# Higher Resolution Subsurface Imaging

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***Editor's note:*** *This is the fifth in a series of articles on the great challenges facing the oil and gas industry as outlined by the SPE Research and Development (R&D) Committee. The R&D challenges comprise broad upstream business needs: increasing recovery factors, in-situ molecular manipulation, carbon capture and sequestration, produced water management, higher resolution subsurface imaging of hydrocarbons, and the environment. The articles in this series examine each of these challenges in depth. White papers covering these challenges are available at www.spe.org/industry/globalchallenges and allow reader comments and open discussion of the topics.*

## Introduction

It is hard to read road signs if you have poor eyesight, which is why driver's licenses are issued with restrictions requiring that corrective lenses must be worn. Likewise, it is hard to find and exploit subsurface resources if you can't clearly see your targets or monitor the movement of fluids in the reservoir.

Engineers now have powerful tools to precisely model subsurface reservoir production behavior, but a precise answer is still wrong if it is derived from an inaccurate subsurface description. Geoscientists make maps and rock property models of the subsurface by interpreting images that are produced from remote sensing data. Analogs from modern depositional environments and outcrop exposures guide subsurface data interpretation to predict ahead of the bit, then postdrill geostatistics are used to fill in stratigraphic details between wellbore control points. Selection of the right depositional model, facies distribution, and geostatistical analog depends on having the sharpest, most detailed and accurate image of the subsurface possible—the Grand Challenge of Higher Resolution Subsurface Imaging.

Over the past century, the industry has relentlessly sought ways to improve subsurface imaging of hydrocarbons. Canadian inventor Reginald Fessenden first patented the use of the seismic method to infer geology in 1917. A decade later, Schlumberger lowered an electric tool down a borehole in France to record the first well log. Today, advances in seismic and gravity data acquisition, electromagnetics, signal processing and modeling powered by high-performance computing, and the nanotechnology revolution are at the forefront of improved reservoir imaging.

In this paper, we will examine the challenges of getting higher resolution subsurface images of hydrocarbons and touch on emerging research trends and technologies aimed at delivering a more accurate reservoir picture.

## The Problem Statement

Hydrocarbon accumulations occur thousands of feet below the Earth's surface and the days of finding subsurface hydrocarbons through extrapolation of surface geology are all but gone. Now exploration is done with remote sensing tools that seek to generate sharper pictures with greater detail of the lateral and vertical changes in subsurface rock layers and sometimes the porosity and pore-filling hydrocarbons we require. If you have ever seen an aerial photograph of a delta, you can imagine what a subsurface reservoir could look like—channels and depositional bars hold the coarsest sediments with the most porosity while oxbow lakes and floodplain muds can be seen as potential barriers to flow. Now imagine that instead of air between the observer and the geologic feature, you must see through countless layers of rock with complex physical properties that obscure or muddle your vision of the delta below. Further imagine that you have a handful of well penetrations in your delta that stretches over several square kilometers and you want to see how produced and injected fluids move between wells.

The industry's goal is to continuously improve the subsurface images needed to better find and produce hydrocarbons in reservoirs such as this. Obstacles to this goal include remote-sensing limitations imposed by the physics of the rocks themselves (e.g. energy attenuation with depth, bed thickness and lateral extent relative to signal wavelength, and variable rock velocity and density properties that can scatter or complicate input signal), as well as instrumentation and computing power limits. On top of the technology challenges, there are economic considerations. If it costs more to acquire an advanced dataset than you can hope to recoup from a development, the technology might as well not exist. We recognize that absolute accuracy and precision will never be achieved, no matter how good our technology becomes, since all measured data are imperfect. The "grand challenge" is to achieve the truly fit-for-purpose subsurface image at good economic value.

Research that addresses imaging limitations is advancing worldwide on a dizzying array of technologies, but the problem is complex. Sometimes the res-

ervoir target is undermasking layers of salt, thrust sheets, or volcanics. It may be more than 30,000 feet below the surface, hidden within a producing field, or have physical properties that are nearly indistinguishable from surrounding rocks. The problems generated by imaging through a complex and unknown medium highlight not only the challenge to achieve higher resolution, but also concerns on depth conversion. Diffracted, attenuated, and multiply reflected signal energy can result from the complex physical property structure of rock layers to degrade subsurface imaging, but a higher resolution of the image is only part of the challenge. Accurate placement of a target can be even more critical and correct depth placement is especially important for exploration drilling in areas of overpressure. Increasing computational power, multicomponent and rich azimuth data collection, and algorithm efficiency are bringing the industry forward toward a more accurate and detailed Earth model that uses all of the signals possible in seismology; even better seismic data acquisition and processing technologies are needed.

Only a minuscule fraction of the subsurface can be directly observed: the portion generally less than 12 inches in diameter that is penetrated by boreholes. Directly observed, that is, if cored, otherwise indirectly observed through well logs. Well logs can sense a short distance into the formation, depending on the character of the signal/receiver setup, but the tradeoff is depth into the formation at the expense of vertical resolution. Moving just a few meters away from the wellbore puts reservoir imaging back into a remote sensing problem with limitations for our ability to illuminate and view the region. Generally, sources and receivers must be placed far away at the surface and energy propagated a long distance to the target and back. Correspondingly, there is a large drop in resolution. Compare this situation with the medical imaging problem, which allows X-ray sources and detectors to be used around the patient. In some cases, geophysical sources and receivers can be placed much nearer to the zone of interest along wellbores, but then it like trying to see through a key hole; the source and receiver locations may or may not adequately illuminate the region that we want to image.

Reflection seismology is the most used remote sensing method in geophysics. Seismic data delineates subsurface velocity and density variations, but if rock properties are favorable, they can be used to distinguish hydrocarbons versus formation water in a reservoir. Repeated 3D surveys over the same area can track fluid movement through time (4D). However, 4D surveying has its challenges:

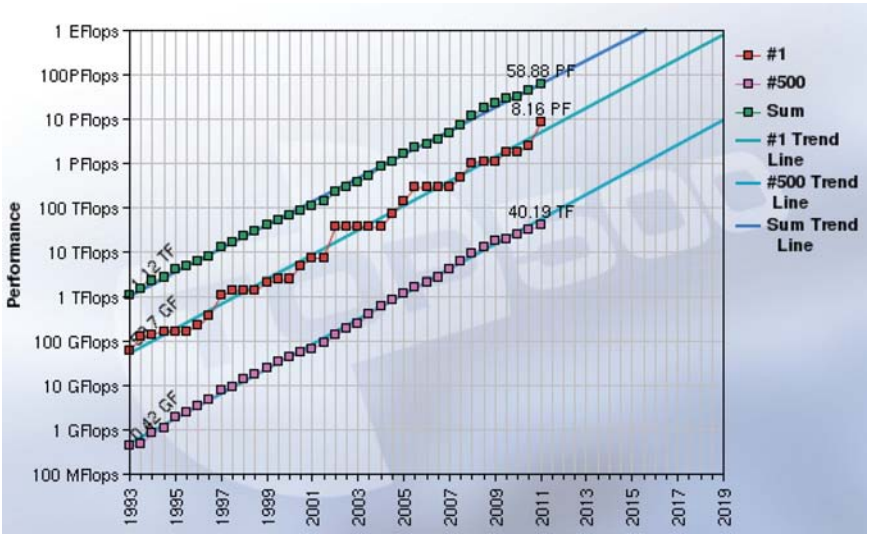


Fig. 1—Processing speed in flops (floating point operations per second) through time of the top 500 published computers and the sum total global capacity.

time to acquire, process, and accurately align with past surveys, limits in coverage caused by production facilities, and limits in resolution due to earth physics and illumination. Furthermore, it is costly.

Emerging technology of cross-well geophysical imaging offers to bridge the gap between high resolution well logs and surface seismic resolution, but the technology has significant limitations and has not reached broad application. There is a great need for improved technologies that image reservoirs and pore-filling fluids at high resolution within producing fields while operating within the constraints imposed by the environment. With the growth of unconventional resources that require stimulation to produce at economic rates, imaging of the stimulation itself has become a hot topic for research and development. The understanding of these rocks as reservoirs is still in its infancy compared with conventional reservoirs. Therefore, additional research into resolving controls on unconventional resource producibility remains a challenge.

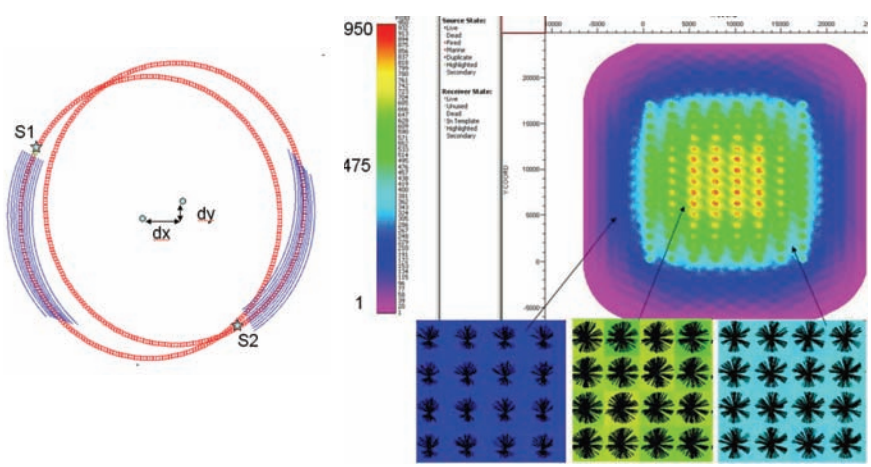


Fig. 2—Dual coil shooting acquisition. Left, two source and recording vessels, S1 and S2, sail along two circles (12–15 km in diameter) that have the centers separated by dx and dy distances. Right, coverage fold (data density) and bin offset-azimuth distribution (spider diagram—data richness); the bin size used to calculate the attributes was 25 m×25 m (Moldoveanu and Kapoor, 2009)

## Reflection Seismology

What progress is being made toward delivering more accurate and higher resolution subsurface images? Seismology has earth physics challenges to overcome. Signals sent into the ground are reflected, refracted, diffracted, mode converted, and attenuated as they pass through layers of the earth. At greater depth, signal attenuation reduces resolution. Under complex geology, distortion of the wavefield can give false images. The past few years have seen a flurry of innovation and image improvement, due largely to advances in computing speed, which continues to follow Moore's Law by averaging a doubling of processing speed every year up to the current record holder that is capable of 8 petaflops (8 quadrillion calculations per second—**Fig. 1**) processing. What all that computing power allows is the mathematical transformation of 10s to 100s of terabytes of data recorded in a modern survey into images that geoscientists can interpret.

The processing capability increase has occurred in parallel with data recording advancements such as multicomponent and high effort, multi-azimuth surveys now common in areas of the greatest imaging challenges such as the Gulf of Mexico sub-salt plays. Enabling this type of data-rich survey is instrumentation to record an increasing number of channels, a capability that has doubled every three and one-half years since 1970, with 1 million channel acquisition in the near future. These new acquisition capabilities seek to illuminate geology previously hidden by complex rock structure. Additionally, data recorded at far offset angles and azimuths, capturing shear waves in addition to compressional waves, can provide information on rock anisotropy that may be driven by differences in

lithology, fracture density, or pore fluids. Greater recording capabilities have led to new methods of acquisition and processing aimed at capturing a broader range of frequencies (bandwidth) of seismic signal, without introducing too much noise. Increased bandwidth is a key to higher resolution seismic reflection images.

The current frontier for seismic acquisition includes cableless and wireless recording, high-density rich-azimuth recording with simultaneous sources, higher quality land seismic, and low frequency signals. Both cableless and wireless recording are very attractive concepts, enabling easier and safer seismic data acquisition in remote or sensitive environments. Cableless systems with local memory are commercially available, but the data cannot be collected in real time. Although not yet ready to be deployed at large commercial scale (Crice, 2011), wireless sensors are promising. Success will come if the limitations of wireless transmission bandwidth needed to accommodate seismic data recording rates and volumes can be overcome, and if recording and real-time QC objectives can be met through advances in memory and battery power. Several contractor groups are promoting this technology, including a Shell/HP partnership

Higher quality land seismic data is the focus of the 2011-2014 SEAM II project (Society of Exploration Geophysicists Advanced Modeling), an industry associate group targeting three core challenges: high density geometries, near surface complexities, and fractured reservoir characterization (www.seg.org/SEAM). A key enabling technology for better land seismic data is simultaneous sourcing, which is the capability to acquire returning signal from one source while another is still propagating through the earth. Mobil developed and licensed a High Fidelity Vibroseis System (HFVS) in the late 1990s to separate data from multiple vibrators operating simultaneously (Krohn and Johnson, 2006). Although the concept is not new, widespread application has only picked up recently with increased high-performance computing, instrumentation with greater recording channel counts, increased multicomponent data acquisition demand, and the constant pressure on cost reduction. Data collection from simultaneous source locations has the potential to significantly increase efficiency in acquiring high-density surveys (Beasley, 2008), now extended into the marine realm. With new dual coil acquisition surveys, very high data fold and full azimuth coverage can be achieved (**Fig. 2**) to better stack and migrate seismic data, improve signal-to-noise ratio and resulting image quality, and it can be

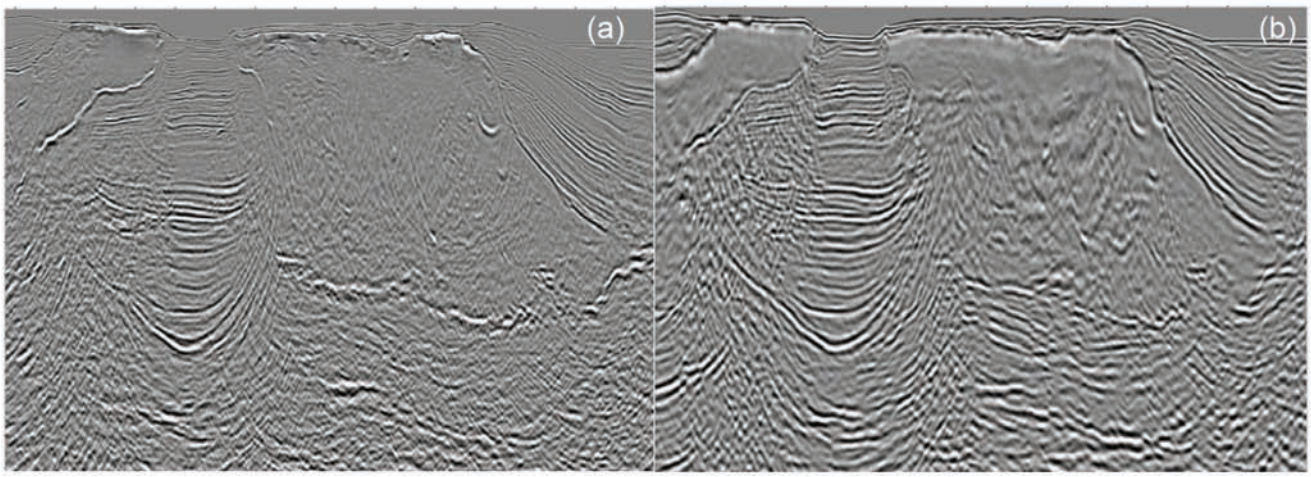


Fig. 3—An east-west line image of a 3-D data set in the Gulf of Mexico: (a) Kirchoff migration and (b) RTM (Kim et al., 2011)

made even more cost-effective by using simultaneous sources.

Low-frequency data has been a target for processors seeking greater bandwidth for years. This low-frequency extension of bandwidth is particularly important in its ability to penetrate deeper into the earth and through rugose layers such as basalt, salt and volcanics. Also, a body of work exists to suggest low-frequency signals and spectral analysis as a direct hydrocarbon indicator (DHI) tool (Walker, 2008). Challenges to acquire this data type lie in the need for nonstandard sources, including passive monitoring of earthquake signals, and increasing signal-to-noise ratios. Generating sufficient low-frequency signal energy requires very large sources. The presence of much larger environmental noise and surface-wave noise further complicates low-frequency data acquisition. Low-frequency data may ultimately become another competitive DHI tool; even if not, the collection of this data may be a key to the next breakthrough in subsurface imaging—full wavefield inversion.

Full wavefield and general seismic inversion is the other aspect of improved subsurface resolution that increased computing power enables. Seismic inversion is the process to convert seismic data into a rock property realization. The flip side of this process is seismic modeling, in which geologic realizations are converted into seismic images by passing a seismic signal of some frequency through the geologic model. Inversion modeling can be done at many scales and with different levels of conditioning. Quantitative rock property inversion can be done at a field scale with well log calibration of the seismic signal. Of interest to engineers are parameters such as porosity and permeability that must be derived through calibrated transforms using well data or empirical approximations. A good inversion produces a geologic realization that matches the recorded seismic signal. Full wavefield inversion is the purest form of the technique. In it, all output data collected from the reflected, refracted, diffracted and converted energy modes are used to create a visco-elastic earth model. Currently, this capability is out of reach despite marketing claims of "full wavefield inversion," which really invert parts of the wavefield using simplifying assumptions. Still, amazing results have been achieved by partially solving the problem, thus showing the promise of the technique.

Reverse time migration (RTM) is a processing technique that uses the wave equation in reverse to model the subsurface velocity field and obtain improved images of geology at steep dips or under salt (**Fig. 3**). Current industry capability is acoustic RTM or isotropic elastic RTM, using a simplified version of the wave equation. Elastic RTM without isotropic assumptions is emerging with increasing computing power to include more of the wavefield in image reconstructions, promising even more imaging improvement. Inverting for an earth model that matches the recorded data takes massive computing power and could be limited in effectiveness without the fullest possible bandwidth, especially the low-frequency spectrum. RTM data has demonstrated improved sub-salt imaging, but it cannot solve all the subsurface resolution and detection challenges such as fluid effect, subvolcanics imaging, and complicated velocity thin bed imaging.

## Imaging Within a Field

Time-lapse (4D) acquisition of seismic data over a producing field to image movement of fluids in a reservoir has obvious benefits, but the practical matters of actually achieving that objective have slowed deployment of the technology. In a recent special section of *The Leading Edge*, case studies presented show the promise and challenges to 4D seismic data acquisition as it evolved over the past 20 years to gain wide acceptance in the marine environment, particularly among the reservoir engineering community as a complement to production logging techniques (MacBeth and

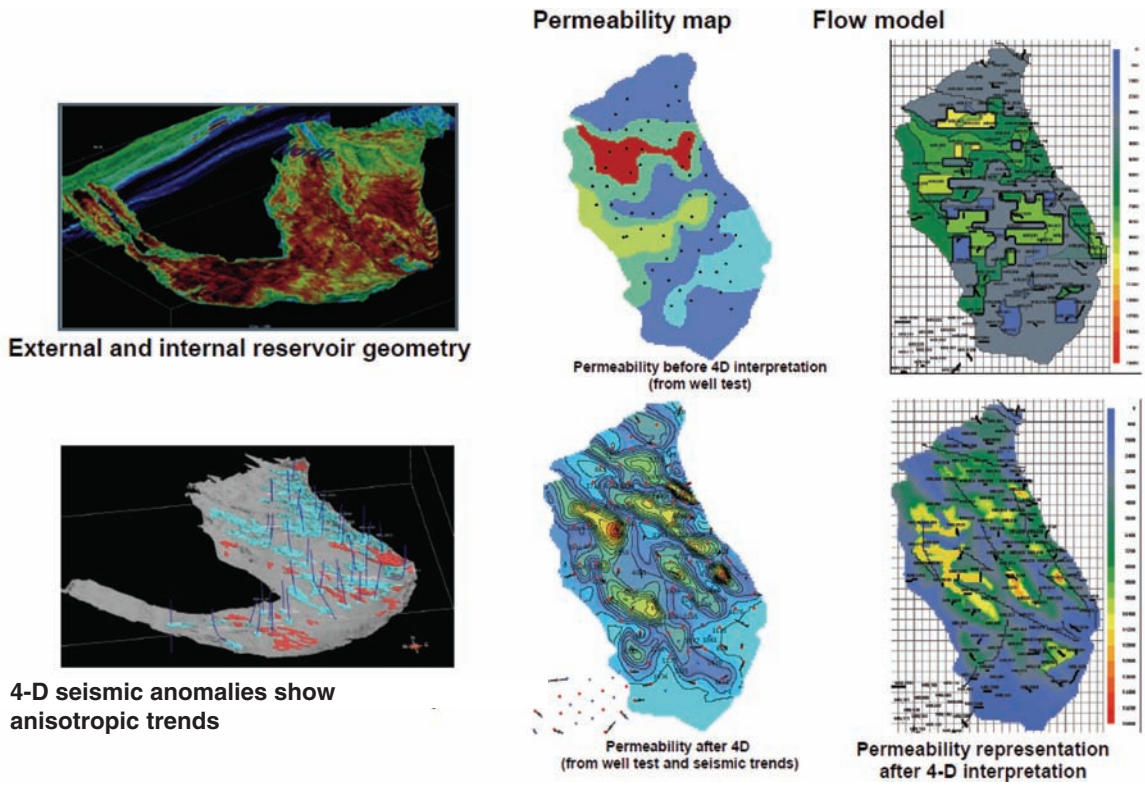


Fig. 4—Effect of 4D seismic interpretation at Marlim field, offshore Brazil, on the field flow model. New 4D data water flood anomalies confirmed a new conceptual sedimentological model of the field that differed from the flow model constructed just from well data (Johan et al, 2011)

Michelena, 2011). Planning early in field development for 4D seismic acquisition over the field life is beneficial because repeat surveys take significant time to acquire, process, and accurately align with past surveys. Permanent geophones or ocean-bottom cable options help some of the alignment challenges and can produce a better result. The upfront cost of this investment is a difficult hurdle for many operators to overcome. It is hard to quantify before production start just how much benefit 4D images will have over a field's life. The one constant of 4D acquisition seems to be that the results will surprise you. Repeat survey results continually change flow models to drive better field production history matches, which improve predictability and bypassed pay identification (Johan et al., 2011). If the data are collected and processed correctly, those surprises should help an operator to more profitably develop fields, even if they dramatically change the existing understanding.

## Alternatives to Surface Seismic

Not all technologies targeted to improve subsurface resolution of hydrocarbons involve traditional reflection seismology. Advances in field instrumentation sensitivity and robustness combined with improvements to computer modeling capabilities have brought several alternative geophysical sensing technologies onto a higher resolution hydrocarbon imaging plane. Microgravity, crosswell seismic, and controlled source electromagnetic (CSEM) imaging are alternative geophysical technologies that have been used in field examples to track fluid movement in reservoirs. Time-lapse microgravity technology shows promise as a low-cost alternative to 4D seismic for shallow reservoirs as instrumentation and modeling capabilities improve (Krahenbuhl et al., 2011). This technique was meticulously applied over Prudhoe Bay, Alaska, for a period from 2003 to 2007 to confirm a microgravity signal to enable water flood surveillance in the giant field (Ferguson et al., 2008). This work highlighted the challenges to achieving a reliable baseline for corrected measurements, but also showed the technology feasibility. Modeling work to track $CO_2$ injection for sequestration and enhanced oil recovery shows a time-lapse microgravity signal when oil and water are displaced, consistent with an independent analysis with seismic data (Krahenbuhl et al., 2011). High-quality reservoir models, precise measurement, and careful quantification of uncertainty are required to gain full benefit from time-lapse microgravity but the low cost makes the effort worthwhile.

Crosswell CSEM was described as a practical subsurface hydrocarbon detection tool by Wilt et al. in 1995. As instrumentation and modeling capabilities have improved, the technology moved from basic detection to potentially providing higher resolution imaging of subsurface fluid movement. By inducing

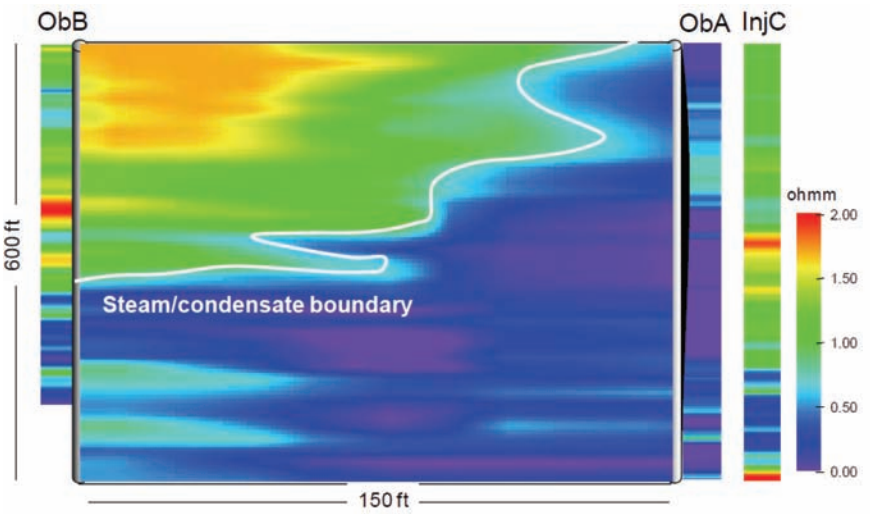


Fig. 5—Crosswell resistivity profile after steam injection, recording a dramatic drop in resistivity once the formation has been heated (Marion et al., 2011)

an electrical signal into the ground and recording resistance between source and recorder locations, the technology provides insight, through advanced modeling, into the distribution of resistive hydrocarbons and conductive formation waters. With source and receiver pairs at reservoir depth between two wells, the resistance structure can indicate reservoir complexity at higher resolution than surface remote sensing methods such as seismic data. Crosswell seismic acquisition can also offer resolution uplift although challenges of cost and conditions for downhole sources remain, and similar results might be obtainable through offset vertical seismic profiling. While CSEM can produce unique insight under the right circumstances, there are challenges to overcome in modeling non-unique solutions to resistivity profiles and finding a solution to the limitation that data be collected in openhole or specially cased wells. If these hurdles can be surmounted, crosswell CSEM could become a powerful tool in brownfield developments to identify bypassed pay and image waterflood sweep efficiency.

Nanotechnology is at the cutting edge of technology for higher resolution reservoir imaging with fundamental research ongoing at many universities. The Advanced Energy Consortium (AEC), managed from the University of Texas at Austin, seeks to "develop intelligent subsurface micro and nanosensors that can be injected into oil and gas reservoirs to help characterize the space in three dimensions and improve the recovery of existing and new hydrocarbon resources" (www.beg.utexas.edu/aec/mission.php). Conceptually, nanomaterials can be used as highly mobile contrast agents that can be detected with remote sensing. If imbued with intelligent sensing and recording capabilities themselves, nanometer-scale machines may one day fully illuminate and describe subsurface reservoir conditions. Research to achieve these goals is under way today, even if commercial application is a long distance into the future. The promise of higher resolution subsurface imaging through functionalized nanocomposite materials injection into reservoirs for remote sensing is one to watch.

## Imaging Unconventionals

No overview of higher resolution subsurface imaging would be complete these days without a discussion of unconventional resources, namely tight gas and shale gas/liquids. These resources have distinct imaging needs. For example, natural fracture imaging in the subsurface is sought to determine geologic sweet spots or areas to avoid, depending on your play success needs. Multicomponent or azimuthal seismic data can identify anisotropy that may be related to fracture density and orientation. Such knowledge is useful in well stimulation frac design or to avoid areas where fractures may have connected aquifers to tight gas reservoir. Multicomponent and azimuthal seismic also has the potential to identify areas of greater organic content since organics in shale have been demonstrated to produce a transverse anisotropy that can impact Vp and Vs and produce an amplitude versus offset effect (Vernik and Nur, 1992).

Microseismic data acquisition technology records seismic energy generated from rocks breaking in the subsurface as a result of induced fracture stimulation in a well. Data from the recording of microseismic events can be used to predict a well's relative productivity or identify incomplete stimulation and infill opportunities. In new shale gas plays where the geomechanics of the shale reservoir are unknown, microseismic is now routinely collected to determine play potential and to confirm isolation from adjacent aquifer zones. In established plays, the technology can help optimize lease development by identifying refrac needs or calibrate well drainage to space infill drilling more efficiently and avoid interference. New insight into the nature of fracture stimulations is now emerging with microseismic moment tensor data recording that combines with geomechanical analysis to produce a clearer picture of stimulated rock volume and ultimately assist unconventional reservoir model simulations (Maxwell and Cipolla, 2011).

## Conclusion

Higher resolution subsurface imaging of hydrocarbons is one of SPE's Grand Challenges for a good reason. As long as the industry has sought to find and exploit subsurface resources, it has sought to see them better. The challenge is difficult. We are largely restricted to source and receiver locations on the surface of the earth, trying to illuminate deep targets and resolve images through a complex and unknown medium.

The good news is that much progress is being made to improve our capabilities and data coverage. Seismic data covers much of the planet, with more and higher quality 3D and 4D data each year. Advanced computing capabilities permit construction of more detailed inversion models from the collection of high-quality datasets. Improved acquisition technology is gathering new data in places and ways previously beyond reach. New nanotechnologies offer great potential for improved subsurface imaging with advances in the fundamental sciences, but this potential remains a distant reality. The "bad" news is that earth physics complications will mean that improvements can always be made, which translates into job security for scientists and engineers. **JPT**


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