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Arrays Provide Key Reservoir Insights

By Bill Bartling

BREA, CA.–High-definition 3-D bore hole seismic imaging is acquired by deploying long, tightly spaced geophone arrays into wells surrounded by a large, dense array of seismic sources. The technique employs up to 400 three-component sensors precisely and accurately placed in the well bore to record high-fidelity, broadband, high-frequency and high-resolution seismic volumes of the surrounding reservoirs. In most cases, these high-definition volumes provide sufficient areal coverage to illuminate many step-out locations, allowing operators to precisely target variations in porosity, saturation, fracturing or enhanced oil recovery flooding progress.

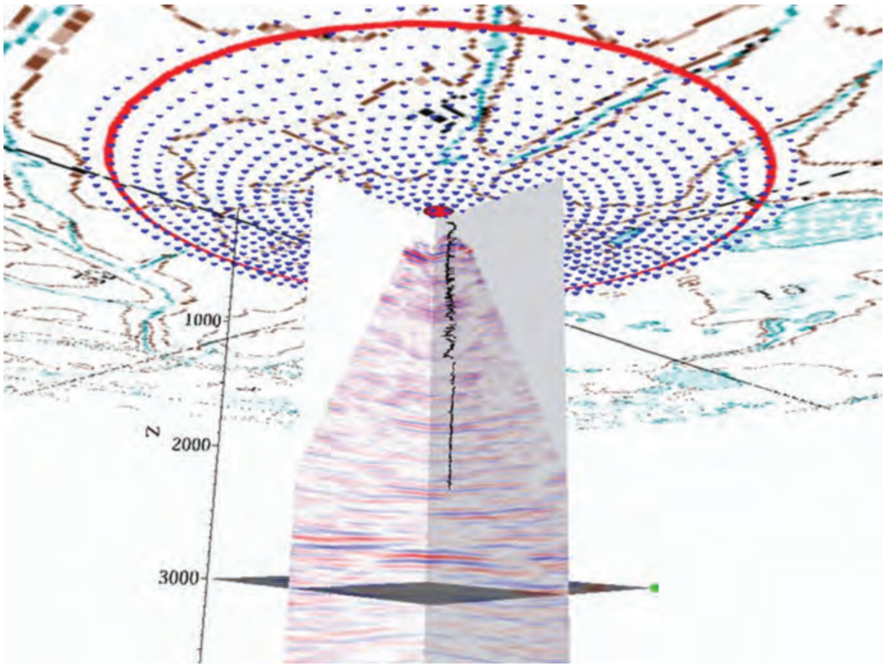
High-definition 3-D bore hole imaging takes advantage of proven seismic sensor technologies and builds on early efforts in zero-offset vertical seismic profiles (VSP) or high-density check-shot surveys. While these early efforts recorded critical data as an aid in processing surface seismic, high-definition bore hole sensors fully image the surrounding geology and reservoir conditions while also providing critical information for processing surface seismic data difficult or impossible to otherwise obtain, such as high-resolution velocity variation, near-well-bore heterogeneity, and seismic attenuation.

In concert with surface seismic, high-definition bore hole 3-D augments the regional picture by adding an asset management-focused reservoir view. In contrast to routine 2-D walkaway VSPs, the technology enables 3-D depth imaging, effectively correcting 3-D effects inherently unresolved in 2-D recordings.

In recent years, high-definition bore hole seismic has been extended to time-lapse 4-D, especially for mapping the propagation of steam and carbon dioxide EOR drives, and more recently, for monitoring, measuring, verifying and accounting for sequestered CO_2. Because of the precise repeatability of geophone depth positioning–especially using tubing- or drill pipe-deployed arrays–very high resolution and high precision difference volumes can be generated to map the detailed effectiveness of the injection programs, thereby optimizing their cost-benefit.

Compared with alternative monitoring methods, such as repeat logging or 4-D surface seismic, high-definition bore hole 3-D delivers much greater depth of penetration than well logs (thousands rather than tens of feet) and up to five times the resolution of surface seismic. While bore hole arrays provide less lateral coverage than surface seismic (the diameter of coverage around the well is approximately equal to the depth of the well), the surveys are easily overlapped and combined in data processing to create progressively larger high-resolution reservoir volumes.

Consequently, an operator can acquire bore hole surveys "just in time" according to the reservoir management plan, and because turnaround time for processed results is a matter of weeks, interpreters will have exactly the right data, at exactly the right time for critical reservoir man-



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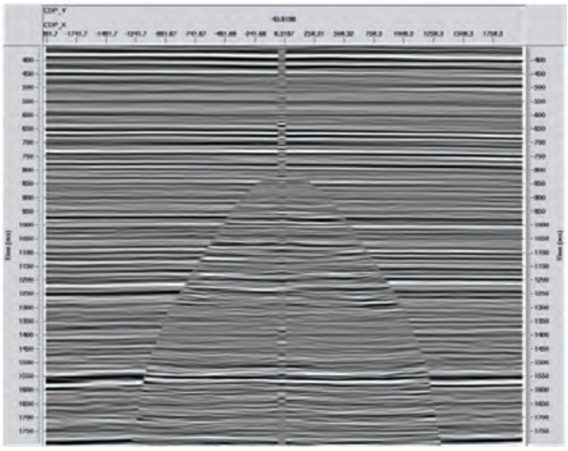


With rapid-turnaround times, high-definition bore hole data can be acquired on a just-in-time basis to give operators crucial information to better manage reservoirs and optimize drilling, completion and production programs.

agement decisions. As an added benefit, the data volumes are much smaller than a fieldwide 3-D surface shoot, making a typical high-definition bore hole 3-D survey affordable enough to add to well authorizations for expenditure.

Detecting Fractures

The emphasis on unconventional gas from organic shales has spurred strong interest in monitoring the propagation of induced fractures and mapping natural fractures. Near-well-bore natural fractures are easily mapped using well established logging techniques such as formation microscanners or dipole sonic devices, but understanding how these persist away from the well bore using these tools can only be done by extrapolating trends. Mapping and monitoring of induced fractures is even more problematic because it is typically impractical to use these open-hole logging devices to determine their presence and attitude.

Remote sensing approaches such as tiltmeters and microseismic monitoring respectively measure subtle alterations to the earth's surface as the fracturing rocks are dilated, or the very small (but detectable) seismic waves that are generated as rocks fracture. Experience has shown that while these methods indeed record a response correlative to the hydrofrac event, their level of spatial uncertainty makes it difficult to accurately determine fracture locations in the target reservoir rocks.

In the case of microseismic monitoring, the derived position and propagation of the fracture is highly dependent on the seismic velocity–and the variations in the velocity–of the strata between the fracture and the microseismic sensor. A strong advantage of both tiltmeter and microseismic monitoring, however, is that results are delivered in real or near-real time to the operator. In many cases, the value in the speed of delivery offsets any shortcomings that may come from spatial inaccuracies.

High-definition bore hole imaging is an alternate method for determining the position and orientation of both natural and induced fractures by directly mapping the variations in compressional- and shear-wave velocities in the volume of investigation around the bore hole. As noted, a foundational measurement for this method is high-resolution velocity information (derived from P-wave direct arrivals between source and bore hole geophones) that allows precise calculation of variations in detectable rock and fluid characteristics within the 3-D volume, such as fractures.

In contrast to microseismic, this is not a real-time method because of the complexity of accurately characterizing the velocity, but results can be delivered within a few weeks. Some operators have suggested that a hybrid approach of high-definition bore hole 3-D coupled with microseismic may prove effective by running the bore hole seismic arrays prior to fracturing to provide accurate velocities that will minimize uncertainty in the results derived from microseismic.

Bore Hole Seismic Arrays

The highest resolution and maximum lateral measurements away from the well are achieved using very long antennas with optimally spaced bore hole receivers and high-density source configurations. Optimizing all these variables can be determined through presurvey modeling, customizing each survey to the specifics of the reservoir and needs of the operator. But generally speaking, shortening the antenna or decreasing the number of receivers decreases the breadth of the final image and reduces the final resolution of the volume.

Two bore hole array solutions dominate the market today. One is digital and deployed on wireline, while the other is analog and deployed on production tubing. While wireline offers faster deployment, it has less depth accuracy so the location repeatability of the receivers and sampling rates are limited by multiplexing the data into a single cable data transmission system, especially for high sensor count arrays (which are desirable for the highest-resolution recordings).

Analog systems require longer deployment times and using a production rig, but offer precision depth placement and full wave form recording that can be sampled during processing at an appropriate density to address the desired frequency content and bandwidth of the final image (typically four to eight times denser data sampling than from wireline).

Errors in location repeatability are most problematic in time-lapse surveys where measurements of changes in reservoir fluid distribution are desired. If sensor depths are significantly different in the repeat survey, the ray paths of the recorded seismic waves will be different and will sample different lithologies along with any changes in reservoir fluids.

If there is significant lithological heterogeneity–such as in fractured reservoirs or channelized clastic environments–simple difference plots may contain multiple changing variables rather than the desired single variable of fluid content. Sorting out which changes are related to sampling different lithologies in the reservoir and which are actual changes in fluid distributions may not be straightforward and can complicate incorporating the result into reservoir management plans.

Improving Recovery Rates

It is estimated that two-thirds of reserve additions in coming decades will come from improved reservoir recovery rather than exploration. Coupled with price volatility and weakness in natural gas commodity pricing, the ability to minimize finding and lifting costs underlies the economics for increasingly expensive drilling. Improved reservoir characterization is mandatory, and employing tools that provide highest resolution imagery will underpin achieving that result.

Rapid-turnaround, high-definition bore hole data give the operator information relevant to both well completion and operation, and data from which sound reservoir management planning can be made–all delivered in time to make a difference to the operation. Accelerating revenue generated from decisions made from these data up to one year faster compared with surface seismic positively affects cash flow and resulting economics for the reservoir. Adding new high-definition bore hole surveys where needed and just in time to manage the expansion of the production drilling program is a highly cost effective and reservoir management-focused alternative to surface recorded 3-D surveys.

In the long run, by employing high-definition bore hole technology in a progressive approach (overlapping surveys), the operator only buys the data needed to manage the reservoir, and pays for them over the life of the drilling program rather than all up front. This, in essence, is analogous to running well logs to add another data point to the mapping, except that bore hole imaging adds significant additional distance around the well bore beyond what well logs can measure. And the higher resolution inherent to the technology delivers resolution relevant to managing reservoirs that is lacking in surface recorded 3-D seismic.

Geometrically simple and stratigraphically homogeneous reservoirs are rare, and most of those that have been assumed to possess "tank like" characteristics when discovered have proven to be much more heterogeneous and complex as the reservoirs have been developed. Production results, pressure monitoring and infill drilling often illuminate reservoir complexities that ultimately reduce recovery, accelerate declines and increase the lifetime finding and lifting costs of the reserves compared with the reservoir plan. This can be related to a multitude of factors, but complex reservoir compartmentalization caused by undetected faulting or reservoir edges can place new wells in compartments already being drained or leave other reserves bypassed.

As producing fields age and reservoir management progresses to secondary or tertiary recovery, these errors in reservoir understanding are compounded when injected fluids do not produce the optimum effects on reserve recovery, often adding significant unnecessary cost to the operation. Understanding the details of these heterogeneities helps minimize operating costs, and high-resolution imaging is the most effective avenue to achieving this understanding. Just as a surgeon invokes a scanning device with the capacity to resolve at a level of detail necessary to perform an intricate surgical procedure, the reservoir manager should solicit technologies that can scan the subsurface at the scale that affects its performance.

The Business Case

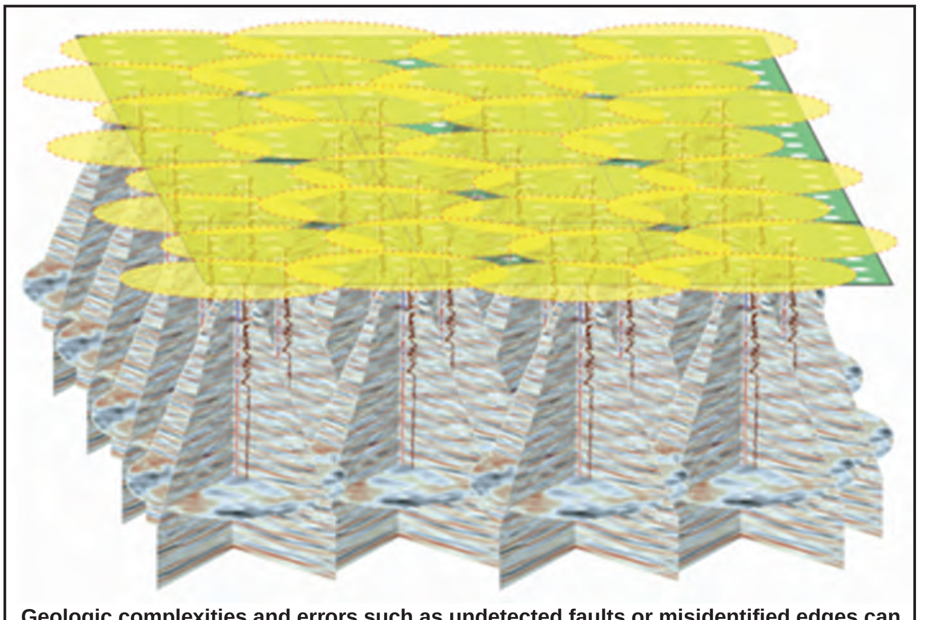
The barriers to high-definition bore hole seismic technology are rooted in its long-time prototype nature and the research/field trial approach it took to the market. Without question, much had to be learned about the science of bore hole seismic, its implementation and its potential for supporting better decision making, and tremendous progress has been made in all these areas. But next comes the hard part: proving the business case to competent operators whose financial metrics justifiably leave little tolerance for experimentation.

Although each has its own distinct specifications, the data recorded by today's bore hole seismic acquisition systems are stable and predictable. The biggest differentiations are in the processing software and the processed results. There are clear differences among the imaging systems developed by the various providers of the technology, but like all seismic data processing, there is a skill inherent to the geophysicists who process the data that is most often the difference between a poor and a great image.

But even with the best acquisition hardware, the best software algorithms and the best processing geophysicists, there remains a requirement to deliver results within operationally relevant time frames. Unlike the longer turnaround times for a surface 3-D seismic survey, reservoir management methods must affect the next drilling location, the current well completion and the near-term reservoir plans. Modernized workflows effectively deliver high-definition bore hole imaging results in a matter of weeks, but the goal must be to approach real-time delivery.

Along with reservoirs with complex stratigraphy and structure, significant beneficiaries of high-definition reservoir imaging are thermal recovery and CO_2 drive/sequestration, where the time-variant areal distribution of purchased drive fluids defines the effectiveness of the programs. In the high-cost world of generating steam and capturing/injecting CO_2, each dollar spent must deliver a multiple on its cost. Careful and precise monitoring of the injection effectiveness is crucial to maximizing the benefits. Conventional long-array VSP supports these processes and is especially useful in monitoring and verifying sequestered CO_2, an essential measurement in tomorrow's cap and trade economy.

Thermal recovery projects–such as steam-assisted gravity drainage, cyclic and steam drives–require high-temperature tolerances for instrumentation, ordinarily beyond the capacity of commodity sensor



Geologic complexities and errors such as undetected faults or misidentified edges can add significant operating cost and ultimately reduce recovery. High-resolution bore hole imaging is an effective way to achieve a detailed understanding of the reservoir to optimize performance over its full life cycle.

designs. Since some of the world's largest reserves are heavy oil, adapting high-resolution subsurface imaging to extreme temperatures must be a priority.

High-definition bore hole seismic is finding operational acceptance in reservoir management, and in many cases, is proving to be an alternative imaging technology to surface recorded 3-D seismic. Especially for mapping small-scale reservoir details and time-lapse monitoring of fluid distribution, the technology delivers precise and accurate data to optimally produce the reservoirs.

Over the past few years, the industry has brought several options to the market–each with its own specifications and price points–that allow operators to match the best solution to their specific application. The increasing use of this technology signals its evolution from experimental to mainstream, analogous to the acceptance of surface recorded 3-D seismic a couple of decades ago. The next few years will see broad acceptance of this mature technology as emphasis grows on optimizing reservoir performance in known fields to add reserves and accelerate cash flow. ❒

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