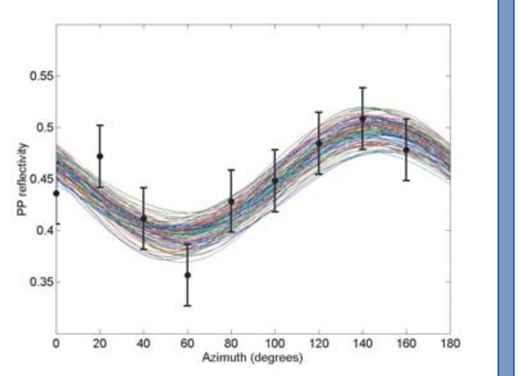


Figure 9. Picked amplitude variation with azimuth at a fixed superbin, and the 100 cosine fits obtained using a bootstrap method, taking into account the measurement errors represented by the error bars.

Acknowledgements

This work was supported by contract DE-AC26-99FT40692 from the U.S. Department of Energy, Federal Energy Technology Center and the Stanford Rock Physics and Borehole Geophysics project. We especially thank Marathon Oil for their participation and support.

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Dual-Density Drilling Systems Reduce Deepwater Drilling Costs: Part I—Concepts and Riser Gas Lift Method

By John Rogers Smith,
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and Mikolaj Stanislawek,
ENSCO

A study of dual-gradient deepwater drilling systems relying on riser gas lift and riser dilution concluded that both concepts are feasible and warrant additional research. Editors note: This is the first in a two-part series. The second part will publish in *GasTIPS* fall issue.

Development of the U.S. deepwater gas resources is limited by the high capital costs involved in developing these resources. Dual-gradient drilling methods have been proposed as a means to provide simpler, safer, more economic well designs and therefore increase the ultimate development and utilization of deepwater gas resources. Two dual-density drilling concepts – riser dilution with a low density liquid and riser gas lift – were investigated as potential means to implement a dual-gradient system. The overall objective was to establish whether further research concerning dual-density drilling systems based on use of low-density fluids, either liquid or gas, is justified. The investigation was conducted by the Craft and Hawkins Department of Petroleum Engineering at Louisiana State University and sponsored by the Research Partnership to Secure Energy for America.

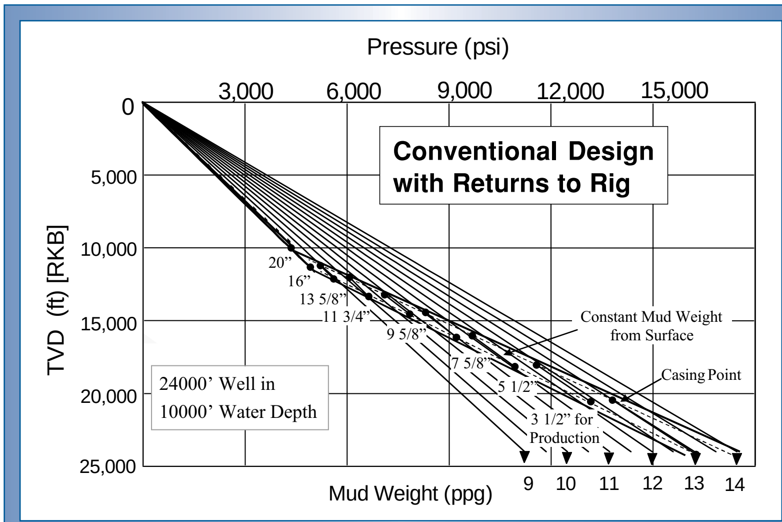

Figure 1. Conventional well design for 24,000-ft Gulf of Mexico well in 10,000ft of water.

The investigation focused on providing initial answers to several critical questions about the practical feasibility and potential commerciality of these two dual-density drilling methods. The first is the probable cost-benefit relationship for each. The second is whether effective well control methods can be defined. The third question is the practicality of separating the low-density and high-density components of the mixed fluid that returns to the surface in the riser for reuse.

The cost reduction when using a riser gas lift approach was estimated to be at least 9%, and most likely 17% to 24%, vs. estimated trouble-free costs for conventional drilling of three example wells selected to represent future deepwater Gulf of Mexico operations. In addition, a riser gas lift approach also increased the feasibility of drilling deep wells in deepwater that might otherwise be impossible. Well control with a riser gas lift system also was found to be feasible when using methods generally analogous to conventional operations or to use a subsea mudlift pump. Riser dilution using liquids was estimated to reduce costs vs. conventional operations by 7% for the example studied. The practicality of separating and reusing mud returning from the riser for a liquid dilution system was only partially investigated. However, results from this work and that done by de Boer (2003) indicate mud separation and reuse in a riser dilution system is possible.

This article will focus on the concepts and rationale for dual-density drilling and the investigation of riser gas lift as one mechanism for achieving a dual-gradient system. Part 2 will focus on liquid dilution of fluids in the riser as an alternative means for achieving a dual-gradient system as well as the expected costs savings from using dual-density instead of conventional drilling methods.

The rationale for investigating these dual-

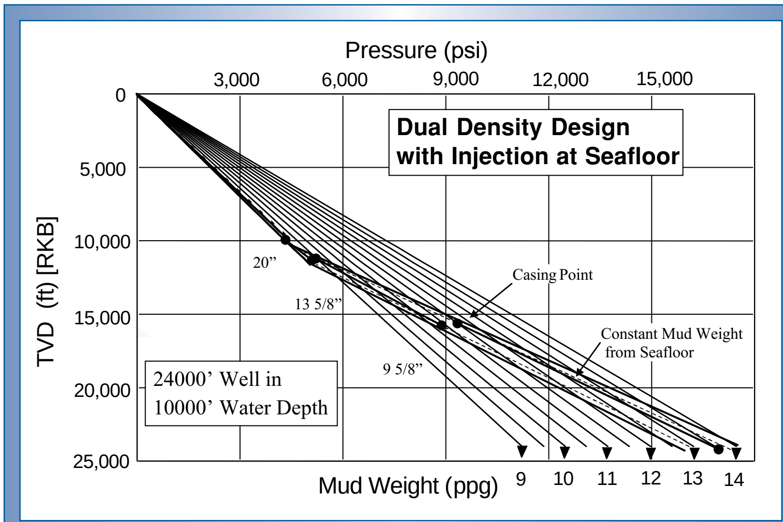

Figure 2. Well design for 24,000-ft Gulf of Mexico well in 10,000ft of water using the dual-density concept.

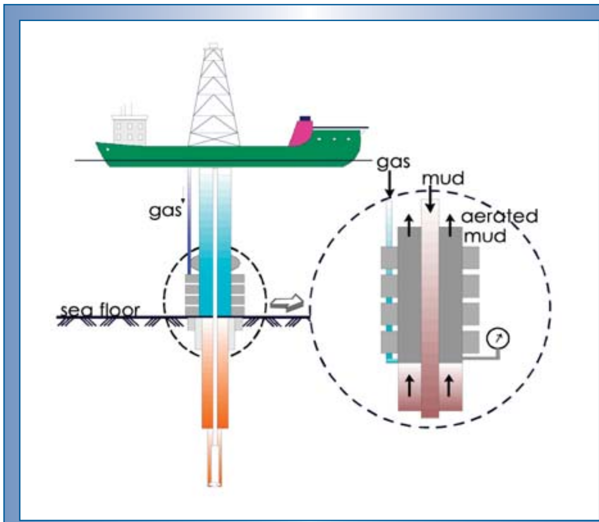

Figure 3. Schematic of the riser gas lift method. (Source: Lopes, 1997)

density drilling methods is the expectation that development of deepwater natural gas reserves should contribute significantly to new gas reserves in the lower 48 states during the next 15 years, according to recent Gas Technology Institute (GTI) baseline projections. However, the current economic significance of deepwater gas production is constrained by the substantial capital costs of deepwater development. Effective dual-density drilling systems could potentially remove that constraint.

Even though wells have been drilled in water as deep as 10,000ft, the riser inside diameter can severely limit the number of casing strings that can be used and consequently the maximum practical well depth when conventional well designs are used. These limits become more severe with increasing water depth. An example of a conventional well design for a 24,000-ft well in 10,000ft of water is shown in Figure 1. Use of a single mud density from the well bottom to the surface results in wellbore pressures that can only be contained over a short distance of drilling without setting casing and increasing the mud density. An example interval is labeled "constant mud weight from surface" in Figure 1. The result in this case is that eight casing strings ranging in size from 20-in. to 3.5-in. are required to reach and set casing at the total depth of 24,000ft.

Specific geologic conditions, such as long salt intervals, or more costly well equipment, such as expandable tubulars, can offset the limitations on maximum practical depth or casing size at total depth (TD). Nevertheless, some deepwater resources will be left unexplored or undeveloped because the current well design technology is too limited or costly to be economically feasible.

A simpler, potentially more cost-effective well design would use a moderate density fluid in the annulus of the riser and a higher density fluid in the wellbore to provide a more favorable pressure profile in the well, specifically a pressure profile closer to what naturally exists in the subsurface formations. The drilling system that would allow these two different fluid gradients in the well has been called the dual-density or dual-gradient system. An example of how the fluid gradients and casing points in this kind of well design would correspond with formation pressure gradients is provided in Figure 2.

The water depth, well depth, pore pressures and fracture pressures in Figure 2 are the same as in Figure 1. However, use of a higher density fluid in the wellbore and a lower fluid density in the riser give wellbore pressures that only require three casing strings to reach and set casing at TD. In this case, the casing at TD could easily be 9.625-in., which would allow economic well production rates that would be impossible with the 3½-in. casing in the conventional design. Ultimately, the dual-density well design has the advantages of fewer casing strings for lower well cost, larger mud weight margins for improved safety, a larger production casing size for increased production and revenue rates, and reduced riser tension requirements that would allow longer risers to be used with existing tensioning systems.

Several industry projects have been conducted to address the potential of the dual-gradient concept. The subsea mudlift drilling project led by Conoco and Hydril developed prototype seafloor pumps that were used in a successful offshore field trial. The Deepvision concept also used seafloor pumps and was researched by Baker-Hughes and Transocean. The concept of using hollow glass beads to reduce the density of riser fluids was researched by Maurer Technology, and a previous, preliminary feasibility study of the riser gas lift concept was performed by LSU and Petrobras. Dual-Gradient Systems has pilot-tested a patented liquid dilution system. However, none of these systems has reached commercial application, and the riser gas lift and liquid dilution methods have received less attention than the pump-based systems even though they potentially require less rig modification and initial investment to put into service.

Project description

The overall objective of this project was to establish whether more comprehensive research concerning dual-density drilling systems based on use of low-density fluids, either liquid or gas, is justified. The project was intended to continue the research initiated by LSU and Petrobras on the riser gas lift method (Figure 3) and begin assessing injection of unweighted liquid into the riser as another alternative. These methods are intended to offer alternative methods of achieving a dual-gradient deepwater drilling system that utilize more standard equipment than the separate industry projects focused on the use of seafloor pumps to achieve the advantages of a dual-gradient method.

The focus of the project has been to evaluate and develop the operational concepts for two dual-density methods that can be applied using current riser-supported subsea drilling systems: riser gas lift and injection of an unweighted liquid into the base of the riser to dilute the wellbore fluids entering the riser. The results are intended to provide a first step toward answering critical questions about the practical feasibility and commerciality of these systems.

The primary business question is what the probable cost-benefit relationship would be for each of the two alternative concepts if applied to deepwater Gulf of Mexico development and exploratory wells. This question was addressed by applying dual-density design concepts to three representative deepwater well designs and considering the cost impacts of the different designs and rig equipment requirements. The principle technical question is whether an effective well control method can be defined for a system containing so many different density fluids and flow paths. This question was addressed primarily by simulating well control operations for representative situations using a transient multiphase flow simulator. An additional concern is the practicality of separating the mixed fluid that returns to the surface into low-density and high-density flow streams for reuse. This concern was addressed by studying lab formulations of candidate mud systems as well as using a lab centrifuge and a hydroclone to separate a riser mud into low-density and high-density flow streams to be used as dilution fluid and wellbore fluid, respectively.

Riser gas lift

The conceptual feasibility of riser gas lift is dependent on achieving a significantly lower effective density in the riser than in the well. Figure 4 shows the result of one study demonstrating the feasibility of achieving a wellhead pressure equivalent to the seawater

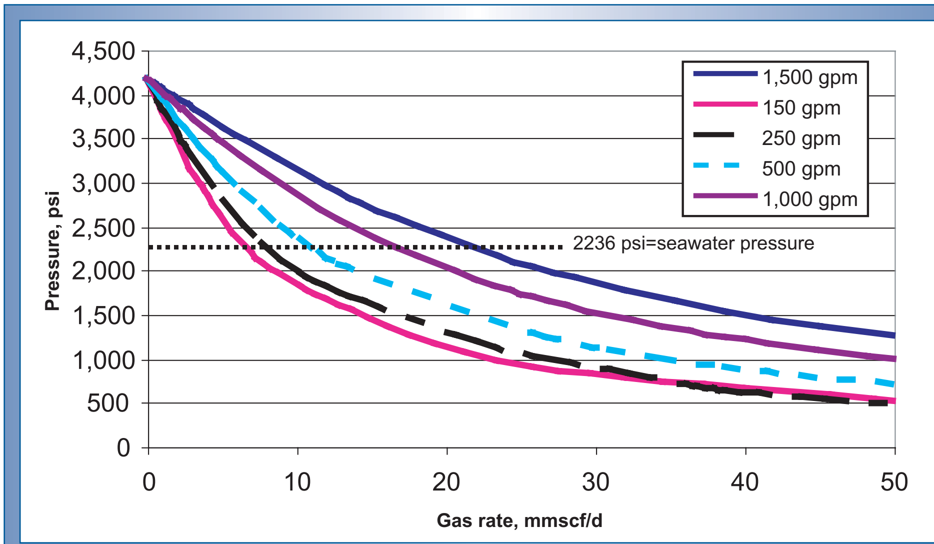

Figure 4. Wellhead pressure with riser gas lift using 16 ppg mud at 5000-ft water depth.

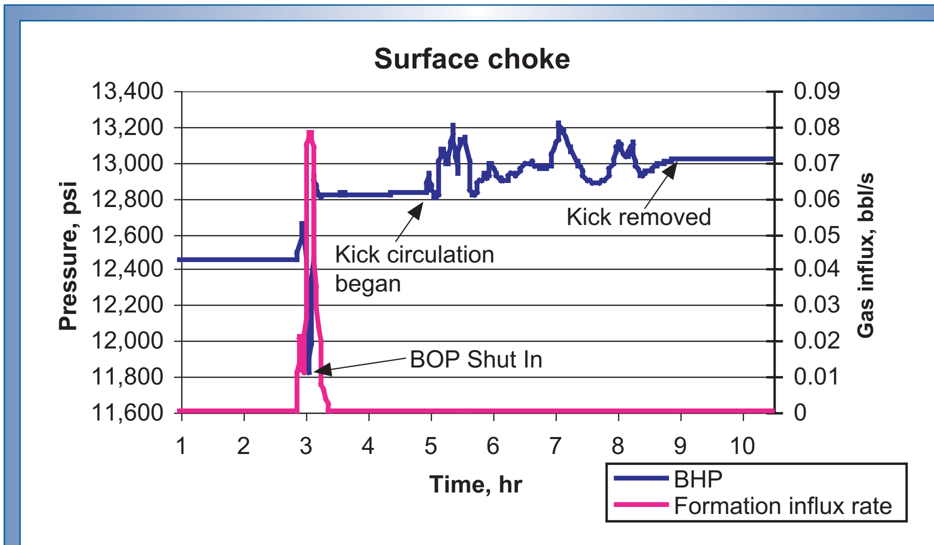

Figure 5. Simulation of bottomhole pressure and formation flow rate during well control.

hydrostatic pressure over a range of circulating rates with 16 ppg mud in a 19¼-in. inside diameter riser in 5,000ft of water.

A primary concern was whether an effective well control method could be defined for a system containing the many different density fluids and different flow paths inherent with a riser gas-lift system. The specific concerns addressed were kick detection, cessation of formation feed-in and removal of kick fluids with a constant bottomhole pressure method. These concerns were studied using OLGA2000™, a transient multiphase simulator. The validity of using the simulator to study this system was confirmed by comparison to transient multiphase flow data from a test well.

Conventional kick detection methods relying on the pit gain and return flow rate were concluded to be effective. However, a flow check to determine a kick is in progress is not possible. Two alternatives for stopping formation flow were considered, a "load-up" method of reducing the nitrogen rate vs. closing a subsea blowout preventer (BOP). BOP closure was shown to be faster and more reliable for stopping flow and minimizing kick volume.

Figure 5 shows the results from an example simulation of well control with riser gas lift. In this case, the well was shut-in with the BOP, and then the kick fluids were circulated out through the choke line and a surface choke using essentially conventional methods. Based on simulations like this of several different alternatives, it was concluded that methods using a choke with returns up the choke line were simpler and more effective than alternatives with returns up the riser and/or using nitrogen rate adjustments to control wellbore pressure. Bottomhole pressure was maintained relatively constant using only choke adjustments and no variation in the nitrogen injection rate, which should indicate that implementation of successful well control in the field would be relatively straightforward. However, the variation in bottomhole pressure was larger than typically desired. The cause of this variation is two-fold. The first cause is that there is always a gas phase in the choke line, which makes the effect of a surface choke pressure adjustment less predictable than for a system that has liquid in the choke lines. Using a remote-controlled seafloor choke upstream of the choke line could alleviate this. The other cause relates to the simulator rather than to the real system. The simulator runs only in a batch mode, which prevents simple or quick correction of choke pressure and requires rerunning the simulation each time a wrong adjustment in choke pressure is made. Consequently, it is difficult and time-consuming to get simulations with exactly the desired results, and those shown were deemed acceptable for the purpose of showing system feasibility.

There are some differences vs. conventional well control. Nitrogen injection into the base of the choke line lowers wellhead pressure, which alleviates the concerns relating to excessive bottomhole pressure because of choke line friction that occurs in conventional well control. One additional item of equipment vs. that in a conventional system also would be desirable. Use of a drillstring valve that has been developed for use with the subsea mudlift drilling system would prevent excessive bottomhole pressure when the well is on choke with the drillstring filled with heavy wellbore mud.

Overall, well control with a riser gas-lift approach to dual-density drilling should be practical using essentially conventional methods.

Conclusion

This article has focused on the rationale for dual-density drilling and the different concepts for implementing a dual-gradient system. It also describes the investigation of riser gas lift as one mechanism for achieving a dual-gradient system, and concludes that riser gas lift is operationally feasible and well control operations will be essentially conventional. Part 2 of this series will focus on liquid dilution of fluids in the riser as an alternative means for achieving a dual-gradient system as well as the expected costs savings from using dual-density instead of conventional drilling methods.

Detailed reports on all parts of the project to investigate the feasibility and economics of these dual-density systems are available as publications on the GTI Web site, *www.gastechnology.org* ✧

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Laboratory Testing of an Active Drilling Vibration Monitoring & Control System

By Martin E. Cobern,
APS Technology; and
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APS Oilfield Services LP

The deep, hard-rock drilling environment induces severe vibrations, which can cause reduced rates of penetration and premature failure of the equipment. An active vibration control system can prevent such problems and increase the rate of penetration.

APS Technology is developing a unique system to monitor and control drilling. This system has two primary elements: an active vibration damper (AVD) to minimize harmful vibrations, whose hardness is continuously adjusted; and a real-time system to monitor drillstring vibration and related parameters. This monitor adjusts the damper according to local conditions.

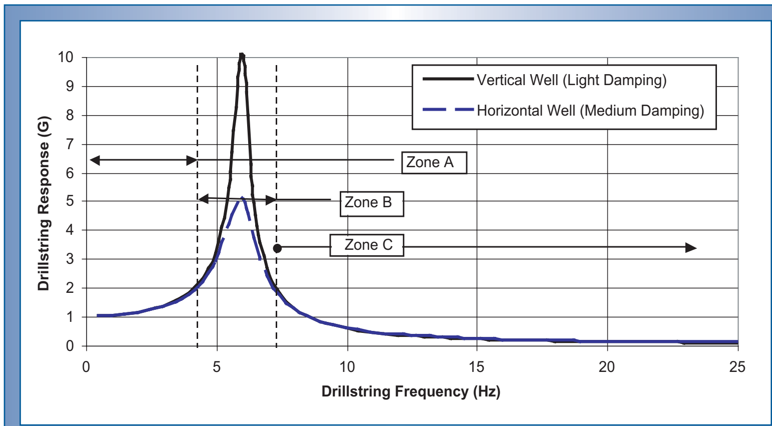

Figure 1. The frequency response of a typical drillstring.

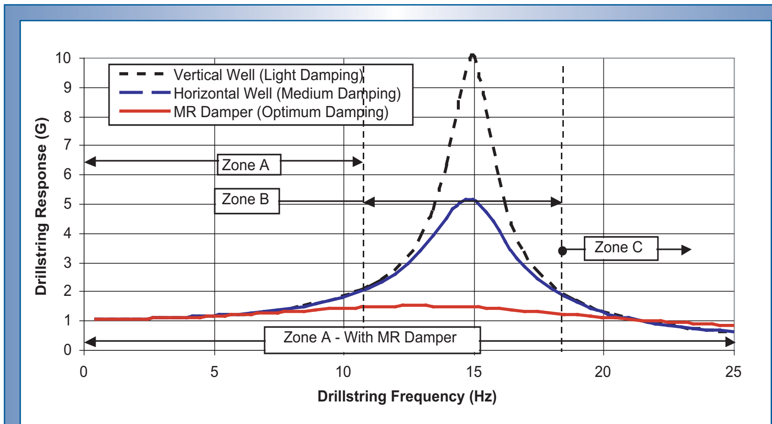

Figure 2. Typical drillstring response with an active vibration damper in use.

The AVD is designed to have several favorable effects on the time needed to drill a well. By keeping the bit in constant contact with the well bottom and maintaining the actual weight-on-bit (WOB) at the optimum level, the instantaneous rate of penetration (ROP) is increased. Additionally, by reducing the levels of vibration throughout the bottom-hole assembly (BHA), the operating life of all downhole components, such as bits, motors and measurement-while-drilling systems, is increased, thereby reducing the number of trips required for a particular well. These advantages will apply in all wells, but their value increases disproportionately in deep drilling.

An earlier paper reported on the design and modeling of this system. After briefly reviewing these, we present preliminary laboratory tests illustrating the ability of the AVD to adjust to a range of downhole conditions. Field test prototypes are being designed and built, and will be field tested this year.

The drilling environment, and especially hard-rock drilling, induces severe vibrations into the drillstring. The results of the vibrations are premature equipment failure and reduced ROP. The only way to control vibration with current monitoring technology is to change the rotary speed or WOB. These changes may move the drilling parameters away from their optimum value and may have a negative effect on drilling efficiency.

Shock subs are not a universal solution, since they are designed for one set of conditions. When the drilling environment changes, shock subs become ineffective and may result in increased drilling vibrations.

Drillstrings develop vibrations when run at critical rotary speeds. These vibrations are difficult to control because of the strings' long length and large mass. Operating at a critical speed can impart severe shock and vibration damage to the drillstring, and fatigue drill collars and rotary connections. Vibrations also cause the drillstring to lift off the bottom, reducing ROP. The effect of axial, lateral or torsional

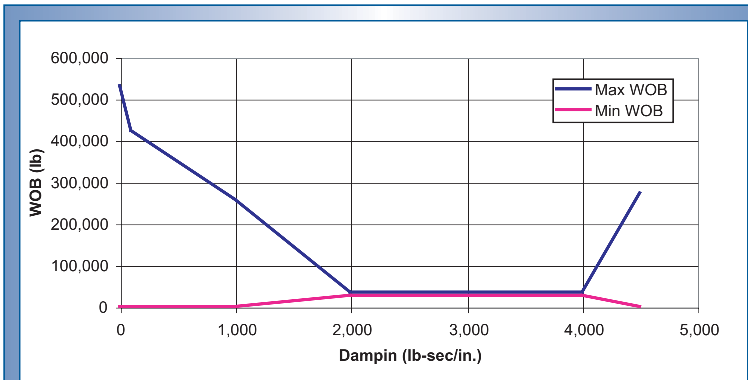

Figure 3. Measured weight-on-bit: 30,000 WOB – 30,000-in.-lb spring rate.

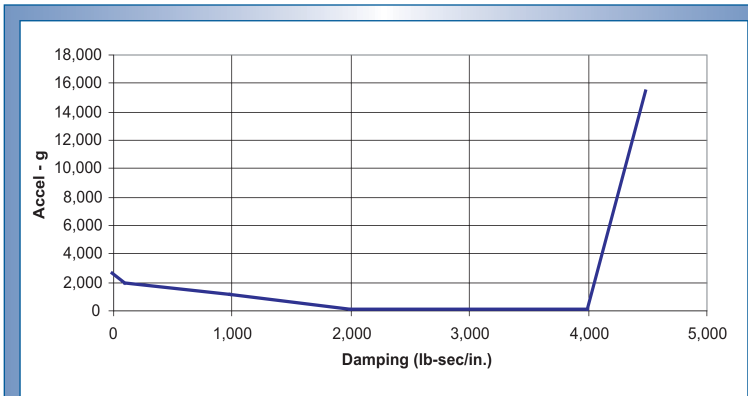

Figure 4. Bit acceleration: 30,000 WOB – 30,000-in.-lb spring rate.

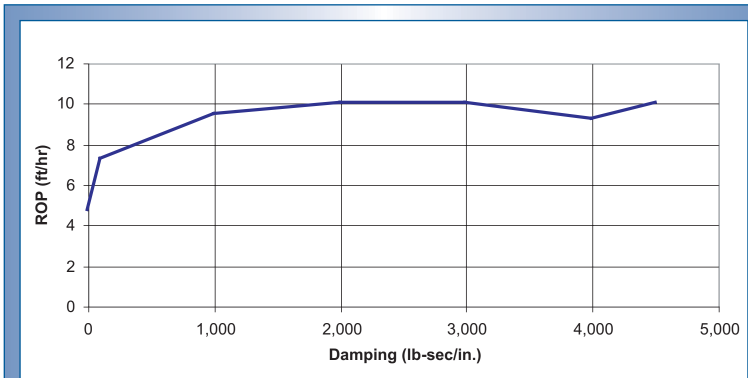

Figure 5. Rate of penetration: 30,000 WOB – 30,000-in.-lb spring rate.

(stick-slip or bit whirl) vibration upon drilling has been documented in the laboratory and the field.

The natural frequencies of the drillstring often fall in the range excited by typical drilling speeds: between 0.5 Hz and 10 Hz, depending on the BHA and length of the drillstring. There are many sources that excite drillstring vibrations, including bits, motors, stabilizers and drillstring imbalance. For example, a tri-cone bit imparts a primary excitation frequency of three times the rotary speed. If rotating between 120 rpm and 180 rpm, the excitation frequency is between 6 Hz and 9 Hz.

Mud motors also are significant sources of excitations on the drillstring. The rotor of the mud motor moves in an eccentric orbit that oscillates several times per revolution. Depending on the lobe configuration of the motor, excitations occur between 1 Hz and 30 Hz. Shocks from bit bounce and collar impacts against the borehole result in higher frequency vibration.

The best situation for a drillstring is to operate below its lowest critical speed. By staying below this first critical speed, drilling frequencies do not excite the drillstring and the bit maintains contact with the cutting surface of the borehole. In Figure 1, this safe range is Zone A. In this example, with a fundamental natural frequency of 6 Hz, Zone A extends to 4 Hz, corresponding to a rotary speed to 80 rpm or less for a tri-cone bit. Zone B is the resonant range that results in high levels of vibration. Shock and vibration damage and low ROP occur in this zone. Zone C is above the first critical speed of the drillstring. Vibrations levels are reduced compared with Zone A and B; however, the bit does not maintain continuous contact with the drilling surface, since the natural frequency of the drillstring is lower than the excitations of the bit, preventing it from reacting to irregularities in the bottom. This discontinuous contact with the drilling surface of the borehole greatly reduces the ROP.

Principles of operation

The AVD consists of electronics that monitor vibrations and other drilling parameters, and a spring-fluid damper that controls the vibration. The damper properties are continuously modified to provide optimal damping characteristics for the conditions. A key innovation in the AVD is the use of magnetorheological fluid (MRF) as the means of varying the damping coefficient of the AVD.

MRF is a “smart” fluid whose viscous properties are changed by passing a magnetic field through it. The fluid’s components have no moving parts, rapid response times and low power requirements. The damping properties can be optimized to detune the drillstring from resonant vibration.

MRF damping is being used in such diverse applications as sophisticated automotive suspensions and earthquake protection systems for buildings and bridges. The AVD modifies the properties of the BHA in two ways that combine to increase ROP and reduce vibration. First, the damper decouples the drillstring section below the damper from the one above it. Second, it optimizes the damping based upon the excitation forces, significantly reducing the vibration. The combination allows the bit to respond more quickly to discontinuities on the cutting surface, while maintaining the desired surface contact force.

Separating the bit from the rest of the drillstring with a spring-damper assembly reduces the effective mass that must respond to discontinuities of the drilled surface. Reducing the mass increases the first critical speed of the drillstring attached to the bit, while the adaptive damping reduces the magnitude of vibration at the resonance. This provides a wider Zone A, (Figure 2, which is based on a simple model of the damper). For a tri-cone bit, Zone A now covers a range between 0 rpm and 220 rpm, a significant improvement compared with the 0 rpm to 80 rpm in Figure 1.

The practical effects of these changes are shown in the following figures, which are based on BHA models performed with APS's WellDrill™ software. When the damping coefficient is optimized, for this case to between 200 lb-sec./in. and 300 lb-sec/in., the bit remains in contact with the formation, the WOB remains constant (Figure 3), bit vibration is essentially eliminated (Figure 4), and the ROP increases (Figure 5). *Note: When WOB goes to zero, the bit is off bottom.*

Tool design

An overview of the AVD tool is shown in Figure 6. The tool has many features of a conventional shock sub, including a stack of Belleville washers to support the weight applied to the bit and bearings to absorb the axial and torsional loads. The key difference is that the damping coefficient is continually adjustable by varying the magnetic field applied to the MRF. The details of the MRF damper design are shown in Figure 7. This drawing is of an earlier test piece, but the configuration is largely unchanged in the prototype tools. The MRF will be in the volume between the housing (1) and mandrel (2). A series of coils wrapped in the grooves in the mandrel (in the latest design, the coils are in the outer housing, not the mandrel) will create bucking fields, which will be strongest in the gaps between the coils. The MRF in these areas will become more viscous as a function of the field strength, thereby varying the damping of the motion of the mandrel relative to the housing.

The MRF damper control algorithm utilizes displacement measurements taken in real time during the drilling operation. Based on this information, the damping properties are continuously modified throughout the drilling process. The intent is to reduce the motion of the bit relative to the well bottom and smooth out the vibrations above the damper. A hardening damper algorithm was developed as the simplest and most robust method to control damping (Figure 8). This method increases damping levels as the damper sections displace relative to one another. For small displacements and low WOB, a low level of damping is provided. As the deflection increases, because of higher WOB or larger vibration levels, the damping is increased. This method was shown analytically to provide proper damping levels throughout a range of conditions with minimal sensor data.

The new AVD tool prototype design uses a Belleville spring stack with a compound spring rate. This provides better isolation at various levels of vibration and WOB compared with shock subs having a linear spring rate, which provides increased deflection for the damping module at low levels of vibration and improved support at high levels.

Test bench

In operation, the AVD will be supported and loaded by the entire drillstring above it. Considerable weight is applied from above, which will have resilience and damping. The damping will result from the intrinsic damping in the drillstring, from the hydraulic damping of the drilling fluid and from contact with the borehole walls. At the bit, the driving force is the interaction of the bit and the irregular bottom of the hole. This interaction will have a primary frequency, such as triple the rotation rate for a tri-cone bit, but may have other harmonics as well if there is more than one high point on the well bottom. In addition, the well bottom is not

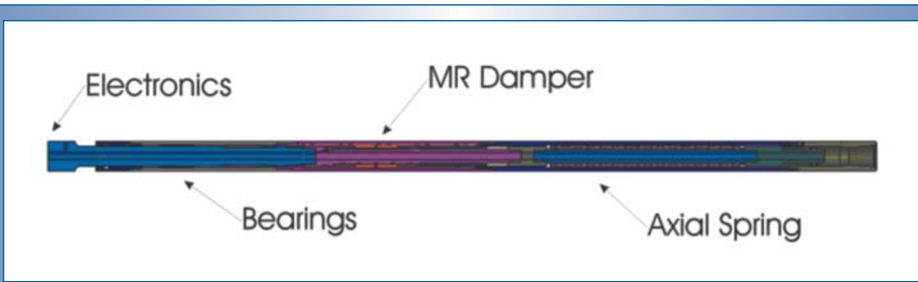

Figure 6. Overview of active vibration damper sub.

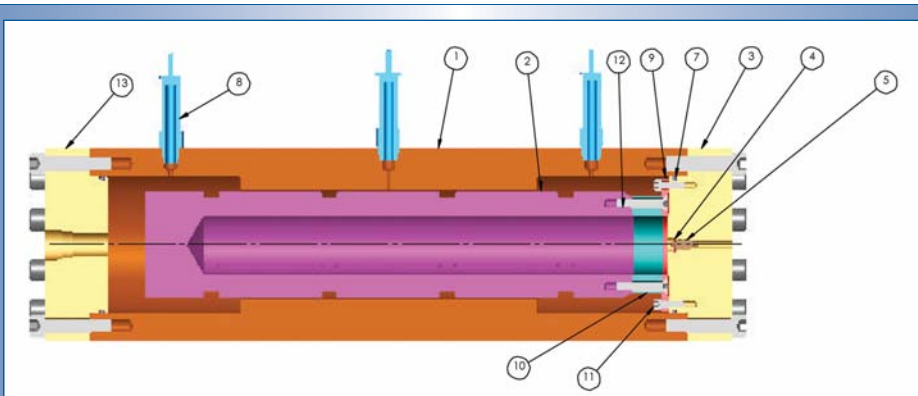

Figure 7. Detail view of the adjustable damping element design.

completely rigid but can respond to the bit by flexing or being drilled away.

To simulate these conditions, we designed the test bench (Figure 9). The prototype (5) is supported by linear bearings (4) on a large load frame (6). At the "uphole" end, to the left, a large pneumatic cylinder (1) applies a force simulating the loading from the drillstring above the tool. The damping of the drillstring motion is simulated by two hydraulic cylinders (2) configured to produce adjustable damping. To mimic the driving force of the bit's interaction with the well bottom, a lower assembly (7) is provided. In this assembly, a cam (8) is rotated by a variable speed gear motor (9) at rates simulating the drillstring rotation rate. The cam, which is supported by ball bearings, can have configurations that mimic a variety of degrees of irregularity of the well bottom.

Test results

Early static testing established that the AVD could provide adequate damping to support about 6,000 lbs of force. With the Belleville springs supporting the majority of the WOB, this should be adequate to provide the necessary damping in most drilling conditions.

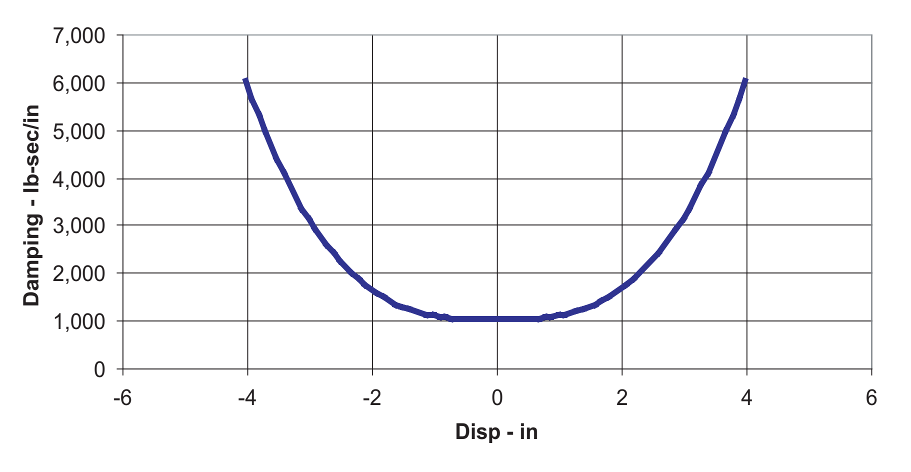

Figure 8. Active vibration damper hardening algorithm.

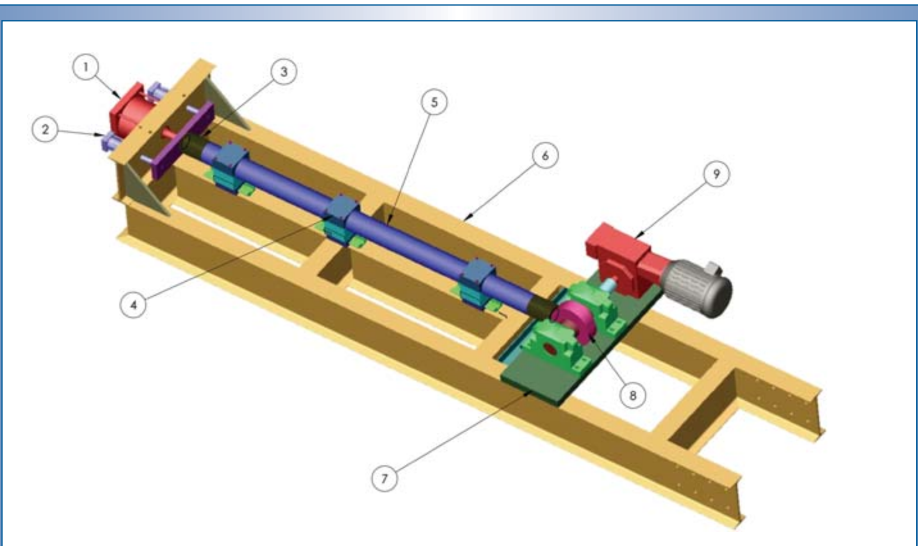

Figure 9. Active vibration test bench.

In the next phase of testing, the full laboratory prototype, including the Belleville springs and bearings, was mounted in the test bench and driven by the cam. A sample of the results is shown in Figure 10, which plots the dynamic stiffness of the AVD as a function of the current applied and the drive frequency. The dynamic stiffness of the damper is a combination of the stiffness of the springs and variable damping applied by the AVD. This combination is a function of the frequency of the driving vibration. As the applied current increases, the dynamic stiffness of the AVD rises.

The AVD can instantaneously vary its dynamic stiffness by a factor between 7 and 10, depending upon the excitation frequency. This is more than adequate to obtain the results described earlier in the article. The ability of the damper to reduce bit vibration and bounce is shown in Figure 11, which plots the maximum motion of the damper collar (connected to the bit) relative to the central mandrel, (connected to the upper drillstring. The driving displacement from the cam was 0.7. As the damping is increased by increasing the applied voltage, the maximum motion converges toward a level consistent with the bit's remaining in constant contact with the cam, which simulates the irregular bottom of the well.

Conclusions

AVD laboratory testing indicates it is amply capable of providing the variable damping necessary to control bit bounce, maintain uniform WOB and increase drilling ROP.

Once some optimization issues have been resolved, it is anticipated a prototype AVD tool will be tested, first in drilling laboratories and then in the field, later this year.

Based on the laboratory results, the AVD is likely to have a significant impact upon drilling operations, particularly in hard rock drilling. As illustrated in Figure 11, a properly damped drillstring will drill more efficiently, with fewer failures, than one without such damping. The modeling indicates the potential for increasing the average ROP by 10% to 50%, depending upon conditions.

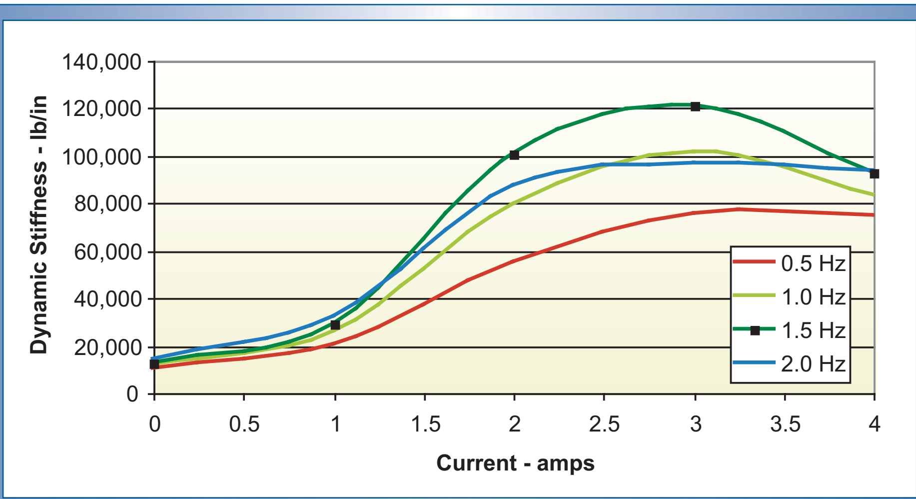

Figure 10. Dynamic stiffness of the active vibration damper as a function of current and frequency.

Future efforts

The detection and active damping of axial vibrations represents the first step in this program. There are other troublesome vibration mechanisms, such as transverse vibrations and stick-slip torsional modes. It is likely that by modulating the WOB, the AVD will reduce the likelihood of the bit's digging into the borehole bottom and initiating sticking, followed by slipping when the WOB decreases. This effect will be evaluated in the field trials.

Plans are underway to add torsional and lateral sensors, and damping to the AVD system. Initial designs have been prepared. Further studies will investigate whether the benefit from these additional features justifies the additional costs involved. ✧

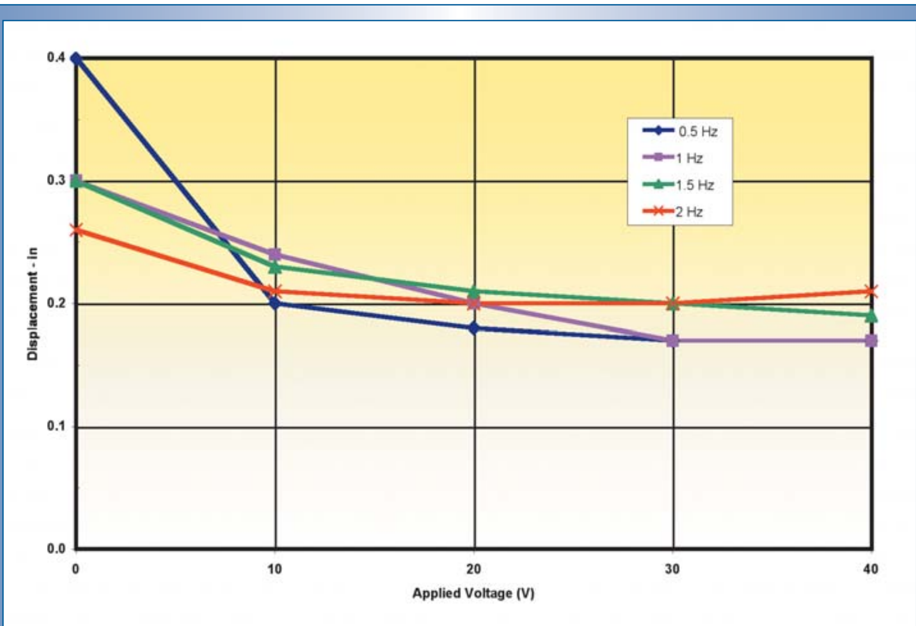

Figure 11. Maximum relative motion of the damper components during testing.

Acknowledgments

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Long-term Cement Integrity of HPHT Cement Systems

By Fred Sabins, Larry Watters and Kevin Edgley, *CSI Technologies*; and Tim Grant, *U.S. Department of Energy*

Deep Trek, a U.S. Department of Energy program, seeks to improve HPHT well economics by improving drilling and completion technology. As part of the Deep Trek effort, CSI Technologies is attempting to improve the economics of deep-well completions with the development of a "supercement" capable of providing long-term, HPHT sealing integrity.

Industry growth in the United States finds drillers moving into deeper and hotter frontiers in search of oil and gas. Remediation of failed cement jobs in deep hot wells costs the industry more than $100 million each year. While additives and well-designed placement techniques can increase chances for achieving long-term zonal isolation in high-pressure, high-temperature (HPHT) wells, a high incidence of gas pressure on deep hot wells because of inadequate placement and mechanical failure of cements, continues to be reported.

Although applications and methods may vary, Portland cements have been used worldwide and are recognized as the industry standard for well sealants. Temperature and pressures encountered through production and intervention can induce high stresses in the wellbore, exceeding the resistance capabilities of conventional Portland cement systems. Short-term fluid migration of water and gas also affects the performance of wellbore cement, and mechanical cement failure is exaggerated in wells with narrow annuli because of higher stress on the cement sheath.

With current completion technology, a supercement designed for long-term sealing integrity in HPHT wells is needed to alleviate escalating costs associated with annular seal loss and associated remedial repair. Remedial procedures for restoring seal integrity are expensive and multiple applications often are required during the well's life. Annular seal loss in HPHT wells can result in well abandonment, and potential environmental and safety issues.

Deep Trek, a U.S. Department of Energy (DOE) program, seeks to improve HPHT well economics by improving drilling and completion technology. As part of the Deep Trek effort, CSI Technologies is attempting to improve the economics of deep-well completions with the development of a supercement capable of providing long-term, HPHT sealing integrity. The material may also be applicable in less extreme environments that still require high stress resistance, or where annular gas pressure is a known problem. With tensile and compressive strength, permeability, expansive properties, and pipe and formation bonding sufficient for long-term durability, the potential for mechanical failures at temperatures exceeding 350˚F and at pressures over 15,000psi will be minimized.

Three years—Three phases

Last year, the CSI laboratory team began working on the first phase of the three-phase, 3-year Deep Trek project. Phase I began with laboratory analysis of various Portland and non-Portland materials, and admixtures in conventional and unconventional tests. Identification of compositions that provide the mechanical properties required for withstanding extreme downhole temperatures and pressures resulted. In Phase II, the team's work is continuing with scale-up testing and well trials to determine performance on a field scale. Scale-up activities include manufacturing, mixing, placement mechanics and performance in a test well. Demonstrations of the cement's performance in three to six field applications in hot deep wells and technology transfer activities will complete Phase III.

An industry advisory committee, comprised of representatives from 12 companies, has assisted in the technical development of the supercement material and continues to provide a combined expertise for project execution. Membership is voluntary and includes Anadarko, BHP Billiton, BP, ChevronTexaco, ConocoPhillips, the DOE, Dominion, McMoran, PDO, 3M, Shell and Unocal.

In Phase II, committee members will assist in monitoring and evaluating performance of the candidate supercement material(s) in actual wells. Additionally, committee members contribute data to a deep hot well database used for test design, specification development and as a technical exchange medium.

Phase I—Project objectives

Phase I, conducted from October 2003 through December 2004, concentrated on identifying state-of-the-art sealant systems, especially those applicable to HPHT environments. A baseline series of Portland cement designs commonly used in HPHT environments was identified and tested to determine currently-available performance. Various candidate systems, designed and screened at low and high temperatures, narrowed the field to a manageable number.

Finally, unconventional tests were utilized to gain insight into the sealing capability of the candidate systems. This work is in preparation of Phase II scale-up and field trial work.

General project execution

During Phase I, 169 different slurry compositions were evaluated in more than 1,100 laboratory tests. Low-temperature screening tests were abandoned for some slurries, because they were engineered for reactions at higher temperatures and would not attain strength at lower temperatures. The "base" series of testing consisted of compressive strength, compressive Young's Modulus and tensile strength utilizing the splitting tensile method (Figure 1).

Tests not routinely conducted in today's industry include flexural strength, shearbond, anelastic strain and annular seal (Figure 2). These unconventional analyses helped gain insight into the interactions between a material's mechanical properties and wellbore sealing capability. Anelastic strain is a measure of permanent deformation in cement as a result of repeated low-stress load application. This permanent deformation represents cumulative damage, leading to eventual failure at loads well below ultimate stress levels (Figure 3).

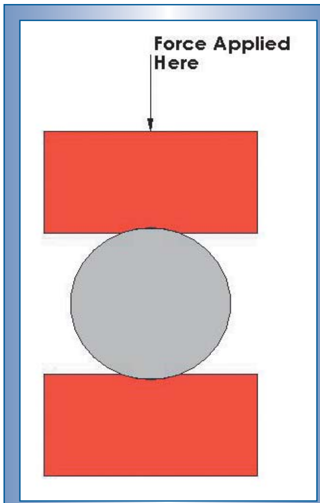

Figure 1. Splitting tensile test method (ASTM D3967-95A). Diametrically-applied force induces tensile stress in a plane normal to the load application.

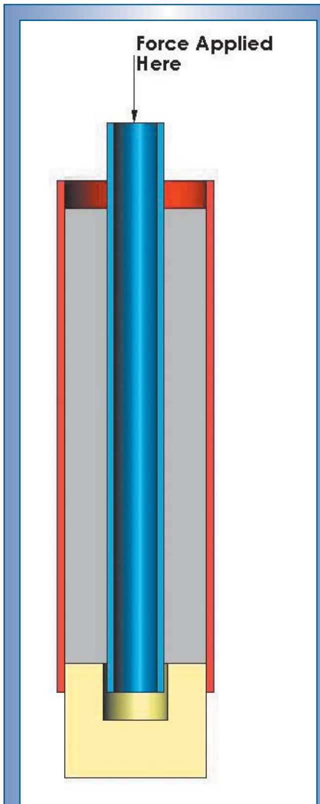

Figure 2. Measurement of the shear bond between the inner pipe and cement.

No combinations of mechanical properties, and specifically no single mechanical property, are sufficient to predict the ability of a cementing material to produce an effective and long-term annular seal in a wellbore environment. The precise nature of the interaction of the various mechanical properties of cementitious materials, in context of well failure, is yet unknown. Some correlation work has been done, but it represents a preliminary evaluation of cement properties required to form a competent annular seal in a wellbore environment.

Significant efforts were expended developing monolith production, test protocols and equipment modifications for the project. Specialized devices were designed and built to measure deformation during loading for compressive Young's Modulus, as well as for flexural test beams. The Splitting Tensile Test (ASTM D3967-95A) was chosen for tensile strength testing because of the simpler test requirements, sample productions and test procedures. A controlled-rate press was modified to allow for cycle-testing determining anelastic strain properties.

Annular seal test

The annular seal test is considered the best available predictor of a material's sealing performance in a well environment. Cement is placed in a geometrically representative test fixture with loading applied from internal pipe pressure. A cross section of the test fixture is shown in Figure 4.

The red outer tube represents the formation or outer pipe and can be varied to simulate formation of various strengths. The gray material is the cement sheath, and the blue pipe represents the wellbore tubing or casing. The yellow end piece conducts gas flow to the cement sheath. In practice, the cement is cured in the fixture. Low-pressure gas (10psi) is connected to the open end of the yellow end piece, and a source of high-pressure water is connected to the inner diameter of the blue tubing.

Water pressure is applied in successive pressure cycles in increments of 1,000psi and then released, starting at 1,000psi. When a maximum pressure of 10,000psi is reached, four more cycles of 10,000psi are applied. This sequence represents one full cycle; after which, the cycle is repeated starting at 1,000psi. The flow of gas remains at zero while the annular seal is intact. When the cement fails, a flow path opens through the cement and the gas flow rate is measured. In practice, the material mechanical properties and the interactions between the properties determine when the annular seal is compromised. Materials engineered for sealing performance at high temperatures may not set at low temperatures or may exhibit mechanical properties different from those obtained at higher temperatures. As Phase II progresses, the annular seal test is being redesigned to evaluate material properties at elevated temperatures.

Energy analysis

Cement sheaths subject to loads imposed by well conditions and intervention activities are subject to failure at some point. In the well, a strong formation and heavy pipe essentially "back up" the cement, resulting in more energy absorption before cement failure. Laboratory studies conducted in the

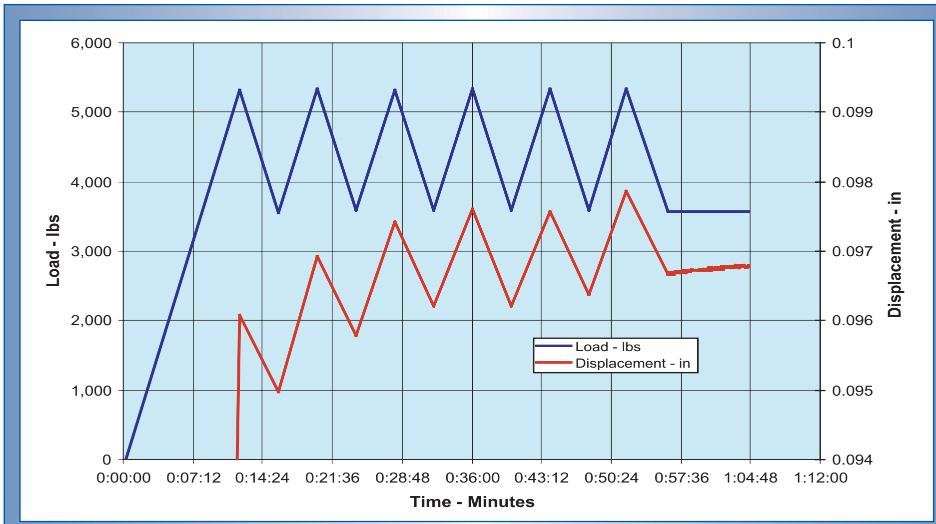

Figure 3. Measure of permanent damage (measured in permanent strain) in cement sample as a result of low-stress loading.

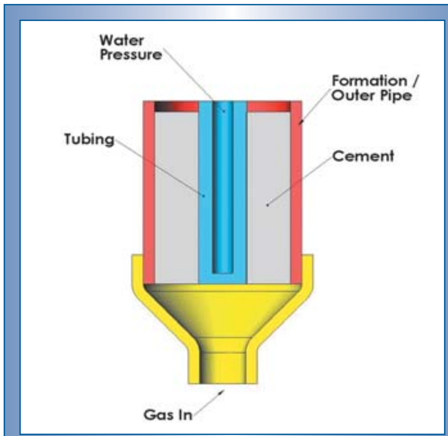

Figure 4. Measures annular seal integrity in a geometrically-representative model. Failure is related to a complex interaction of cement mechanical properties and indicated by measured gas flow.

annular seal model indicate that cement failure is related to the amount of energy imposed on the cement sheath during the life of the well. Mechanical properties of cement strength are important, but there are other cement and non-cement variables that affect long-term integrity of the cement sheath. These variables include:

- cement properties
  - cement tensile strength
  - cement Young's Modulus
  - anelastic strain
  - radius of cement sheath
- well properties
  - size and wall thickness of casings
  - hole size
  - formation Young's Modulus
- loading data
  - anticipated intervention and production loading profile

The correlation involves a dimensionless energy application factor, representing the energy applied to the cement sheath in a well; and an energy resistance factor, representing the ability of the pipe/cement/formation system to resist the applied energy. The correlation derived to date is useful but not comprehensive in terms of mechanical properties. Additional tests, using different mechanical properties and load rates, are planned.

Test compositions

Compositions tested throughout the project include:

- baseline Portland cement recipes;
- ceramicrete and its derivatives;
- reduced water systems (highly dispersed);
- high-concentration reactive and nonreactive fibers;
- Portland cement with unconventional additives; and
- non-Portland cements.

Throughout this project, material selection and chemistry efforts are based on the theory that improvement in the crystalline structure results in reducing porosity and permeability, thereby strengthening the mechanical structure of the cement and improving annular sealing performance. As shown in the table on the next page, low values are desirable for anelastic strain and annular seal test results; high values are desirable for the remainder of the reported tests.

Portland cements are comprised of a highly heterogeneous matrix in which large particles of various materials are present in a cementitious binder. These cements are relatively brittle, exhibit significant compressive strengths and relatively low tensile strengths, and bond reasonably well to steel. Heat can degrade the cement during time, and the matrix is usually porous and permeable because of the excess water required to mix and pump the material.

In Portland systems, not much can be done about the mechanically inefficient matrix structure, but decreasing the amount of water present in the slurry can reduce shrinkage and improve strength, permeability and porosity. The following strategies were utilized to affect performance improvements.

Reduced water—Reducing the amount of water present in the slurry improved strength and reduced porosity. This is straightforward cement chemistry where strength is generally proportional to the cement-to-water ratio for a given cement composition. The slurries tested with reduced water were highly dispersed to improve mixability. In common cements, highly-dispersed slurries can cause difficulties because of settling. The slurries investigated were not tested specifically for settling, but appeared to produce reasonable suspension properties for the solids due to water content reduction.

Fibers—Fibers are known to improve tensile strength, or more specifically, the toughness of cement. However, they can actually create problems by bonding mechanically to the matrix and providing fracture points when the cement is stressed. Reactive fibers, such as ceramics and silicates, were used to provide mechanical and chemical bonding properties to the matrix. Various compositions and fiber lengths were investigated. Results incorporating ceramic fibers are encouraging, and fibers are applicable to a wide range of Portland and non-Portland systems.

Unconventional additives—These include additives commonly used in cements, but in higher concentrations than typical, as well as new additives not utilized in the industry. Studies focused on molybdenum and high concentrations of magnesium oxide, both of which cause significant expansion in the cement matrix. If expansion occurs at the right time during the hydration process, it can result in a denser matrix, higher strength and lower permeability product.

Preliminary test results of candidate systems. Blue—Best properties (or nearly best). Red—Worst values in systems studied. Low values—Desirable for anelastic strain and annular seal tests. High values—Desirable for remainder of tests.

System	Formula	Compressive Strength psi	Tensile Strength psi	Anelastic Strain in/in/min	Shear Bond psi	Annular Seal Ml/min flow
Baseline	*77*	*5,650*	*730*	*44%*	*471*	*1.0*
Baseline	*99*	*4,790*	*710*	*100%*	*256*	*2.4*
MgO	*128*	*3,190*	*280*	*In Proc*	*1,850+*	*In Proc*
Moly	*132*	*4,280*	*1,080*	*25%*	*310*	*2.3*
Moly	*133*	*6,680*	*1,370*	*18%*	*570*	*3+*
Resin	*120*	*In Proc*	*2,210*	*In Proc*	*In Proc*	*In Proc*
Resin	*121*	*In Proc*	*3,200*	*In Proc*	*In Proc*	*On Proc*
Fiber	*130*	*3,710*	*1,020*	*52%*	*299*	*0*
Fiber	*131*	*3,020*	*1,150*	*54%*	*186*	*0.6*
Fiber	*136*	*4,510*	*1,310*	*31%*	*1,021*	*In Proc*
Ca Al Silicate	*169*	*1,920*	*220*	*In Proc*	*In Proc*	*In Proc*

Timing is critical during the hydration process; if expansion occurs too early or too late, it can lead to matrix disintegration. When cured under confined conditions, where dimensional expansion is restricted, the expansion is theoretically directed inward to the matrix, thereby reducing porosity and permeability. In practice, this method has led to high shear bonds, although both compressive and tensile strengths of cored samples have been modest. Annular seal tests are planned to determine the ultimate potential of the material.

Non-Portland systems—Initial research focused on ceramicrete and other acid-base systems, but produced insufficient results for inclusion in Phase II. Other systems included a calcium-aluminum-silicate mix and a high-temperature resin.

A range of calcium aluminum silicate, calcium aluminum phosphate and magnesium aluminum phosphate systems were screened for strength development at 350°F. Although results were unexceptional, work in this area was incomplete at the end of Phase 1. Testing with a CAS system varying slurry density and component ratios is continuing during Phase II, and initial results are encouraging.

The high-temperature resin produced high tensile strengths, which were as much as 10 times higher than those of conventional Portland cements. Typically, resins soften with temperature, making them of dubious value in high-temperature wells. The resin under consideration has been formulated to retain properties at elevated temperatures, thereby qualifying the material as a candidate for this project. The high elasticity exhibited by the material may be useful in attaining long-term sealing integrity; other property testing is incomplete.

A full-scale mixing test yielded the following difficulties with handling the resin on a large scale in an oilfield cementing environment:

- vapors pose possible health risks;
- surface mixing consists of mixing the liquid resin with a liquid activator in precise relative quantities;
- air and water entrainment causes a persistent entrainment issue in the mixing tub, which can cause problems if density measurements are required during mixing;
- resin chemistry is a highly exothermic reaction, creating high temperatures that can damage mixing equipment and pose a health risk to personnel;
- resin can be weighted or lightened for placement efficiencies. The limits of weighting and the impact on material performance are unknown;
- resin does not mix with water, which may generate advantages or disadvantages. Issues include displacement mechanics, mixing requirements, and sweep efficiency for mud and spacer removal; and
- mixing on a field scale will require the development of specialized equipment with sealed containers, precise rate control and dedicated pumps. The heat-activated nature of the material may make it difficult to place the material in the HPHT well environment. Cleanup procedures and disposal of cleanup materials must be addressed.

Conclusions

The first year of this Deep Trek-related project has generated new insights and theories into the mechanisms by which cement mechanical properties translate to annular sealing performance in oil and gas wells. Test protocol and analysis methods have been developed to better understand cement performance, and a suite of materials has been identified for evaluation in scale-up field trials. Ultimate improvements in HPHT well economics will result with the successful development of an HPHT supercement. ✧

Capturing Missed Reserves in Existing Wells

By Tom Engler,
New Mexico Tech

The motivation behind capturing the missed reserves is the geologic complexity of the reservoirs, such as sequences of low-permeability sands and shales, existence of natural fractures and variable reservoir architecture caused by abrupt changes in stratigraphic facies.

The infill drilling approach is reasonable and has been successfully demonstrated in many basins. As a result of this development and advances in technology, new and additional pay zones are identified and exploited. However, the transfer of this knowledge to already existing wells is frequently overlooked. A research project funded by RPSEA investigated how to better define and effectively stimulate behind-pipe pay zones in existing wellbores in tight-gas sand sequences. The need in "existing wells" is driven by the request of independents and reflects the preference to optimize existing wells over capital expenditures for new development. In this article, only stimulation aspects of behind-pipe zones are discussed, however the entire report is available from the Gas Technology Institute.

The San Juan Basin, roughly circular in shape (Figure 1), is an asymmetrical syncline in northwestern New Mexico and southwestern Colorado. The selected target for this research is the Menefee Formation of the prolific Mesaverde Group in the San Juan Basin.

The Mesaverde is divided into a basal unit, the Point Lookout Sandstone, a relatively uniform blanket-type, low-permeability sandstone formation; the Menefee Formation, overlying the Point Lookout, a sequence of coals, sands and shales; and the Cliff House formation, which is similar in reservoir characteristics to the Point Lookout, but less extensive.

Production/development history

The Blanco Mesaverde Pool in the San Juan Basin was discovered in 1927 and has grown in response to pipeline capacity, decreased well spacing and price increases. Extensive development occur-red in the 1950s on 320-acre spacing when the Western gas market became available. Since then, the spacing has been reduced twice, to 160-acres per well in 1975 and to 80-acre spacing in 1998. Cumulative production to date is greater than 10 Tcf, with an estimate of 7 Tcf of additional proven reserves. At this time, more than 4,900 completions yield a total of 0.75 Bcf/d. It is expected that within the next 20 years, about 4,300 additional completions will occur, many of which will be dual completions with the deeper Dakota Sandstone.

Traditionally, the focus of most operators was to concentrate efforts on the clean, relatively thick and laterally extensive Point Lookout and Cliff House Sandstones, ignoring the Menefee Formation between the two. This underdevelopment of the Menefee is because of the lenticular nature of the reservoirs and difficulty of evaluating the reservoirs using geophysical logs.

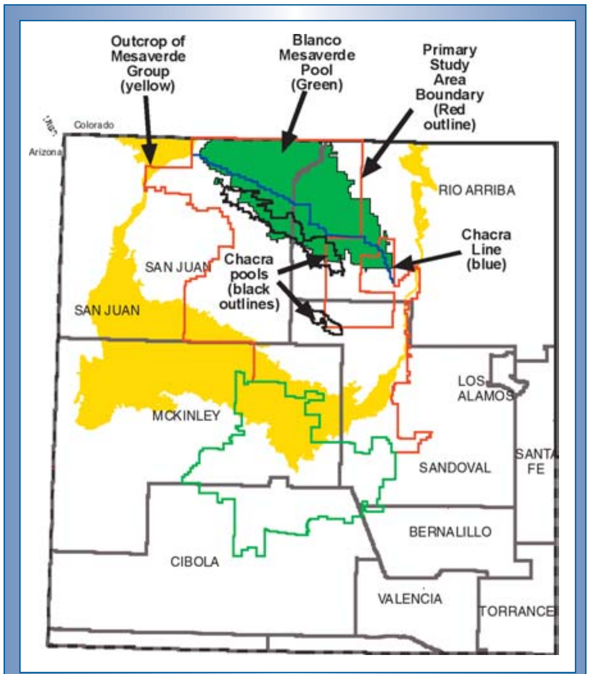

Figure 1. The map of New Mexico portion of San Juan Basin shows a Mesaverde Group outcrop, Blanco Mesaverde pool, Chacra line and Chacra pools. (RFD, FFO, U.S. BLM, 2001)

Stimulation

In response to the low permeability of these types of reservoirs, stimulation (particularly hydraulic fracturing) is required to develop a commercial well. Typically, this stimulation is done during the initial completion of a well. The addition of "behind-pipe" pay leads to a variety of problems in designing an effective stimulation treatment. Using the Menefee as our example, the lenticular and discontinuous nature of the embedded sands can lead to complex fracture geometries; exacerbated by the reduced net effective stress because of partially-depleted layers above and below the Menefee. The mechanics of fracturing are subject to maximum allowable pump rate and pressure for older wells, casing or tubing size and integrity, and avoiding re-fracing old perforated zones in an attempt to stimulate only the new, "bypassed" pay zone.

To assess the Menefee contribution to overall well performance and the impact stimulation plays on this performance, the approach was to:

- analyze the production performance of Menefee pay-adds. As mentioned previously, in many cases the Menefee has been bypassed as a potential reservoir because of its poor reservoir characteristics;
- compare production performance from wells completed with and without the Menefee, both original parent-type wells and daughter wells, in a selected region; and
- compare and discuss the effectiveness of the various stimulation treatments.

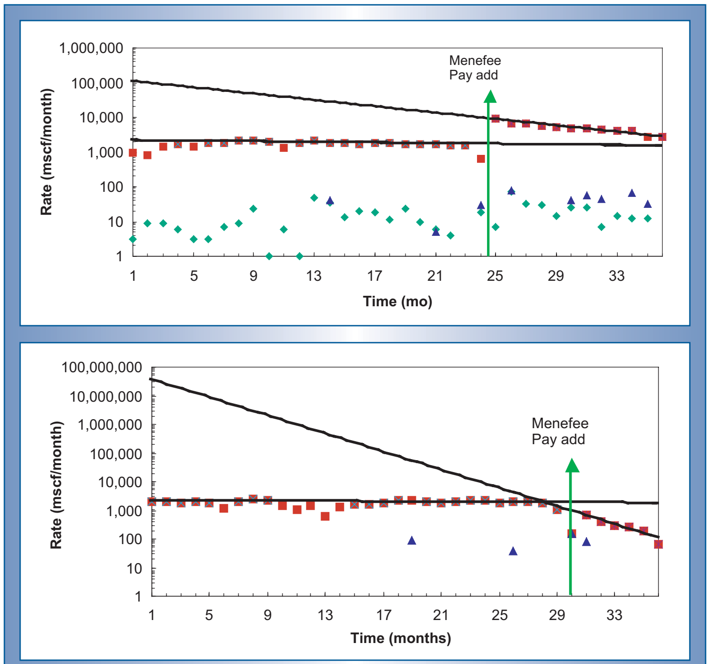

Figure 2 Two examples of Menefee pay add wells. Success (a) and failure (b). (Gas—red squares, oil—green diamonds, water—blue triangles)

Menefee payadd refers to a remedial workover where the Menefee Formation is completed and stimulated within an existing wellbore. The success of these workovers can be evaluated by the difference between the before and after production, or the incremental reserves developed by adding the Menefee. A subset of more than 40 wells was identified as Menefee payadds, geographically located across a wide area within the San Juan Basin. This remedial work began in 2002.

Two examples are shown in Figure 2. The first production curve represents the best well, resulting in first year incremental production of 63 MMscf. The second production curve illustrates an unsuccessful payadd with poor production response, with after workover production less than the previous rate.

Overall, an estimated incremental ultimate recovery of 1.7 Bscf of gas can be attributed to the 40-well, Menefee program. Of the 40 wells, production performance after the workover of four wells was initially less than the prior rate. These wells have continued this poor trend and therefore are deemed failures. The remaining wells are estimated to average 46 MMscf of incremental gas per well, to be retrieved during a 2-year span. The best well will incrementally produce 285 MMscf.

To further distinguish the Menefee contribution, production performance was compared among four types of wells; old wells (originally completed between the late 1950s and early 1960s) with Menefee, old wells without Menefee, wells completed in the 1980s and those with recent (about 1998) well development. Several important factors that play a role in the variation of performance must be considered:

- the change in completion effectiveness with time. Tech-nological advances promote the idea of improved hyd-raulic fracture performance;
- pressure depletion of the Cliffhouse and Point Lookout Formations. A new well may add gas reserves from Menefee, but may recover less reserves from the Cliffhouse or Point Lookout because of previous pressure depletion. All producing zones are commingled in the wellbore;
- changing surface and/or market constraints. Gas-gathering line pressures have been reduced in the San Juan Basin, resulting in longer production life and reserves. The addition of compression will have the same impact. In the past, a proration system was in effect reflecting market conditions; and
- variations in flow and storage capacity from well to well because of the discontinuous nature of the formations.

The target area to be evaluated was on the east side of the basin where data for more than 75 new well completions was collected and analyzed along with 30 original and 1980s wells, all within the same geographic area.

Results from this analysis are displayed in Figure 3 as cumulative production curves. The time scale has been shifted so each series begins at time zero, even though the actual date of initial production is different. These curves represent average production per well for each designated group. The comparison between the original wells with and without the Menefee has the advantage of minimizing the impact of the four factors previously described. Inspection of the curves for the original wells shows that adding the Menefee increases incremental per well cumulative production by 103 MMscf.

Figure 3 shows the average cumulative production for wells completed in the early 1980s. Note the identical trend of this group of wells and the previous original, with Menefee group. This behavior implies:

- flow and storage capacity are reasonably consistent throughout the study area, not an unreasonable assumption since new wells are between existing development wells;
- completion methods are similar and provide no improvement in effectiveness;
- surface and market constraints are similar for both groups of wells. This is possibly true in this portion of the basin but not scaleable to the entire basin; and

- pressure depletion has been minimal in the Cliffhouse and Point Lookout Formations. Recent pressure transient tests on infill wells have confirmed the lack of pressure depletion.

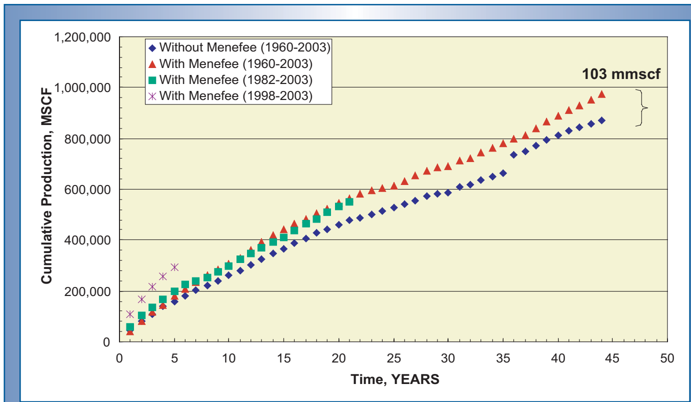

Figure 3. Average cumulative production for wells (with and without the Menefee contributing) as a function of date of completion.

A final comparison shown in Figure 3 is the recent wells drilled since 1998. These wells are composed primarily of 160-acre development wells, all of which included the Menefee in the original completions. Results indicate a substantial improvement of well performance during the first 6-year life of these wells. In this case, improved performance for new wells could reflect advances in stimulation technology, more favorable market/surface conditions or increased contributions from the Menefee. A decreased performance for the new wells could result from pressure depletion of the Cliff House and Point Lookout Formations. In both instances, variations of storage and flow capacities are assumed constant.

A final area of interest is to compare stimulation methods and effectiveness. A cursory review of stimulation methods was undertaken to identify whether any specific treatment was more effective than another treatment.

Early (1950s to 1960s) completions consisted of "block" perforating with two shots/ft or greater, and then hydraulically fracturing down casing with slick water only or water and sand combined. By the early 1980s, wells were selectively perforated with 20 to 40 holes over the Mesaverde section. Stimulation consisted of a small near-wellbore, acid cleanup followed by 80,000 gal of water with 80,000 lb of 20/40 sand, also pumped down the casing. The 1998 wells were completed almost exclusively by selective perforating and fracture treating down casing with slick water and 80,000 lb of 20/40 sand, in two stages. The first stage treated the Point Lookout only, while the second stage combined the Menefee and Cliffhouse.

In summary this work does not reveal the specific advances in fracture technology with time such as cleaner frac fluids, improved additives or proppants. However, several general observations can be made:

- stimulation type was consistent throughout any given time period. Only minor fluctuations in volumes and method occurred in the study group, and there is no difference in stimulation between wells with or without the Menefee. Stimulation is not the reason for the incremental production shown in Figure 3, but is a result of the Menefee pay included in the well;
- the slight variation of completions in the early 1980s appears to have little impact on improving well performance. As shown in Figure 3, the cumulative production curve is identical to the one between 1960 and 1983, with Menefee curve; and
- well performance for the 1998 well group has been significantly better than its predecessors. This could be the result of improved stimulation effectiveness, in which case, acceleration of production may be dominant. Alternatively, better quality of Menefee pay also would lead to the addition of reserves.

The Menefee payadd wells were all selectively perforated and then hydraulically fractured down tubing with a 70-quality nitrogen foam and about 70,000 lb of 16/30 sand. Pump rate and allowable pressure restrictions were encountered by treating through tubing instead of casing. This requirement is because of the existing Cliff House perforations above the Menefee, thus limiting the stimulation options available.

Summary

Key factors influencing performance are:

- variations in completion practices from well to well with time;
- pressure depletion of the Cliffhouse and Point Lookout Formations;
- changing surface and/or market constraints; and
- variations in flow and storage capacity from well to well.

Differentiation of the impact of each individual factor was not attempted; however, several general observations are apparent from this initial work:

- the Menefee adds incremental reserves to the production stream. This work demonstrated better recovery (103 MMscf) when the Menefee is included in the initial completion than when added later (46 MMscf) as a remedial workover;
- the payadd stimulation is constrained by the existing Cliff House completion above the Menefee target. Consequently, stimulation effectiveness is reduced;
- the latest stimulation practices appear to be successful, resulting in improved well performance; and
- the best payadd candidate resulted in 285 MMscf of incremental reserves. This potential confirms the need for improved reservoir description to identify the best targets to add Menefee and to avoid those areas that do not exhibit potential. ✧

A High-flying Alternative to Walking the Line

By Steven Stearns,
ITT Industries, Space Systems Division

More than 2,000 years ago, natural gas was sent across Tibet via bamboo pipes. How did they maintain the integrity of that system? By walking the line. For as long as there have been natural gas pipelines, inspectors have had no choice but to walk the line to detect leaks and ensure public safety. Now the endless walk is over.

ITT Industries has introduced a breakthrough airborne technology that makes it possible to inspect pipelines up to 100 times faster and provides 30 times more right-of-way (ROW) coverage than traditional methods. The Airborne Natural Gas Emission Lidar (ANGEL) Service detects and quantifies leaks with a high degree of accuracy. It also surveys, maps and images pipeline corridors and surrounding areas then delivers detailed GIS-ready datasets and reports. And it does it all, day or night – more than 1,000 miles a day.

Because it's airborne, the ANGEL Service doesn't have to deal with obstacles that often slow down ground crews. Issues such as difficult terrain, property access, inclement weather and insufficient field staff are a thing of the past. The ANGEL Service also can be used in known dangerous areas without having to put people in harms way. Perhaps best of all, the ANGEL Service is a cost-effective, end-to-end, out-sourced service. By subscribing to the ANGEL Service, natural gas providers not only obtain necessary information required to meet today's enhanced regulatory compliance, but also detailed information that will benefit various departments within their company including pipeline integrity management (PIM); geomatics (GIS); environment, health and safety (EHS); and operations and maintenance (O&M).

While the technologies used by the ANGEL Service (differential absorption LIDAR, aerial mapping and surveying, and differential global positioning system (GPS) to name just a few) may be new to some in the natural gas industry, they have been in use for many years in different applications ranging from cartography to environmental monitoring. ITT is knowledgeable in these technologies, as they have been developing innovative remote sensing technologies for defense, intelligence and aerospace applications for more than 50 years. ITT remote sensing technology is used everyday in weather and imaging satellites, space telescopes and GPS systems to collect information and images of earth and space.

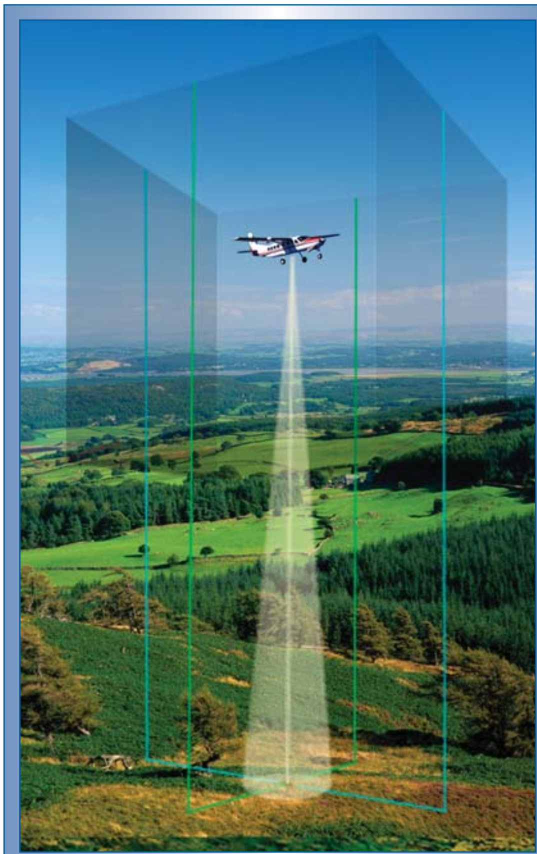

Figure 1. Conceptual view of the ANGEL aircraft capturing survey data along pipeline right-of-way.

ANGEL Service operations

When a company subscribes to the ANGEL Service, they're buying a turnkey service from a Fortune 500 company that is a worldwide leader in the remote sensing sciences. ITT handles every detail of the logistics, including all aircraft operations, data collection and processing, and report generation.

The ANGEL Service provides an instrumented leak survey using a remote sensing system built on differential absorption lidar (DIAL), an extremely sensitive gas detection and quantification technology. Installed aboard a Cessna Grand Caravan 208B aircraft, the ANGEL system collects up to 180,000 laser measurements per minute while flying at 1,500ft above the ground at 120 mph. That means it's sensitive, thorough, efficient and accurate. The ANGEL system scans the pipeline corridor, remotely sensing ethane and methane emissions. It then precisely images and maps the plume's physical size and ground location allowing the client to fully understand the situation before responding.

To ensure targeting accuracy and pipeline coverage, the ANGEL system features a computer-guided laser pointing and tracking sub-system. It scans a 100-ft wide ground track along the pipeline ROW. This wide coverage area increases the likelihood of

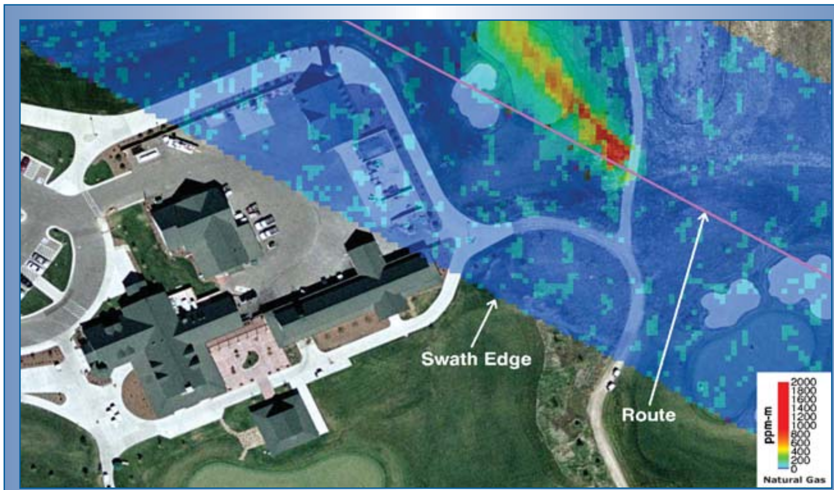

Figure 2. Ten-time enlargement of natural gas plume. ITT ANGEL system has detected emissions of natural gas. The plume is integrated with color imagery and GIS coordinated to provide the precise location.

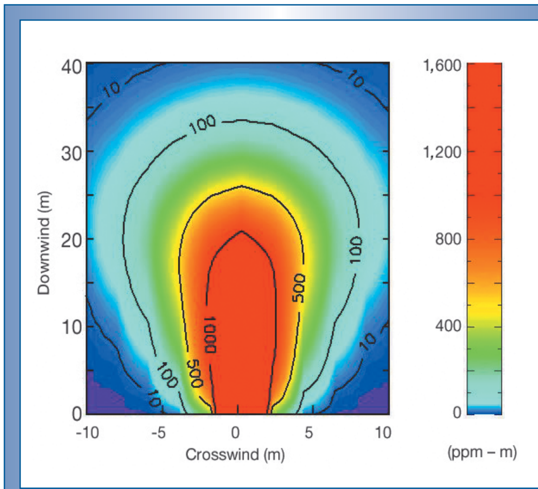

Figure 3. The ANGEL system detects, quantifies, images and maps gas concentrations of methane and ethane gas.

detecting leaks, even those that might have migrated away from the pipe.

At the same time, the ANGEL system captures color high-resolution orthorectified digital imagery of the entire ROW and surrounding areas. These GIS datasets can be overlaid with maps and other database information. Information can be extracted from this imagery such as high consequence area identification and third-party encroachment. It can also be seamlessly integrated into a client's existing digital geomatics and integrity management systems.

Unparalleled high-level output

After the flight, the ANGEL ground team processes and analyzes the datasets providing unparalleled high-level output and reports.

ITT provides certified findings in the form of written reports plus GIS vector layers, orthorectified color imagery and a video log of the flight. These detailed reports offer ITT's clients a range of capabilities.

These reports make it possible to respond quickly and effectively when leaks occur or pipeline integrity has been compromised. In addition, the data contained in reports provides an overview of pipeline ROW condition that makes it easier to plan maintenance.

If a client is researching the purchase or sale of a transmission system, the ANGEL Service can produce better-informed decisions during due diligence. Records can be archived and accessed as needed. Using digital maps and databases, viewers in remote locations can call up an accurate model, a virtual "big picture" of the pipeline's status. Finally, the digital record of the ROW makes it possible to fly identical missions to compare past data with the current status of the pipeline.

With 100 times the speed and 30 times the ROW coverage compared with traditional methods, the ANGEL Service is a leap forward for leak survey. The addition of current mapping imagery and videography makes for a complete service that will address the growing needs of many diverse departments within a company.

Factor in the ability to accurately collect a range of valuable data, minimize transmission downtime and ensure public safety, do it all cost effectively via an end-to-end turnkey service from ITT, and it's no wonder the ANGEL Service is gaining wide acceptance in the industry. ✧

Acknowledgements
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For more information on the ANGEL Service, or to schedule a site visit, contact:
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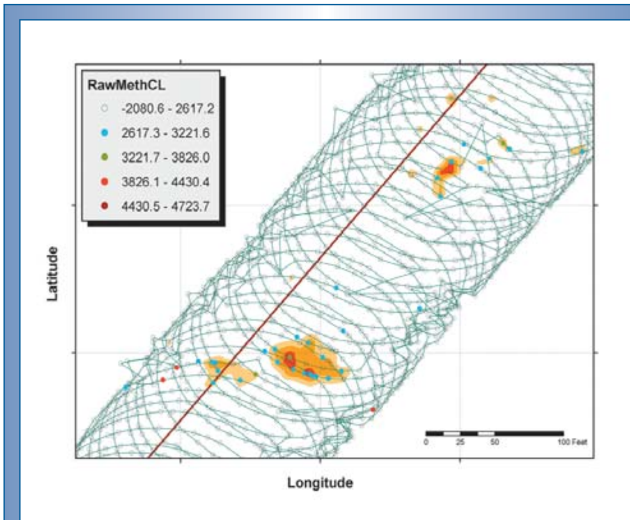

Figure 4. The conical scan display shows points color-coded to reflect the measured concentration wavelength values for methane and ethane.

Publications

▶ Heavy Oil Potential Key to Alaskan North Slope Oil Future

Alaska's North Slope boasts a massive heavy oil resource that someday could underpin the survival of one of the nation's most critical oil-producing provinces – and research funded by the U.S. Department of Energy may provide the key to unlocking this vast but, to date, largely intractable oil resource. North Slope operators have had some success producing the less-viscous crudes in the West Sak and Schrader Bluff formations by injecting slugs of water alternating with gas (WAG) into the reservoirs; the gas acts as a solvent to reduce oil viscosity, while the water front helps sweep the reservoir, pushing the crude to producing wells. Research by the University of Houston has developed tools for modeling the optimum WAG flood design. The goal of the research was to focus on modeling tools that would determine the best solvent, injection schedule, and well architecture for a WAG process in North Slope shallow-sand viscous oil reservoirs. *www.netl.doe.gov/scngo/index.html*

Events

▶ AAPG Eastern Meeting

Sept. 18-20, Morgantown, W. Va. For more information visit: *www.wvgs.wvnet.edu/www/esaapg05/*

▶ AAPG Rocky Mountain Meeting

Sept. 24-26, Jackson, Wyo. For more information visit: *www.spe.org*

Briefs

▶ "Stripper Well" Technologies Hold Promise to Boost Domestic Oil and Gas Production

Joint ventures in technology development by government and industry have delivered six new deployment-ready applications in 4 years to extend the useful life of more than 650,000 stripper wells that deliver almost 15% of America's domestic oil production and almost 8% of natural gas production, according to a U.S. Department of Energy (DOE) review.

The technologies were developed by the Stripper Well Consortium, an industry-directed group whose research, development and demonstration efforts are co-funded by the DOE through the National Energy Technology Laboratory's Strategic Center for Natural Gas and Oil. The six new technologies that have been commercialized, or are near commercialization, generally serve the purposes of increasing production, raising efficiencies or lowering costs. The consortium has been active in bringing along more than 55 additional technologies, some of which are approaching commercial readiness. *www.netl.doe.gov/publications/press/2005/tl_stripper_well.html*

▶ Energy Department Moves Forward on Alaska Natural Gas Pipeline Loan Guarantee Program

The Department of Energy published a notice of inquiry in the *Federal Register* seeking public comment on an $18 billion loan guarantee program to encourage construction of a pipeline that will bring Alaskan natural gas to the continental United States. The pipeline will provide access to Alaska's 35-Tcf of proven natural gas reserves and would be a step forward in meeting America's growing energy needs and reducing our dependence on foreign sources of energy. It would also fulfill the Bush Administration's policy to bring Alaska's natural gas reserves to market. For more information visit *www.fossil.energy.gov/news/techlines/2005/tl_pipeline_noi.html*

▶ Detection System can Help Find Pipeline Leaks, Damage

A new, lightweight device that uses natural gas to detect leaks in natural gas pipelines has been successfully tested on a transmission main owned and operated by Dominion Transmission Inc. in Morgantown, W. Va.

The test was conducted by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) and West Virginia University, which has worked with NETL for the past 2 years to advance the detection system. The device is one of a suite of technologies being developed by the Energy Department's Office of Fossil Energy to effectively and efficiently monitor the 1.3 million miles of transmission and distribution pipelines that criss-cross the United States.

Known as the Portable Acoustic Monitor Package, the device – 14-in. long, 18-in. tall and weighing 5 lb – uses a variety of tools to capture and record sound waves transmitted by natural gas. Computer software included in the package analyzes and interprets the recorded signals to detect possible leaks. Natural gas compressor stations, which pump gas from one station to another, have a distinct sound, as does natural gas flowing normally through fittings and valves. Variations to these and other background sounds alert operators that a leak may exist. *www.netl.doe.gov/publications/press/2005/tl_acoustic_monitor.html*

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