Seeking the Sweet Spot: Reservoir and Completion Quality in Organic Shales

Karen Sullivan Glaser
Camron K. Miller
Houston, Texas, USA

Greg M. Johnson
Brian Toelle
Denver, Colorado, USA

Robert L. Kleinberg
Cambridge, Massachusetts, USA

Paul Miller
Kuala Lumpur, Malaysia

Wayne D. Pennington
Michigan Technological University
Houghton, Michigan, USA

Placement of horizontal wells in shale reservoirs can be a costly and risky business proposition. To minimize risk, operators acquire and analyze surface seismic data before deciding where to drill.

In the late 20th century, E&P geoscientists began to consider shales in a new light. Although production from shales had been established in the early 1800s, operators considered shale formations mainly as source rocks and low-permeability seals for conventional reservoirs. However, during the 1980s and 1990s, operators showed that the proper application of horizontal drilling combined with multistage hydraulic fracturing could make organic shales productive, spurring the exploitation of organic shales as self-sourced reservoirs. Despite the successful development of the Barnett and Haynesville shales in the US, the industry quickly realized that not all shales are viable targets for economic hydrocarbon production, and operators sought technologies that could identify appropriate targets for development.

Shale formations that offer the best potential require a unique combination of reservoir and geomechanical rock properties; such formations are relatively rare. Organic shales have extremely small pore size and ultralow matrix permeability, which makes these unconventional resource plays fundamentally different from most conventional reservoirs. Furthermore, because hydrocarbon migration paths tend to be short, productive zones of shale reservoirs may be confined to a certain area within a basin or restricted to a stratigraphic interval.

The two factors that determine the economic viability of a shale play are reservoir quality and completion quality. Good reservoir quality (RQ) is a collective prediction characteristic that is largely governed by mineralogy, porosity, hydrocarbon saturation, formation volume, organic content and thermal maturity.

Completion quality (CQ), another collective prediction attribute, helps predict successful reservoir stimulation through hydraulic fracturing. Similar to RQ, CQ largely depends on mineralogy but is also influenced by elastic properties such as Young’s modulus, Poisson’s ratio, bulk modulus and rock hardness. Completion quality also incorporates factors such as natural fracture density and orientation, intrinsic and fractured material anisotropy and the prevailing magnitudes, orientations and anisotropy of in situ stresses.

To be successful in today’s shale plays, operators drill horizontally within reservoir strata that possess superior RQ and CQ. Stimulation treatments are most effective when the induced fractures remain propped open, thereby exposing the reservoir to a large fracture surface area and allowing fluids to flow from the reservoir to the wellbore, effectively raising the reservoir’s system permeability.

Operators judge the quality of a hydraulic fracture completion design based on a postjob evaluation of data from sources such as microseismic monitoring of hydraulic fracturing, flowback tests and initial production to determine how effectively and efficiently the reservoir was stimulated.

Ideally, an operator places horizontal wells within shale intervals with favorable geologic characteristics and high RQ and CQ and without geohazards. Retrospective studies have demonstrated that this strategy would have resulted in
as much as a tenfold increase in production (below). Determining where the best RQ and CQ coincide is therefore an exploration effort, and the best technique to enhance the exploration effort, before drilling the initial well, is interpretation of surface seismic data. Recent studies have indicated that seismic interpretation is useful for defining production sweet spots within organic shale plays.

In this article, we describe a systematic and strategic approach for using surface seismic data to identify reservoir sweet spots in shale resource plays, starting with basal and regional RQ and progressing toward local RQ and CQ. Case studies from the Arkoma, Delaware and Williston basins in the US demonstrate how reflection seismic data provide the key to determining where a resource play may exist and where RQ and CQ are highest.

**Mudstone Characteristics**

Geologists define shales as mudstones that exhibit fissility—the ability to split easily, like a deck of playing cards, into individual laminae. The oil and gas industry typically considers resource plays as gas- or liquid-producing “shales.” However, it would be more accurate to call them mudstones or mudrocks, because these “shales” often are not fissile.

Mudstones dominate the sedimentary record and make up roughly 60% to 70% of Earth’s sedimentary rocks. They are fine-grained sedimentary rocks composed of clay- and silt-size particles with diameters of less than or equal to 62.5 micron (0.00246 in.). These small particle sizes result in low permeability; poor sorting—the mixing of various grain sizes—can further reduce both permeability and porosity.

Mudstones have a complex mix of organic matter and clay minerals—illite, smectite, kaolinite and chlorite—along with quartz, calcite, dolomite, feldspar, apatite and pyrite. Geologists with Schlumberger recently introduced the sCore ternary diagram mudstone classification scheme, which is built on relationships established between core and log, using clay, QFM (quartz, feldspar and mica) and carbonate as the corner points. The sCore diagram defines 16 classes of mudstones and can classify a sample as an argillaceous (clay-rich), siliceous or carbonate mudstone. This classification scheme allows geologists and engineers to examine empirical relationships between mineralogy and factors that influence the RQ and CQ of mudstones by overlaying points that include indications of RQ, CQ or both (next page).

Productive mudstones most sought by oil companies tend to be dominated by nonclay minerals, principally silicates and carbonates, and therefore lie in the lower part of the diagram, away from the clay point; higher RQ and CQ rocks are near the edges of the triangle.

Several factors control the physical properties of mudstones: the mineralogy and proportions of grains, the fabric of the originally deposited muds and the postdepositional processes—such as resuspension, redeposition, diagenesis, bioturbation and compaction—that convert mud into rock.

Mudstones tend to be highly heterogeneous, and this heterogeneity can vary horizontally and vertically, originating from the sequence of depositional environments and tectonic regimes that prevailed as the mud strata stacked up through geologic time.

An individual layer of mud, called a lamina, is typically about a millimeter thick. Laminations stack up to form laminae sets, called beds. Beds in turn stack up to form bed sets that group together into members and then into genetic or depositional formations. The mineral and organic composition of each layer depends on the sequence...
sCore classification tool. In the clockwise direction, the corners of the sCore ternary diagram (top left) are clay, carbonate and quartz plus feldspars plus micas (QFM). The diagram defines 16 classes of mudstones based on mineralogy. The mudstones (top right) sought by oil companies tend to have less than 50% clay. In the Wolfcamp Shale (middle), siliceous mudstones exhibit high RQ and CQ. In the Eagle Ford Shale (bottom), carbonate mudstones have high RQ and CQ. In these examples, RQ is directly proportional to effective porosity and CQ is inversely proportional to the stress gradient of the minimum in situ principal compressive stress.
or history of geologic conditions of the area through time. Geologists use the principles of stratigraphy to decipher this geologic history.11

Layering has a particular effect on some rock properties: It is a fabric that causes anisotropy.12 A rock is anisotropic if its properties vary with direction.13 A consequence of layering is that the composition, size, shape, orientation, packing and sorting of the particles in the layer tend to vary more quickly perpendicular to, rather than parallel to, layers. As a result, rock properties tend to vary with direction. They are different if measured layer parallel than if measured layer perpendicular. Another aspect of rocks that can lead to anisotropy is the presence of roughly parallel open fracture networks, which can control the efficiency of reservoir stimulation. Because anisotropy is observable in seismic data, geophysicists are able to characterize it for geologists and engineers to use in their various geologic, geomechanical and fluid-flow models of the prospective reservoir (below).

Mudstones play an important role in a petroleum system. Their small grain sizes and sorting characteristics contribute to their characterization as low-porosity rocks with low to ultralow permeability and high fluid-displacement entry pressures. Consequently, when mudstones are in the correct stratigraphic and structural location and configuration, they form the seals that cap and delimit conventional hydrocarbon reservoir geometries.

Some mudstones are characterized as organic rich, and these have been viewed historically as the source rocks that, through secondary migration, supply hydrocarbons to adjacent and remote conventional and unconventional continuous reservoirs. These same organic-rich mudstones have also proved to be self-sourcing reservoirs, yielding hydrocarbons that have been expelled and undergone primary migration to be stored within the source rocks themselves.14 For example, the Eagle Ford Shale in south Texas, USA, is a mudstone that sources the prolific Austin Chalk fractured reservoir, which has been explored and produced for more than 80 years. Now, operators recognize the Eagle Ford Shale itself as a reservoir capable of producing oil, condensate, wet gas and dry gas that simply never left the source rock.15

Not all mudstones contain sufficient hydrocarbons to be considered potential reservoir rocks. Mudstones are defined as organic rich if their total organic carbon (TOC) concentration is greater than 2 weight %.16 The preservation and

^ Mudstone layering at many scales. Layering may be observed in photographs of outcrop, core and thin section. The Eagle Ford Shale outcrop (left) is in Lozier Canyon in Terrell County, Texas. The images of core (plain and ultraviolet light, center) and thin section (original and close-up, right) are of lower Eagle Ford Shale from the BP-Schlumberger Lozier Canyon number 1 well. The 2-ft [0.6-m] core length was cut from depths 226 to 228 ft [68.9 to 69.5 m]. The thin section is of fossiliferous siliceous-calcareous mudstone and has a mineralized fracture running along its right side, which has been stained with potassium ferricyanide and alizarin red S dye to distinguish carbonate minerals. In the close-up view from the thin section, there is evidence that the fracture propagated, stopped and restarted along a different path. (Outcrop photograph courtesy of Karen Sullivan Glaser. Core and thin section images courtesy of Schlumberger and BP America Incorporated.)
richness of organic matter depend on the relative rates of its production, dilution and destruction (right). Inorganic matter deposited at the same time as organic matter will dilute organic matter concentration. Destruction of organic matter occurs through bacterial consumption, by oxidation reactions at shallow depths and by deeper thermally activated reactions, which transform part of the organic matter into oil and gas before it ultimately changes to graphite, or dead carbon. The primary portion of organic matter in source rock is kerogen, which is insoluble in common organic solvents; the other portion is bitumen, which is soluble.

Kerogen has petrophysical characteristics that differ significantly from those of the mineral constituents in shale, and these characteristics affect the overall bulk properties of the reservoir rock. For example, depending on kerogen type and maturity, the density of kerogen can vary from 1.1 to 1.4 g/cm\(^3\), considerably less than the bulk density of its shale host rock. Consequently, the bulk density of organic-rich shales appears lower (as if the shale has a higher porosity) than that of shales containing lower concentrations of kerogen.

The distribution of kerogen varies from isolated particles dispersed through the mudstone matrix to lenses and sheets aligned with mudstone laminae. Investigators have found that kerogen particles contain secondary porosity that likely formed during thermal maturation. This organic porosity occurs as nanopores, defined as less than 1 micron in diameter.

^ Organic matter. The thin section (left), which has been stained with potassium ferricyanide and alizarin red S dye on its left side, is of calcareous pelletal mudstone. In the close-up view (right), the layer is composed of planktonic foraminifera (white and pink), flattened fecal pellets (reddish brown) and organic matter (black). (Core and thin section images courtesy of Schlumberger and BP America Incorporated.)

Kerogen fabric affects the physical properties of organic-rich mudstones. When the organic content is high and the kerogen forms interconnected layer-parallel networks through the mudstone frame, the organic porosity may be sufficient for hydrocarbon storage and for providing permeability to gas and liquid hydrocarbon in an otherwise extremely low-permeability matrix.
In addition, kerogen fabric affects the elastic and mechanical properties of reservoir rocks.21 Generally, mudstones that contain interconnected kerogen within their frame are characterized by lower elastic moduli and higher ductility compared with those mudstones that have isolated kerogen particles dispersed through their matrix. Kerogen content distributed parallel to the laminae may profoundly affect the anisotropic elastic and mechanical properties of mudstones.22 These effects will be enhanced if, in addition to creating secondary porosity within kerogen, hydrocarbon generation and charging of the kerogen-rich laminae cause overpressuring, a condition that is conducive to creating layer-parallel microcracks, which strike parallel to layers and open perpendicular to them.23 Because matrix permeability in shale reservoirs is exceptionally low, ranging from 10⁻² to 10⁻⁴ mD, natural fractures play a significant role in reservoir completions and hydrocarbon production.

Natural fractures contribute to the performance of hydraulic fracture stimulations by providing planes of weakness and conduits for fluid flow.24 As planes of weakness, natural fractures may dictate the propagation and development of induced fracture networks, especially if the in situ stress anisotropy is low.25 As conduits for fluid flow, these fractures may enhance the extent of effective reservoir volume drained by the wellbore, and they may admit high-pressure fluids, which could cause permanent shear slippage along their fracture planes and increase fracture aperture and conductivity.

Local RQ sweet spots in prospective mudstone reservoirs often contain natural fractures that provide flow pathways connecting matrix porosity and storage to hydraulic fractures and the well. Natural fractures may also affect CQ through the geometry of stimulation-induced hydraulic fracture networks, which tend to become more widespread and complex when preexisting natural fracture networks are oriented at an angle to the present-day principal horizontal stress.26 When mudstone reservoirs lack natural fractures, operating companies must rely on hydraulic fracture stimulations to create induced fracture networks that connect production from the reservoir matrix to the wellbore. Therefore, natural fractures, which can increase both RQ and CQ, are a seismic exploration target in the hunt for sweet spots in shale reservoirs.

Through the analysis of seismic attributes, geophysicists detect and characterize fracture networks. This process takes advantage of the volume-averaged response from the entire reservoir interval containing an open natural fracture system.27 Numerous fracture detection methods use seismic attributes. When natural fractures align in a consistent strike orientation, they cause elastic properties and seismic attributes to vary with azimuth, including velocity and reflection amplitude.28 Geophysicists observe these variations from analysis of 3D surface seismic surveys that have been acquired along multiple azimuths.29 Azimuthal analysis of shear waves (S-waves) has proved to be a good fracture detection method.30 Analysis of seismic waveform scattering, which was often treated as noise in the past, may also reveal information about fracture orientation and spacing through frequency analysis.31 In addition, combinations of attributes such as reflection strength and seismic variance—the variation between seismic samples—may be blended, or superimposed, to expose subtle structural features that have fracture systems associated with them.32

Regional- or Basin-Scale Sweet Spots

During the initial years of the current surge in activity in shale plays, some operators were able to develop shale plays on the basis of hydrocarbon shows on mud logs that were recorded in shales encountered while drilling conventional reservoirs within a basin. The regions within these basins where organic shales are thermally mature were already known to the industry; therefore, for many of the shale plays in North America, it was unnecessary for operators to investigate the plays’ thermal maturity.

Because of the successful development of the Barnett Shale in the Fort Worth basin in north-central Texas, operators widened their search for shale gas beyond North America to basins that are less explored. In certain basins around the world, few wells have been drilled, and operators lack the level of understanding of the stratigraphic and structural framework to anticipate where potential shale resource plays exist. In these basins, initial exploration for potential shale reservoirs relies on evaluating preexisting 2D seismic surveys and additional structural data from remote sensing analyses and outcrop studies of surface geology.

Geoscientists evaluate these data to establish the structural framework of the major basinal
stratigraphic units, including the locations of major fault zones and other tectonic features. Once they complete this analysis, basin analysts can use the structural framework as input to petroleum system modeling to determine if organic shale formations might be thermally mature, and if so, where in the basin these may occur.27 When this information is combined with regional mapping of available TOC data, regional- or basin-scale sweet spots may be identified, enabling operators to select optimal locations for drilling initial vertical pilot wells in the next phase of exploration.

Local or Operating Area Sweet Spots
Petroleum system modeling predicts the location and characteristics of basin-scale sweet spots, including the distribution of kerogen content, its thermal maturity and the pore pressure within the prospective interval. However, these predictions can be confirmed only by drilling a pilot well. Core and logging measurements from the vertical pilot well provide data to update the modeling and determine whether the pilot well has intersects a sweet spot. Engineers can categorize local sweet spots by analyzing RQ and CQ using the newly acquired core and log data.

Local sweet spots of high RQ have one or more of three properties. Local sweet spots may have high matrix porosity that contains significant amounts of free gas, which may be produced at high rates during initial production, allowing for rapid payout of a horizontal appraisal well. In addition, sweet spots may have significant concentrations of kerogen. Kerogen-rich sweet spots also contain large volumes of adsorbed gas, which is stored mainly on kerogen surfaces.28 This adsorbed gas contributes to sustained production as pressure drops during reservoir depletion, long after the free gas has been consumed.

Local RQ sweet spots may also have dense networks of open microfractures. Similar to high-porosity sweet spots, densely fractured sweet spots contain free gas that is produced during the early production of a well. In addition, microfractures also increase the system permeability within a shale reservoir.

The best RQ sweet spots include all three properties—increased porosity, kerogen and microfracturing—which in turn affect various attributes of seismic data through their effect on rock properties. Increased porosity and the presence of fractures typically cause decreases in seismic velocity and increased attenuation of high frequencies. Concentrations of kerogen can also lower the elastic moduli and density of mudstones, but to a lesser degree. Changes in certain seismic attributes associated with these rock properties may be used to identify RQ sweet spots.

Correlating Frequency Anomalies to Production Behavior
In the Arkoma basin of southeast Oklahoma, USA, gas production has been established from the Woodford Shale, a Late Devonian-Early Mississippian age organic-rich mudstone. Its mineralogy is primarily quartz and illite, with small quantities of pyrite and dolomite. Porosity ranges from 3% to 9% and TOC ranges from 1 to 14 weight % [0.01 to 0.14 kg/kg].29

An operator targeting Woodford Shale gas production had drilled six vertical wells within a 4-mi² [10-km²] area. The wells’ production rates varied widely. In a 2.5-year period, cumulative gas production per well ranged from 18 to 372 MMcf [0.51 to 10.5 million m³] with average cumulative production from the five lowest producing wells of 40 MMcf [1 million m³]. The operator had acquired a 3D seismic survey over the field and requested that Schlumberger analysts interpret the data to determine why the production was so variable and to locate areas of potentially higher production.

The 3D seismic data provide far greater coverage of the reservoir interval than could be achieved by vertical or horizontal well data. The 3D seismic data were initially interpreted to locate faults and any other geohazards within the area, but the observed faulting and fracturing associated with fault damage zones could not explain the production history or the well-to-well variability.

Geophysicists analyzed the data for seismic attributes that would reveal RQ sweet spots. They identified a seismic frequency attribute that at certain frequencies corresponded with areas of higher production. These seismic sweet spot anomalies were areas in which the dominant seismic frequency proved to be relatively low, apparently the result of scattering of waves from networks of natural fractures or microfractures.36 The anomalies appeared as isolated patches within the field, and the team interpreted them to represent areas of increased porosity and microfracturing within the shale reservoir. Productive wells were located within these anomalous areas, while the underperforming wells were not. The well with the highest production is situated within a large anomaly (above). At the time of the study, this well had produced nine times the average production of the other
In another shale play, an operator was developing a combination fractured carbonate and gas shale unconventional reservoir in the Delaware basin of southern New Mexico and western Texas, USA. The company had drilled a number of horizontal boreholes at the interface between the carbonate and the underlying shale. Production from these wells varied significantly.

Schlumberger geophysicists analyzed a 3D seismic volume to help determine the location and extent of potential RQ sweet spots and define their geologic nature. The geophysicists performed prestack azimuthal inversion and several frequency-related studies. The results of these separate investigations converged on the same locations within the shale reservoir as potential RQ sweet spots. These sweet spots manifested themselves through specific frequency-related seismic attributes that were also coincident with zones of S-wave anisotropy. The team interpreted these areas to be volumes of enhanced microfracturing in the upper portion of the gas shale (left).

The operator drilled three horizontal wells along the carbonate/shale interface in the hope of encountering fractures within the carbonate formation and zones of high gas content in the shale. Production rates from these wells appeared to be directly related to the magnitude and size of the frequency anomalies and S-wave anisotropy. Well A was drilled across the top of a gentle anticlinal feature, where high seismic variance indicated the presence of faulting along the crest of the fold. At the time of the study, Well A was the best producer, with an average production rate of 64 MMcf [1.8 million m³] of gas per month. Well B was drilled near a smaller seismic frequency anomaly and its monthly production rate was 28 MMcf [0.79 million m³], less than half that from Well A. Well C did not penetrate a frequency anomaly and its monthly production rate was a poor 7 MMcf [0.2 million m³].

The team believed that the frequency anomalies highlighted zones within the shale that contained more microfractures than other locations. The concentration of microfractures at the crest of the anticline is consistent with the tectonic extension the layers experienced during anticline formation. Other evidence suggests that this fracturing did not extend through the full shale thickness. Zones of enhanced microfracturing within the shale were encountered by Well A and, to much lesser degree, by Well B, and resulted in the improved production observed in both wells compared with that in Well C.

Fracture detection with seismic frequency attributes. A seismic fence diagram composed of seismic cross sections and a horizon slice shows a frequency-related seismic attribute. The horizon slice is also blended with the seismic variance attribute (grayscale); only high variance values are shown. The fence diagram (inset) is formed from seismic sections along the trajectories of Wells A, B and C (dark blue). The horizon slice, which is taken along the top of the formation immediately below the shale reservoir, is curved by a gentle anticline. Along the anticlinal crest, the seismic variance and frequency attributes are high. Average monthly gas production rates, shown above each well’s lateral, illustrate how each well’s production rate corresponds to its proximity to strong frequency anomalies.

Gas shows encountered during the drilling of Well A (black line). A seismic section (background) is shown in a perspective view looking down and into it. The section is parallel to the trajectory of Well A and cuts through the 3D volume of the frequency attribute. High values of the frequency attribute (red and pink) appear as clouds coming out of the section. Gas chromatograph readings (blue curve), obtained from the mud log, are shown along the horizontal portion of Well A. Perforation cluster locations (cyan diamonds) align with the mud log depth points (small red triangles below the log curve). Gas shows from the mud log were strong when the wellbore was near high values of the seismically derived frequency attribute.
Examination of the gas shows encountered during the drilling of Well A also supported this interpretation (previous page, bottom). The strongest gas shows coincided with strong seismic frequency anomalies. Where the frequency anomalies were weaker, gas shows were not as strong.

In another location within the same Delaware basin study area, the operator drilled two horizontal wells from a vertical pilot well. The wells were drilled from east to west, hydraulically stimulated in multiple stages and monitored for induced microseismicity. The team was able to correlate the microseismic event locations to areas where seismic frequency anomalies were strongest (above). It was evident that high levels of frequency anomaly corresponded to RQ sweet spots or, more specifically, to zones of high porosity and increased microfracture density. In addition, these zones appeared to have favorable CQ.

Associating Anisotropy to Production Patterns

The Bakken Formation is an oil-producing petroleum system. Its stratigraphy represents deposition in a restricted, shallow water environment that existed throughout most of the Williston basin, which covers portions of Alberta, Saskatchewan and Manitoba in Canada and Montana, North Dakota and South Dakota in the US. The Bakken Formation is of Late Devonian–Early Mississippian age and lies unconformably above the Late Devonian Three Forks Formation and conformably below the Early Mississippian Lodgepole Limestone. The Bakken Formation has been subdivided into lower, middle and upper members. The middle member is the reservoir and is a mixed clastic-carbonate interval consisting of dolomitic sandstones, dolomites and limestone. The upper and lower members are organic-rich shales that serve as the seal and source for hydrocarbons.

The model for the Bakken Formation is one of a continuous petroleum system. The organic-rich upper and lower Bakken shale members have 8 to 10 weight % [0.08 to 0.1 kg/kg] TOC and are source rocks that generated oil that had migrated locally into reservoirs hosted by the adjacent middle Bakken member and the underlying Pronghorn, which includes the Sanish Sand member of the Three Forks Formation. Because of the relatively closed nature of this petroleum system, overpressuring occurs in deeper parts of the basin, where the most hydrocarbon generation has taken place. Pore space and fractures within the upper and lower Bakken shale members also provide reservoir storage.

Natural fractures can occur locally in the Bakken Formation, and where their intensity is sufficiently high, such as along the Antelope anticline in North Dakota, they can affect production. In general, the fractures are vertical to subvertical, bed bounded and partially to totally filled by quartz, calcite or, rarely, pyrite cements. Some vertical microfractures appear to be expulsion, or fluid release, fractures that form when fluid pressures exceed the prevailing minimum principal compressive stress, allowing oil to migrate from the source rocks into adjacent reservoir members.

The RQ (porosity and permeability) of the middle member, along with the degree of overpressuring, plays a large role in determining the productivity of the Bakken Formation. The ability to predict where better reservoir quality occurs dramatically increases the chance of success in this play.

For this reason, an E&P company operating in the Williston basin contracted with Schlumberger, whose geophysicists reprocessed a proprietary 3D multiazimuth seismic survey over an area within the Bakken play of North Dakota. The target reservoir horizon was in the middle Bakken member. The company wanted to base drilling locations on patterns of initial production and seismic attributes, which are both affected by characteristics of reservoir geology. The company hoped to move away from drilling wells based on geometric patterns—lease boundaries or the Public Land Survey System—which ignores geologic heterogeneity, and to take a deliberate approach to locate, orient and drill infill horizontal wells into highly productive reservoir locations.

Geoscientists constructed a calibrated geologic model that was constrained by all available data, including well logs, borehole image logs and core samples. Geophysicists processed the 3D
seismic data to account for horizontal variability and anisotropy of seismic velocities in the strata above the reservoir. Seismic processors sorted the seismic data into offset vector tile (OVT) gathers, in which traces share similar source-to-receiver offset and azimuth. Using high-resolution, multiazimuth OVT tomography, the processors modeled seismic velocities and anisotropy and used them for prestack depth migration (PSDM) of the OVT gathers. If there was disagreement between seismic picks of formation-top depths from PSDM and those from well data, the velocity and anisotropy model parameters were readjusted, and the tomography and PSDM steps were repeated until there was acceptable agreement between the geologic model and PSDM image.

Once the geologic model and PSDM image matched, subsequent processing could focus on the seismic anisotropic effects at middle Bakken reservoir depths that appeared to result from oriented geologic fabrics or stress anisotropy (previous page). The geophysicists used the fitted elliptical anisotropy from traveltimes (FEATT) workflow to find the fast and slow compressional-wave (P-wave) velocities and directions at the reservoir level.

The FEATT workflow starts by converting the PSDM OVT gather from depth to two-way traveltime. The analyst or an automated routine picks residual traveltimes across common offset-azimuth time horizons, converts the traveltimes to interval velocities and fits an ellipse to the velocities. The ellipse’s major and minor axes and their orientations provide estimates of the fast and slow P-wave velocities and directions (right).

Following application of the FEATT workflow, the geophysicists applied amplitude variation with offset and azimuth (AVOAZ) analyses to estimate S-wave velocity anisotropy. The AVOAZ analysis of S-waves may provide higher vertical resolution of the anisotropy variation than P-wave azimuthal anisotropy. The seismic data were sorted into offset vector tiles (OVTs) and converted to depth by conventional migration (top left) and by anisotropic prestack depth migration (PSDM) and tomography (top right). The latter process reduced the waviness in the data attributable to overburden effects and produced datasets appropriate for azimuthal anisotropy analysis. In both panels, the yellow zigzag line gives the azimuth distribution in the OVT, and offset increases from left to right. The PSDM OVT data (cyan box) were converted from depth to time (bottom left), and a horizon (red) was selected for fitted elliptical anisotropy from traveltimes (FEATT) analysis (bottom right). In this example, the seismic processors selected the minimum number of three points (red) required to fit an ellipse; in practice, processors use many more than three. Processors converted the residual moveout at each azimuth to P-wave velocity (the radius of the radial plot) and fitted a FEATT ellipse (blue points, black points and radii) to the input points. The ellipse yielded a fast P-wave velocity azimuth of 114.24° with a slow-to-fast P-wave velocity ratio of 0.974, or P-wave velocity anisotropy of 2.6%. (Adapted from Johnson and Miller, reference 41.)

44. Johnson and Miller, reference 41.
velocity anisotropy methods because of its sensitivity to interface contrasts rather than to the average cumulative response of overlying strata.45

The present-day Bakken Formation maximum in situ principal horizontal compressive stress direction determined from the hydraulic fracture stimulations is generally NE–SW.46 Vertical natural fractures observed in wells within the area of investigation were oriented NW–SE, in the present-day minimum in situ horizontal compressive stress direction. The fractures tended to be mineralized, had permeabilities in the micrdarcy to nanodarcy range and were not believed to be contributing to production.46 In addition, the RQ of the Bakken Formation in the area of investigation was poor to fair, which explains the low production rates.

The team compared the seismic anisotropy results to the first 90 days of production from wells across the field. Areas of low production correlated to those having weak P- and S-wave anisotropy, and areas of high production were associated with strong anisotropy (left). Anisotropy was weak to the west and strong in the east, which helped explain why the eastern part of the field was more productive than the western part. Along with production improvement from west to east in the area of interest, the anisotropy orientation changed from NW–SE in the west to NE–SW in the east. An improvement in matrix properties is one explanation for this change; in addition, geophysicists speculate that this change in anisotropy direction represents a change in natural fracture orientation from one side of the field to the other. In the east, NE–SW oriented fractures would be parallel to the present-day regional maximum in situ principal compressive stress direction. Initial production tends to be higher where the anisotropy is stronger. Analysts interpret the anisotropy to be associated with production sweet spots that are potential targets for drilling. (Adapted from Johnson and Miller, reference 41.)

Volumes of high anisotropy. This view of S-wave velocity anisotropy within the middle Bakken member is looking down and north. The orange and red clouds are volumes of low ratios of slow-to-fast S-wave velocity, equivalent to high anisotropy, extracted from 3D seismic data between the upper and lower Bakken members. The anisotropy is strong in the east and south and weaker in the northwest. The blue surface underneath the clouds is from within the lower Bakken member and shows the ant-tracking seismic attribute (black to white), which accentuates traces of faults and fractures. (Adapted from Johnson and Miller, reference 41.)

Production sweet spots. A seismic horizon through the middle Bakken member shows the slow-to-fast S-wave velocity ratio derived from AVOAZ inversion. The black arrows represent the relative magnitude of the estimated S-wave anisotropy; the arrow directions provide the fast S-wave vector azimuth from the inversion. The colored circles mark the average location of long horizontal wells and show the initial 90 days of oil production within the mapped area. To the west, the production was low to moderate, and S-wave velocity anisotropy is weak (blue to purple); the fast S-wave direction tends to be NW–SE. In the east, the production was higher, anisotropy is stronger (yellow to red) and the fast S-wave direction has a SW–NE trend, which is consistent with the present-day regional maximum in situ principal compressive stress direction. Initial production tends to be higher where the anisotropy is stronger. Analysts interpret the anisotropy to be associated with production sweet spots that are potential targets for drilling. (Adapted from Johnson and Miller, reference 41.)

46. Sturm and Gomez, reference 38.
47. Sturm and Gomez, reference 38.
The Value of Seismic Data

These examples of using surface seismic data to understand patterns of production have been retrospective rather than prospective. Operators continue to test and appraise the identified sweet spots with new wells.

An increasing number of operators are acquiring and analyzing 3D surface seismic data during the early stages—exploration, pilot and appraisal phases—in the operating cycle of organic shale plays. Suitably analyzed and interpreted seismic data have proved to be invaluable for guiding the placement of initial wells within a frontier shale basin, appraisal wells within a prospective shale basin and infill wells as part of a field development program in a mature basin. —RCNH