Seismic Applications Throughout the Life of the Reservoir

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Operators are getting more from their reservoirs by combining high-quality seismic images with conventional reservoir data. Asset teams use this calibrated seismic information to gain detailed knowledge of reservoir properties, allowing them to reduce risk at every stage in the life of their prospects.

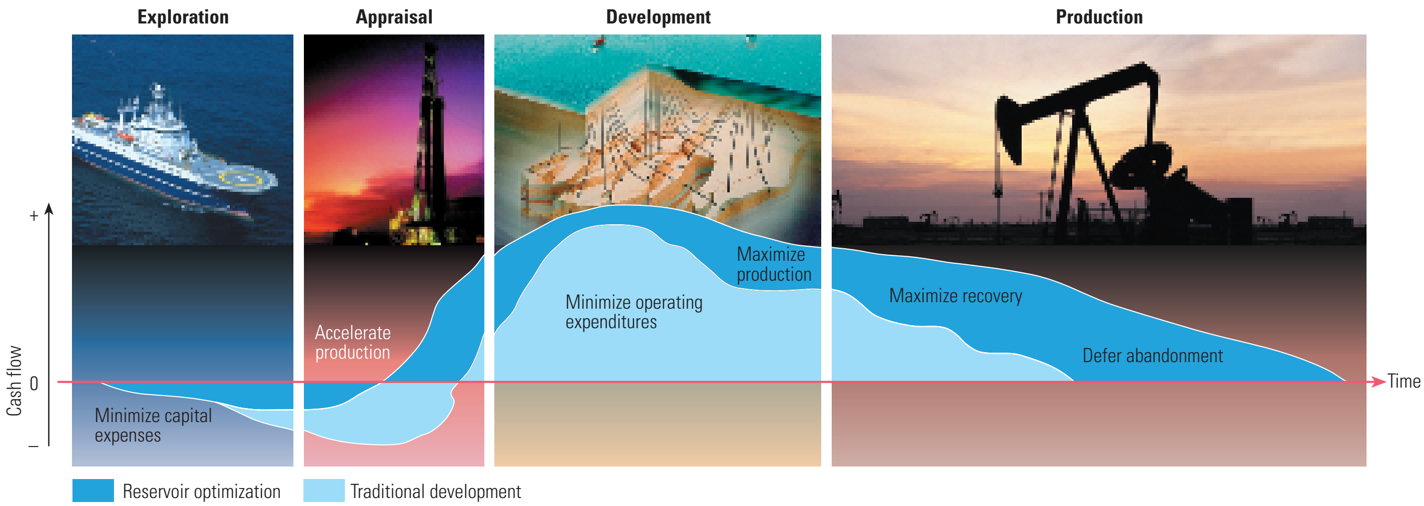
In the last ten years, oil and gas companies have come to consider the three-dimensional (3D) seismic survey an indispensable exploration tool. Investments in seismic acquisition, processing and interpretation have delivered crucial information about reservoir locations and structures. Now, many companies are finding ways to gain more from their seismic data by looking beyond exploration—to extract additional information that will allow them to appraise their reserves with more certainty, more efficiently develop their discoveries, and produce oil and gas more cost-effectively.

Seismic data can enhance asset value at every stage in the life of the field (next page, top). During the exploration stage, promising prospects are scrutinized in detail. High-resolution surface seismic data help fine-tune a prospect's geological model, improving understanding of the petroleum system, optimizing initial well location selection and supplying information for risk analysis. Appraisal-stage drilling benefits from improved mechanical models founded on seismic data and from seismic-based three-dimensional pressure models to predict the location of subsurface hazards, such as shallow water-flow zones and high formation pore pressures. At the development stage, reservoir properties between wells can be mapped using seismic data calibrated with well information. Geoscientists and engineers use log, core and well-test data to generate seismic-based reservoir descriptions from which to create reservoir models. Later, production teams can use time-lapse (4D) seismic surveys to track saturation and pressure changes for better placement of infill wells and extension of field life.

Operating companies capitalize on the technological advances made in both acquisition and processing of seismic data to improve the performance of their oil and gas assets from discovery all the way to abandonment. In this article, we demonstrate how seismic methods are meeting the demands of operators of all sizes, for all stages of field life. Case studies illustrate the many uses of seismic data beyond exploration, highlighting applications that are tailor-made for the reservoir.

Reducing Risk, Improving Economics

During the exploration stage, 3D seismic data help operating companies define the promise of a prospect and the optimal approach to evaluate it. At this point in the prospect's life cycle, seismic data may be the only information available to assess potential reservoirs and to gauge uncertainty and risk before committing the vast capital and resources required for thorough appraisal. During this stage, the drilling, testing and producing of wells provide crucial, more detailed information about the reservoir in the region near the wellbore. As these details are integrated with the seismic data, broader interpretations create new opportunities beyond the well, ultimately reducing risk and improving economics during the field-development stage.

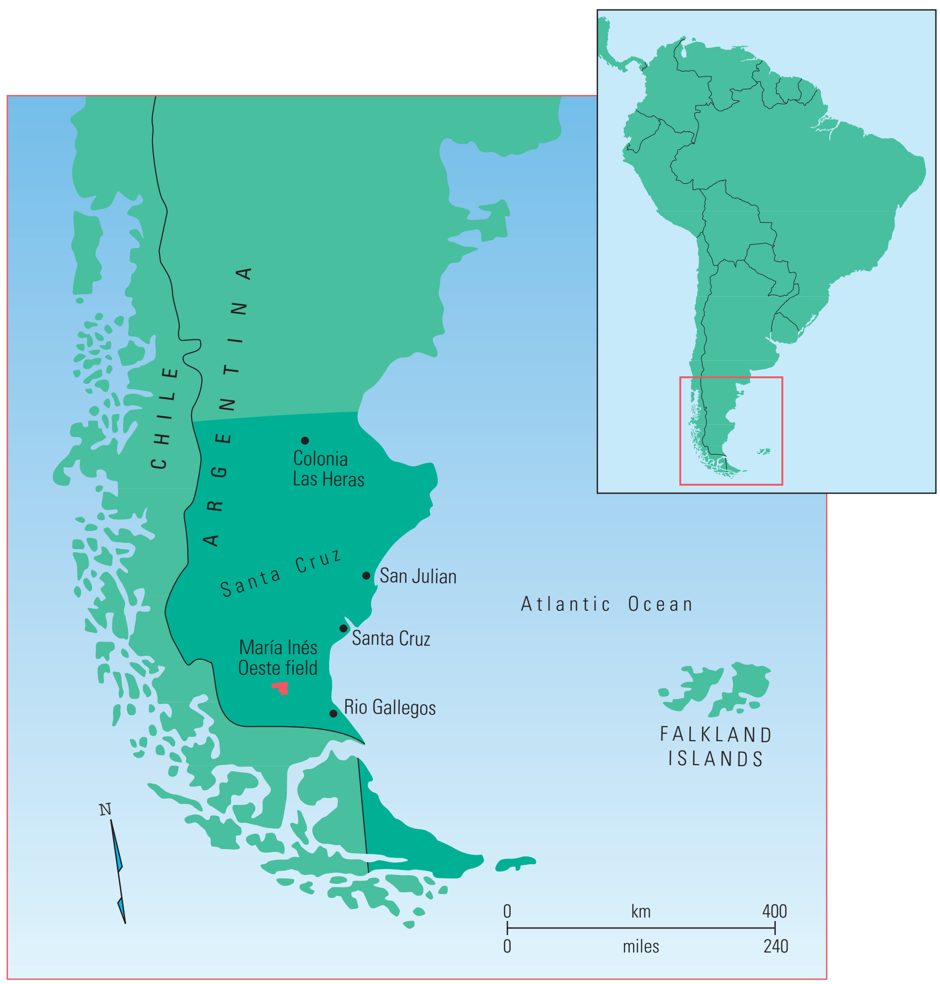


^ Stages in the exploration and production (E&P) life cycle. Through time, oil and gas fields go through four basic stages: exploration, appraisal, development and production. Objectives change as fields mature, impacting expenditures and production and development strategies. Innovative seismic processing and interpretation techniques can help optimize production, enhancing the value of an asset at every stage.

Using this concept, Pecom Energía de Pérez Companc SA (PECOM) and WesternGeco have improved their understanding of the María Inés Oeste field in Santa Cruz, Argentina, laying the foundation for successful appraisal and future development (right). The María Inés sandstone reservoir has an average thickness of 50 m [160 ft], and produces both oil and gas, depending on the well location. The use of qualitative amplitude-variation-with-offset (AVO) techniques has helped define where to drill, but has also led to noncommercial wells drilled in "bright spots."[1]

Geophysicists use AVO techniques to assess thickness, porosity, density, velocity, lithology and fluid content of rocks by exploiting the variation in seismic reflection amplitude with change in distance between shotpoint and receiver. Successful AVO analysis requires special processing of seismic data and seismic modeling to determine rock properties with a known fluid content. With that knowledge, it is possible to model seismic response to other types of fluid content. Standard AVO analyses yield answers that are qualitative rather than quantitative, making it difficult to integrate AVO results into models.

1. Qualitative AVO techniques were developed to understand the relationship between hydrocarbon occurrence and bright spots, or high-amplitude reflections.
   Chiburis E, Franck C, Leaney S, McHugo S and Skidmore C: "Hydrocarbon Detection With AVO," *Oilfield Review* 5, no. 1 (January 1993): 42–50.

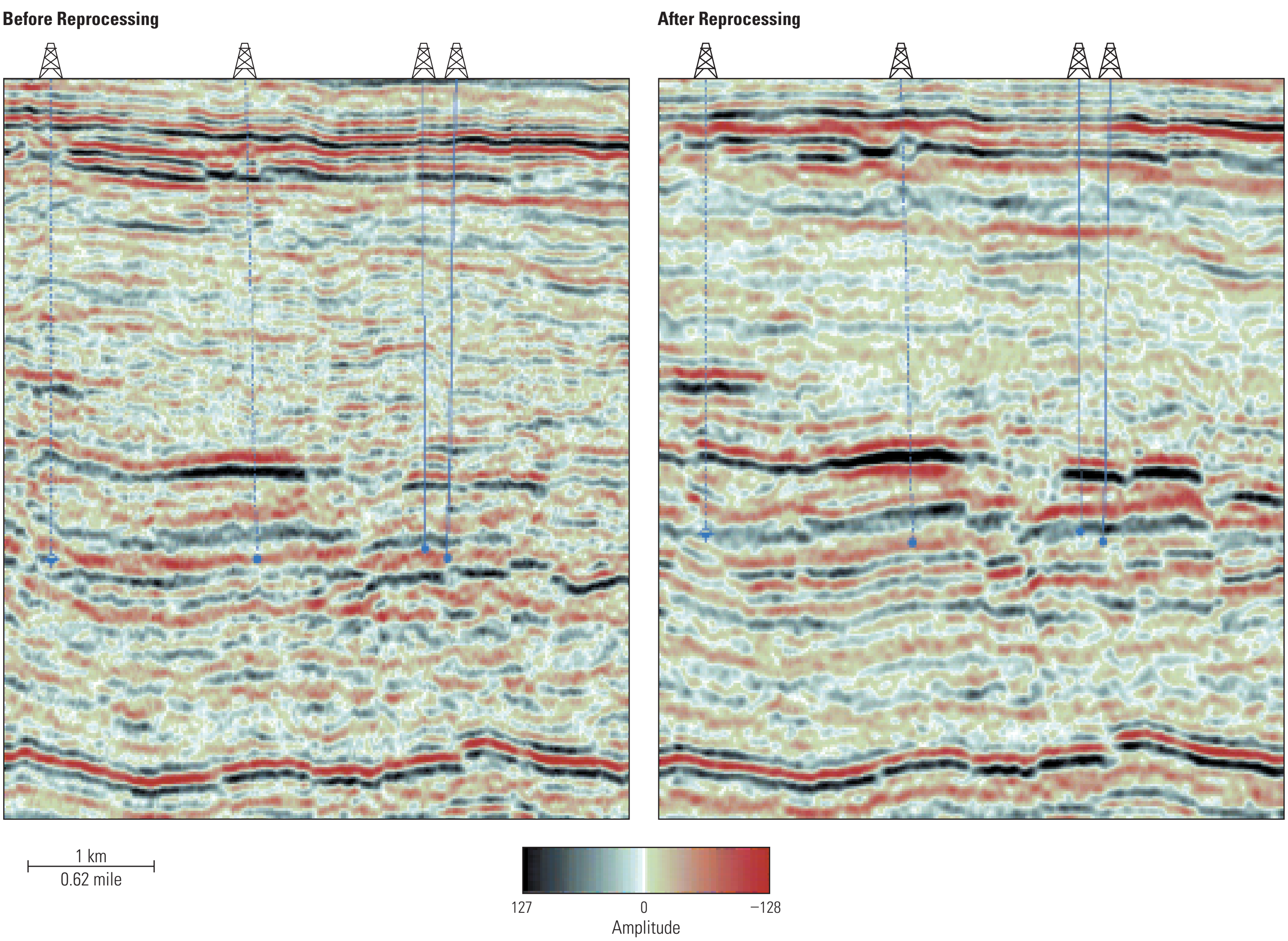


^ Location of the María Inés Oeste field in Santa Cruz, Argentina.

^ Seismic operations in María Inés Oeste field in Santa Cruz, Argentina. Seismic crews and equipment faced a wide range of weather conditions during the data-acquisition process.

The María Inés 3D seismic survey was recorded between November 1995 and February 1996, covering an area of 258 km^2 [100 sq miles] with 33 source lines. The seismic source was a vibrating platform (left). Successful development of the María Inés Oeste field required higher volume wells at reduced risk, so an innovative technique was needed to reduce the uncertainty associated with drilling new wells.[2]

PECOM looked to the Seismic Reservoir Services (SRS) group at WesternGeco to find a more reliable way to use existing seismic data to differentiate between productive and nonproductive areas of the field. Crucial steps taken while reprocessing field data attenuated noise—for example, data spikes and ground roll—and compensated for source, receiver and offset-amplitude variations while preserving the relative-amplitude information in the data. These steps improved the image quality substantially (below). Structural features, such as faults, were



^ Seismic section before and after reprocessing steps. Compared with the original seismic section (*left*), the reprocessed seismic section (*right*) more clearly defined faults and showed improved event continuity at the targets.

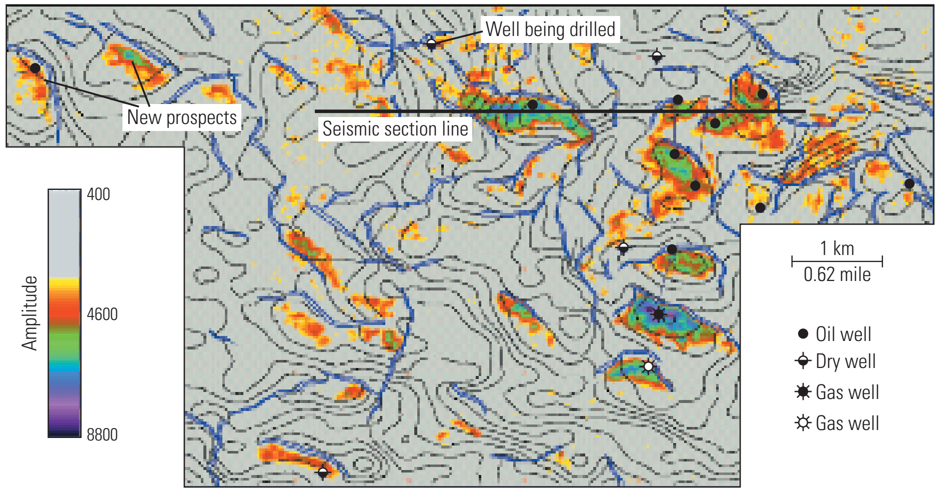
more clearly defined. In the areas of interest, the overall frequency content improved, yielding higher resolution images than the original seismic images. The high quality of the reprocessed data was critical for the successful prestack seismic-inversion process and AVO analysis.[3]

An innovative, hybrid seismic-inversion technique was used during data reprocessing. This technique, which combines prestack waveform inversion, AVO analysis and poststack inversion, was applied to an area of 50 km^2 [19 sq miles] within the field. Hybrid inversion is less computer-intensive than standard prestack waveform inversion so large seismic data volumes can be processed with excellent results.[4] Stand-alone AVO analysis is generally considered a qualitative tool but can be quantitative when tied, or calibrated, to actual well data.

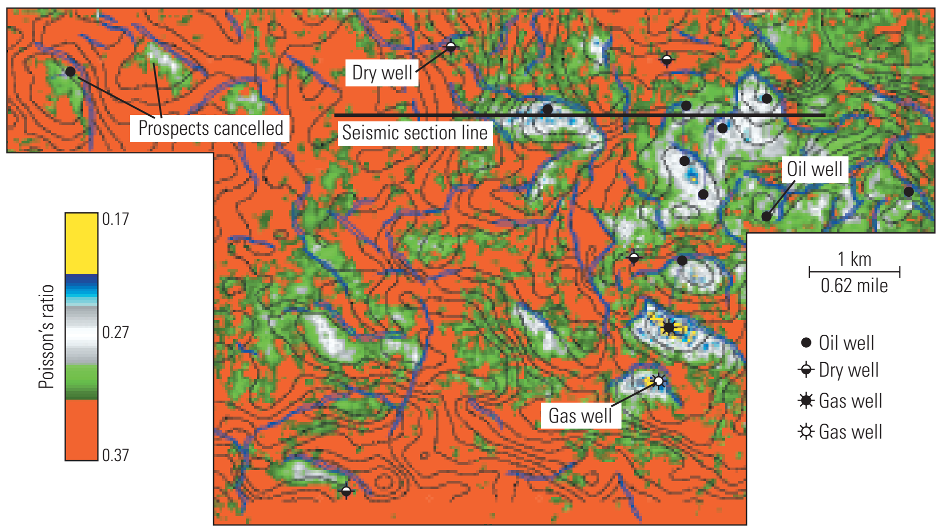
Within the 50-km^2 area, 15 previously drilled well locations were selected based on high-amplitude bright spots demonstrating structural closure. A new well was being drilled at the time of the project, so its location also had been selected without the benefit of the new hybrid-inversion technique. An amplitude map of the migrated compressional data showed the anomalous regions that formed the basis of the well-location selection (above right). The amplitude map confirmed the selection of all the existing well locations, and suggested that the well being drilled would penetrate commercial amounts of hydrocarbons in the María Inés sandstones. The amplitude analysis also suggested potentially productive prospects in the northwest.

Compressional- (P) and shear- (S) wave impedance values from inversion work also were mapped. The P-wave impedance map was similar to the amplitude map and identified the same areas of potential production. The S-wave impedance map appeared featureless and was of little use by itself. However, when the two data sets were analyzed jointly to form an attribute reflecting the Poisson's ratio of the reservoir, a more accurate depiction of the fluid content resulted. Rather than using standard AVO analysis, the hybrid-inversion process, which was tied to well data, produced a more accurate Poisson's ratio interpretation from which to select well locations.

Poisson's ratio varies with lithology, porosity and fluid content. For example, the ratio range for shales is 0.30 to 0.40; for water-bearing sandstones, 0.25 to 0.30; for oil-bearing sandstones, 0.20 to 0.25; and for gas-bearing sandstones, 0.10 to 0.18.[5] When reservoir lithology is constant, information on Poisson's ratio can differentiate between oil, gas and water in the formation.



^ Amplitude map in the María Inés sandstones. The amplitude map of the stacked data confirmed that existing productive wells were in regions of anomalous response. This interpretation indicates that the new well being drilled at the time of the project should be productive and suggests new prospects in the northwest.



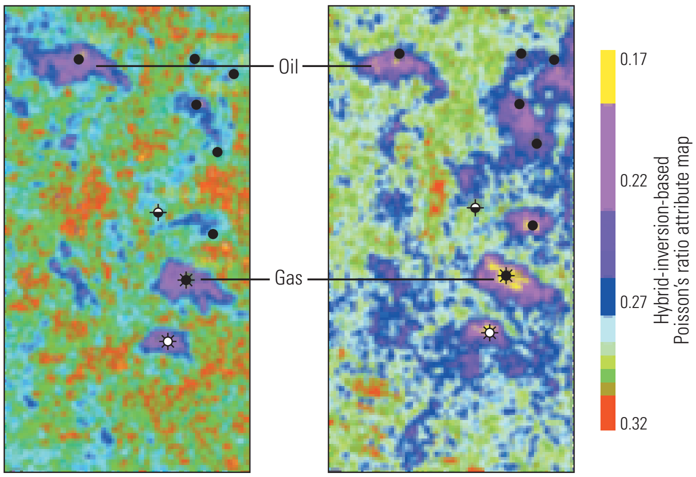
^ Poisson's ratio map. P- and S-wave data were analyzed jointly to form an attribute representing the Poisson's ratio of the reservoir. Poisson's ratio varies with lithology, porosity and fluid content. The variations in Poisson's ratio displayed in this map helped explain why the newly drilled well was nonproductive and caused PECOM to reconsider the viability of some new prospects.

The location of the well drilled during the time of the analysis appears less than optimal on the Poisson's ratio map, as borne out by the resulting dry hole. New prospects identified to the west on the amplitude map now look questionable (above). However, one well drilled after the analysis in the most western anomaly, produced oil for a short time but then produced water. Consequently, both prospects to the west were cancelled. The Poisson's ratio map using the hybrid-inversion data enabled the drilling of

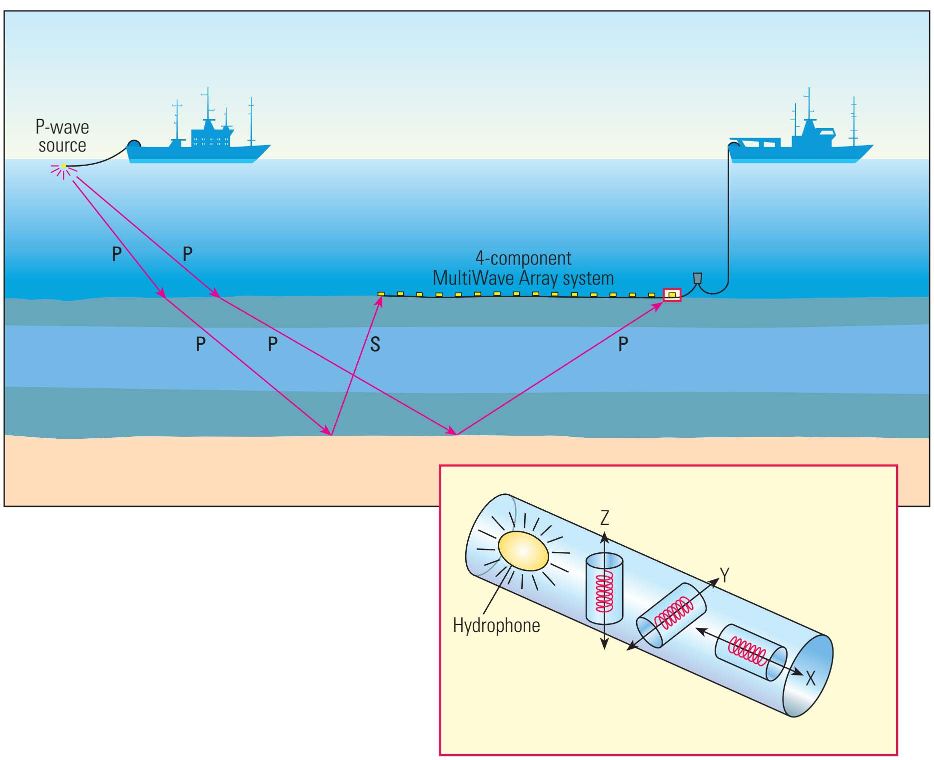
2. Benabentos M, Sigismondi M, Mallick S and Soldo J: "Seismic Reservoir Description Using Hybrid Seismic Inversion: A 3-D Case Study From the María Inés Oeste Field, Argentina," submitted for publication in *The Leading Edge* 21, no. 10 (October 2002).
3. Mallick S: "Some Practical Aspects of Prestack Waveform Inversion Using a Genetic Algorithm: An Example from East Texas Woodbine Gas Sand," *Geophysics* 64, no. 2 (March–April 1999): 323–349.
4. Mallick S, Huang X, Lauve J and Ahmad R: "Hybrid Seismic Inversion: A Reconnaissance Tool for Deepwater Exploration," *The Leading Edge* 19, no.11 (November 2000): 1230–1237.
5. Mavko G, Mukerji T and Dvorkin J: *The Rock Physics Handbook: Tools for Seismic Analysis in Porous Media*. New York, New York, USA: Cambridge University Press, 1998.

two productive wells—one gas well to the southeast and one oil well to the northeast—in the project area.

Maps of reflection amplitude and of Poisson's ratio derived from standard AVO analysis were not able to distinguish clearly those areas where the María Inés sandstones contain oil and those that contain gas, while the hybrid-inversion-based attributes did so without ambiguities (below). This was demonstrated most clearly in the southeast portion of the project area. Improved understanding of reservoir-fluid content helped optimize well locations, reducing cost and risk while draining the reservoir more efficiently.



^ Comparison of attribute maps of the southeast portion of the study area. Amplitude mapping (*left*) did not distinguish clearly between oil and gas (labeled), while the hybrid-inversion-based Poisson's ratio attribute map did so without ambiguity (*right*).



^ Multicomponent data acquisition. A seismic-recording cable is positioned directly on the seafloor to mechanically couple the receivers to the earth. Each sensor station contains a hydrophone that records compressional-wave (P-wave) data and geophones that record particle motion in three orthogonal directions—X, Y and Z (*inset*).

In addition to reducing the risk associated with development drilling, the hybrid-inversion study by SRS had a positive impact on field economics. An economic analysis completed by PECOM compared the recoverable reserves before and after using the new technique. PECOM estimates that 35% of the technically recoverable reserves could be developed commercially at an oil price of $12 per barrel. Based on this estimate, before the reprocessing and hybrid-inversion techniques, the net present value of production was estimated to be $230 million, compared with a value of $270 million after the reprocessing and hybrid-inversion techniques. An economic impact of $40 million dollars is attributable to improved understanding of project risks and reduced uncertainties.

Multicomponent Seismic Data for Reservoir Definition

Another example of the use of seismic data for reservoir appraisal comes from the central North Sea, where Conoco is active in their assessment of the Callanish field. The field was discovered in 1999 and confirmed by an appraisal well in 2000. The main productive interval, the Forties sandstone, is a complex Tertiary reservoir controlled by both structural and stratigraphic trapping mechanisms and contains oil, gas and water. The geophysical challenges in this area are twofold—identifying lithology and fluid content within the Tertiary strata.

The observed acoustic-impedance contrast is extremely low between the hydrocarbon-bearing Forties sandstone and the overlying shales. As a result, conventional compressional-wave, or P-wave, data often cannot distinguish between shale and productive reservoir containing hydrocarbons because both appear as diminished reflections. This makes delineating the reservoir very difficult. In the Forties sandstone, the potential for structural and stratigraphic discontinuities further complicates matters. When geophysicists and geologists cannot adequately differentiate sand from shale on seismic images, determining where sands pinch out or are truncated by faults is difficult. Furthermore, any amount of gas in the reservoir or overburden disrupts P-wave transmission, creating poor-quality images below gas zones.

In a project carried out by Conoco and the SRS group at WesternGeco, multicomponent (4C) marine seismic technology was deployed to overcome the difficulties associated with imaging in this complex environment.[6] Because shear (S) waves do not propagate through water, towed streamers cannot record them. Instead, a seismic-recording cable is positioned directly on the seafloor to mechanically couple the receivers to the earth. Each sensor station contains a hydrophone that records P-wave data and geophones that record particle motion in three orthogonal directions—Z, X and Y (previous page, bottom).

The Z-component geophone records particle motion in the vertical direction, responding primarily to P waves. The X- and Y-component geophones record particle motion in orthogonal horizontal directions and respond predominantly to S-wave movements. Four-component data yield more reliable estimates of compressional-wave velocity to shear-wave velocity ratio (V_p/V_s) and potentially provide information on formation density. The ability to record multicomponent data in the marine environment enables geophysicists to solve complex imaging problems, helping to bring the reservoir into sharper focus.

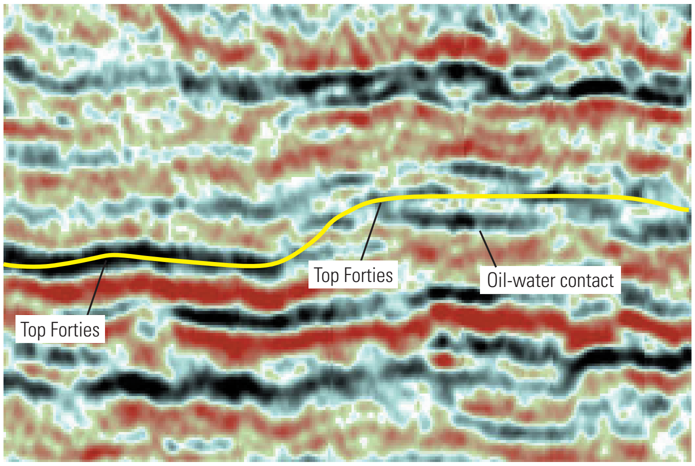
In the case of the Callanish field, data, including porosity, permeability, acoustic properties, water saturation and shale volume, from four nearby wells were assessed initially to understand the reservoir at the wellbore. This characterization was beneficial in modeling, defining the different horizons to enhance the image quality of the reservoir.

While the summed hydrophone and vertical-component geophone data (PZ data) from the Callanish 4C survey produced higher quality images than the conventional towed-streamer data, the low acoustic-impedance contrast between the shale and the hydrocarbon-bearing Forties sandstone still caused problems. These ambiguities increase risk during the appraisal process because it is difficult to avoid nonproductive intervals when selecting well locations. The S-wave signals, because they are unaffected by the formation-fluid content, clearly identified the lithological contrast at the top of the Forties reservoir, while the PZ data detected the oil-water contact below the top of the reservoir (above right). Both data types proved useful in identifying brine-filled areas in the Forties sandstone.

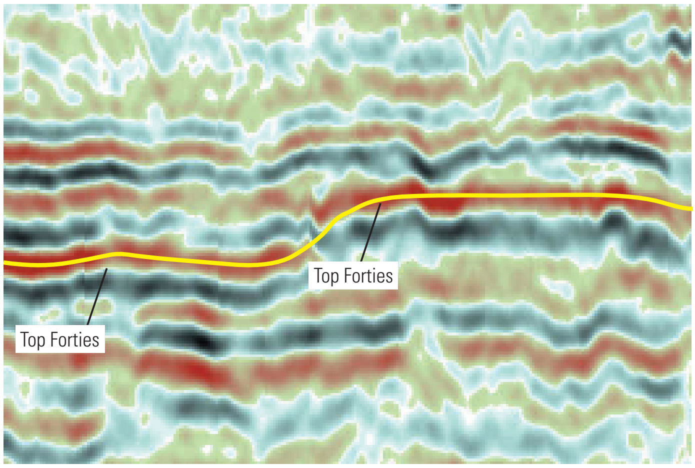
Attribute maps from shear-wave data can help resolve complexities in a field. In the Callanish field, acoustic-impedance mapping of the reservoir top shows the depositional trend, but does not allow the differentiation between shale and hydrocarbon-filled sandstone (right).

6. Caldwell J, Christie P, Engelmark F, McHugo S, Özdemir H, Kristiansen P and MacLeod M: "Shear Waves Shine Brightly," *Oilfield Review* 11, no. 1 (Spring 1999): 2–15.

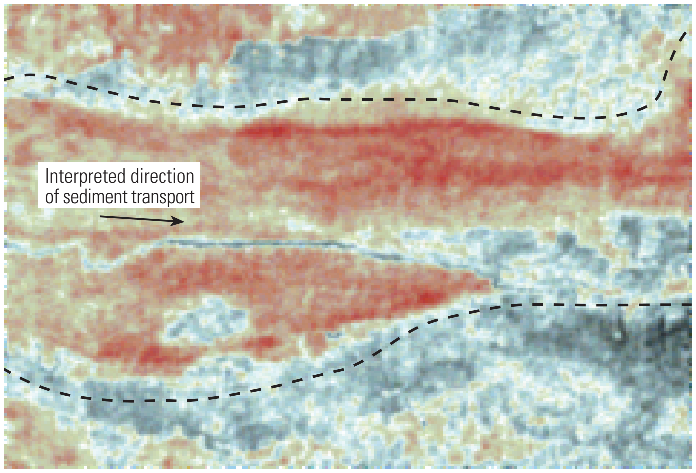
PZ Data



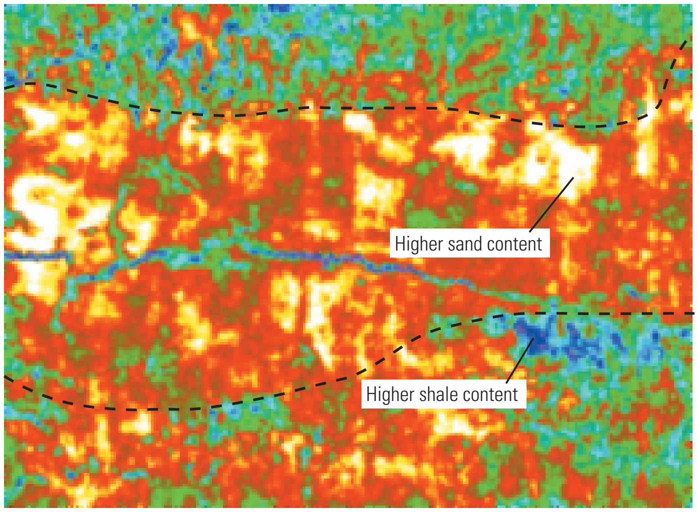
S-Wave Data



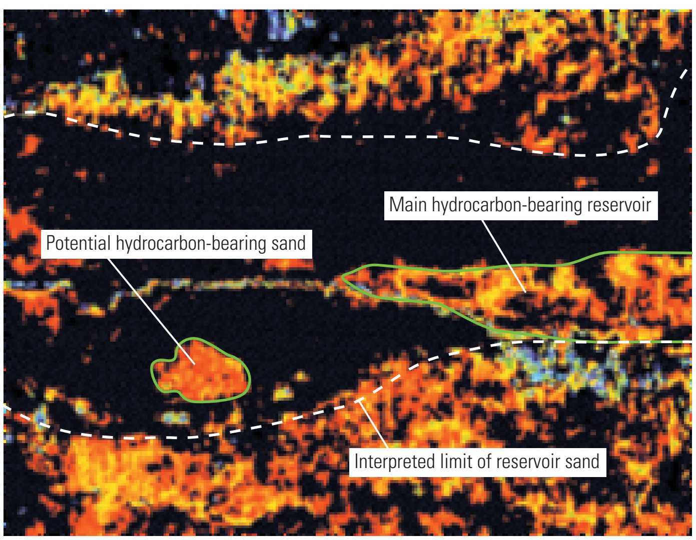
^ Resolving seismic image ambiguities with multiple-component data. The S-wave signals (*bottom*), unaffected by formation-fluid content, identify the lithological contrast at the top of the Forties reservoir (yellow), while the summed hydrophone and Z-component compressional data (PZ data) detected the oil-water contact below the top of the reservoir (*top*).



^ Acoustic-impedance map on the top of the Forties reservoir in the Callanish field. The map shows the depositional trend, but the shale outside the depositional limits of the sand (dashed lines) cannot be differentiated from the possible hydrocarbon accumulations.



^ Shear-amplitude map of the top of the Forties reservoir. When shear-amplitude data are used, an attribute map of shear-reflection amplitude, R_{ss}, identifies lithology by distinguishing shale from productive reservoir. White and yellow indicate higher sand content and blue indicates higher shale content. R_{ss} is derived from the compressional-to-shear reflection amplitude, R_{ps}. The depositional limit of the sand is defined by the dashed line.



^ Attribute map of the ratio of the compressional-reflection amplitude to shear-reflection amplitude, R_{pp}/R_{ss}. The R_{pp}/R_{ss} ratio map reveals both lithology and fluid content. In this case, the map identifies hydrocarbon-bearing reservoir within the area of sand deposition (dashed line).

A better understanding emerges when shear data are examined. An attribute map of shear-reflection amplitude (R_{ss}), derived from the mode-converted, compressional-to-shear reflection amplitude (R_{ps}), identifies lithology by distinguishing shale from productive reservoir (left). Taking the process one step further allows the mapping of an attribute that more adequately describes the lithologic and fluid characteristics of the reservoir. Similar to Poisson's ratio, a ratio of the compressional-reflection amplitude, R_{pp}, to R_{ss}, written as R_{pp}/R_{ss}, reveals both lithology and fluid content (below left).

Oil and gas companies use this 4C analysis to design well locations and trajectories optimally, contacting more reserves, while reducing risk during the appraisal stage. Integration of new-well data with the existing 4C seismic data further reduces risk in the future development of fields such as Callanish.

Seismic-Based Hazard Prediction

The oil industry spends $20 billion annually on drilling operations. Of that amount, about $3 billion is attributable to losses. Drillpipe, fluids, rig time, large-scale capital assets and human life all are at risk. One major cause of loss is unexpected, abnormally high formation pressure, sometimes called a geohazard. As exploration extends to deeper oil and gas targets, drilling engineers must understand the pressure environments to properly place casing points, since even one misplaced casing point may result in failure to reach target depth.

Predrill assessment of geohazards has therefore become an essential component of well planning. When compared with the costs directly related to drilling operations—in some cases approaching $500,000 per day—the cost of hazard prediction is minor. No offshore well is drilled without such a hazard assessment.

High-quality seismic data hold the key to accurate predrilling predictions of fluid pressure. The behavior of rock velocities with depth reveals a great deal about the state of pore pressure that can be expected in the subsurface.

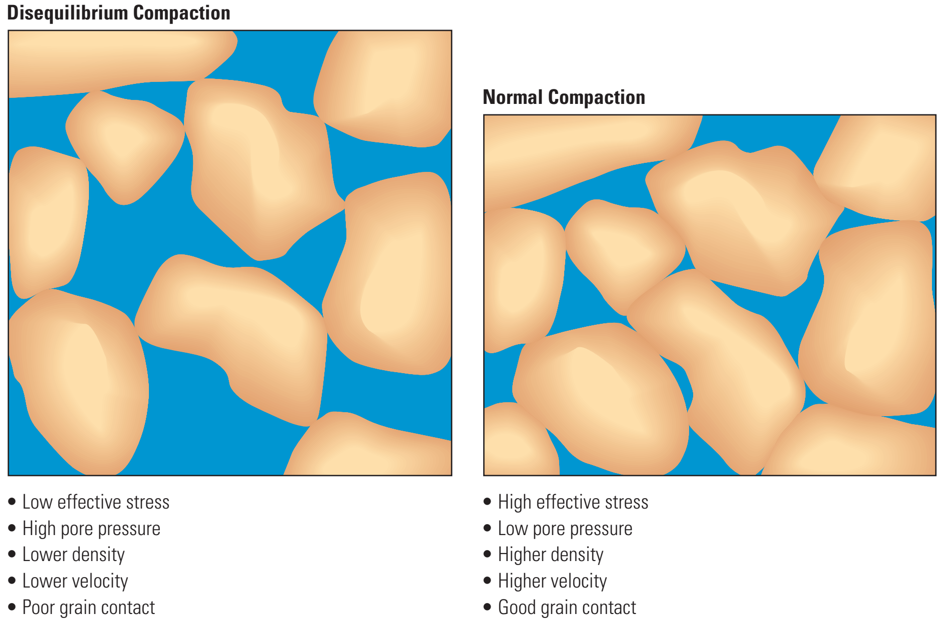
Pore pressures that are greater than hydrostatic pressure, or the weight of a column of water, are called overpressured. Overpressure is caused primarily by a phenomenon referred to as disequilibrium compaction (next page, top).[7] At low rates of deposition, rock grains settle, and pore volume decreases as water is expelled. Rapid deposition of fine-grained sediments prevents escape of water from the sediment volume, keeping pore volume high. When water remains within sediment that then is buried, the weight of the overlying mass is supported not only by grain-to-grain contact but also, in part, by the water trapped in pore spaces.

Drilling into unanticipated, overpressured, permeable sands or carbonates has caused major losses of well control. Overpressure in comparatively impermeable shales raises many wellbore-stability issues. The SRS group currently offers the oil and gas industry proprietary approaches to assess the likelihood and degree of overpressure in different environments (below right).

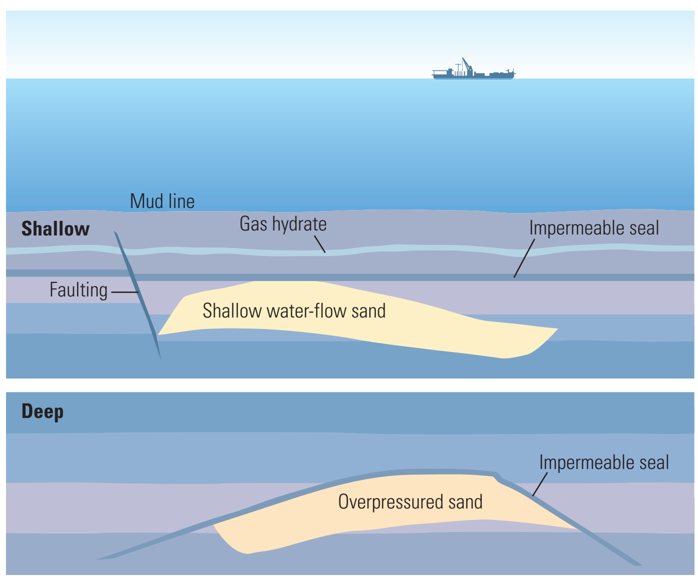
Shallow water flow—Shallow water flow is a condition occurring typically in deep water—depths in excess of 1500 ft [460 m]—and in sediments buried at least 1200 ft [365 m] beneath the seabed. It is called shallow because it occurs in the strata relatively near the seabed. Submarine fans and turbidite flows can deposit large amounts of sediment rapidly. Sand bodies encased within finer grained, low-permeability muds remain unconsolidated and become overpressured. Drill-bit penetration of such a sand results in fluid loss and rapid extrusion of a sand slurry up the borehole onto the seabed. Drillpipe can become stuck or bent, causing complete loss of the hole.

WesternGeco follows a five-step process to identify potential shallow water-flow sands. Since each study depends on a true-amplitude, high-frequency broadband seismic signal, the suitability of the data-processing flow is assessed. Next, a stratigraphic interpretation is conducted to identify depositional facies and environments. Third, an AVO analysis is performed to extract the compressional-wave intercept and gradient volumes. A weighted combination of the two yields a pseudo-S-wave volume. Fourth, a WesternGeco proprietary application called full-waveform prestack seismic inversion employs a genetic algorithm (GA) methodology to forward model an observed seismic angle gather and invert elastic-rock properties such as V_p, V_s, density and Poisson's ratio. Finally, the low-frequency trend from the 1D prestack inversions constrains a hybrid inversion—a combination of the prestack inversion with a poststack inversion—to V_p and V_s volumes, which are then divided to yield a V_p/V_s volume.

7. Other causes of geopressure are tectonic compression, aquathermal expansion, smectite dehydration of absorbed and adsorbed water, smectite to illite diagenesis and hydrocarbon formation. Of these, tectonic compression is thought to be the most significant.



^ Pore-pressure effects on rock properties. The major cause of geopressure (pressure above hydrostatic) is disequilibrium compaction. When rock grains are deposited, they pack loosely, leading to very high initial porosity and poor grain-to-grain contact (*left*). The overburden weight is supported both by the grains, through grain-to-grain contact, and by the pore fluid. As overburden weight increases, the formation compacts and expels water, reducing porosity and improving grain-to-grain contact (*right*). When the overburden weight increases too quickly, more of the weight is supported by the fluid, resulting in high pore pressure.



^ Types of geohazards. Shallow hazards (*top*) are common in deepwater environments where high-pressure sands present drilling hazards because of their uncompacted state. Pore volume is so high that the sand itself is more like a slurry. If overlain by less permeable shales, pore water cannot escape and pore pressure increases. When a drill bit penetrates such a formation, sand can flow out of the borehole and may bend drillpipe in the process. Drilling-mud weights must be monitored closely as separation between the fracture gradient and pore pressure will be very small. Deep hazards (*bottom*) occur in deeply buried, more consolidated sediment that contains overpressured fluids. In this situation, there is usually more separation between fracture- and pore-pressure gradients.

A high V_p/V_s ratio can be characteristic of shallow water-flow sands because the ratio theoretically approaches infinity as the sediments become more fluid. Both V_p and V_s decrease with increasing fluidity, but V_s decreases much faster, reaching zero in water. When a high V_p/V_s ratio is located near an appropriate stratigraphic sequence, such as beneath a rapidly deposited turbidite flow, the likelihood of a drilling hazard increases (below left).[8]

Apache Corporation commissioned WesternGeco to provide a shallow water-flow study on a deepwater prospect in the Mediterranean Sea. Apache elected to move a well location that initially had been placed to penetrate a shallow fingered submarine fan complex showing a high possibility of shallow, overpressured, unconsolidated sands. The relocated well proved to be a new field discovery for Apache and was drilled without encountering shallow hazards.

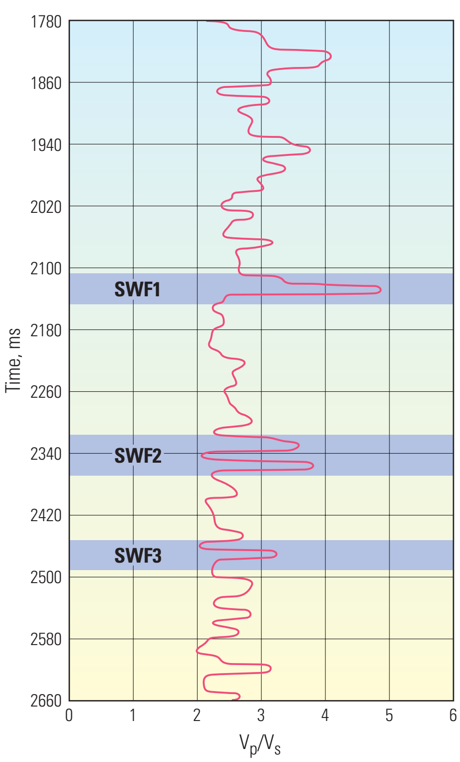
Deep pore pressure—At today's drilling depths, overpressure can reach twice that of hydrostatic pressure. To assess the drilling hazards presented by high-pressure environments and help design casing programs, the industry is turning to WesternGeco for predrill pressure predictions.[9]

WesternGeco uses a proprietary rock model that accounts for disequilibrium compaction and shale diagenesis (below right).[10] Velocity information is extracted from seismic data, and through a series of inversion steps, porosity and density information are obtained. From seismic-derived density, an overburden gradient is computed. Other computed curves display fracture gradient, normal compaction trend, normal effective stress and effective stress—pressure between grain-to-grain contacts.[11] Finally, pore pressure is computed using Terzaghi's principle, which states that overburden is equal to pore pressure plus effective stress.[12]

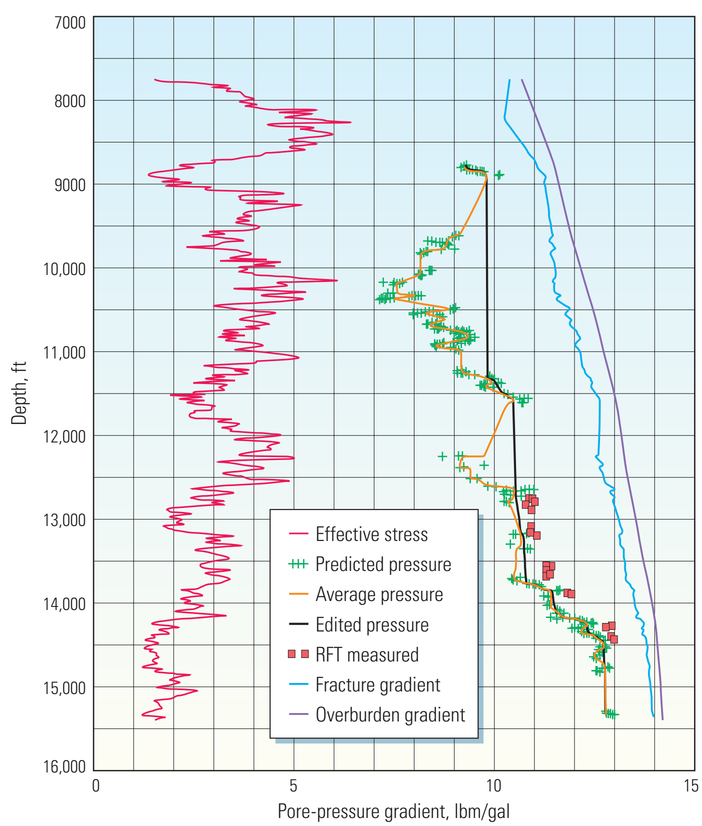
The WesternGeco approach to pore-pressure prediction produces a pressure profile that can be accurate to within one half of a pound per gallon (lbm/gal) of mud weight. This can be achieved even in the absence of offset-well calibration information. High-quality seismic data are the key, together with velocity-inversion methods, such as prestack depth-migration tomography, which deliver physically meaningful velocities.[13]

On a prospect in the North Sea, WesternGeco provided Amerada Hess with a pore-pressure prediction for a deep sub-Cretaceous chalk reservoir. Establishing this prediction was challenging because the objective was in an older pre-Tertiary section with interbedded carbonates and carbonate-cemented clastic sediments above. Velocity corrections for shale anisotropy had to be taken into account.

The predrill mud-weight prediction of 16 lbm/gal [1920 kg/m^3] was supported using a zero-offset vertical seismic profile (VSP) to perform a pseudoreal-time update of pressures and to forecast ahead of the bit. Mud weights in the well reached 16 lbm/gal and ramped up to 17 lbm/gal [2040 kg/m^3]. Drilling was completed successfully, under control to total depth.



^ Anomalously high V_p/V_s ratios indicating three shallow water-flow (SWF) hazards. As rapid deposition of low-permeability shales buries more permeable sands, the expulsion of pore water is inhibited. Consequently, V_p remains low, but V_s remains close to zero since fluids cannot support shear waves.



^ Deep pore-pressure prediction. This pressure prediction was based on seismic data only, without calibration-well information. The predicted pressure (green crosshatches) was within 0.5 lbm/gal mud weight of post-drill RFT Repeat Formation Tester pressure measurements (red squares). At a depth of 14,500 ft, pore pressure is within 1 lbm/gal mud weight of the fracture gradient.

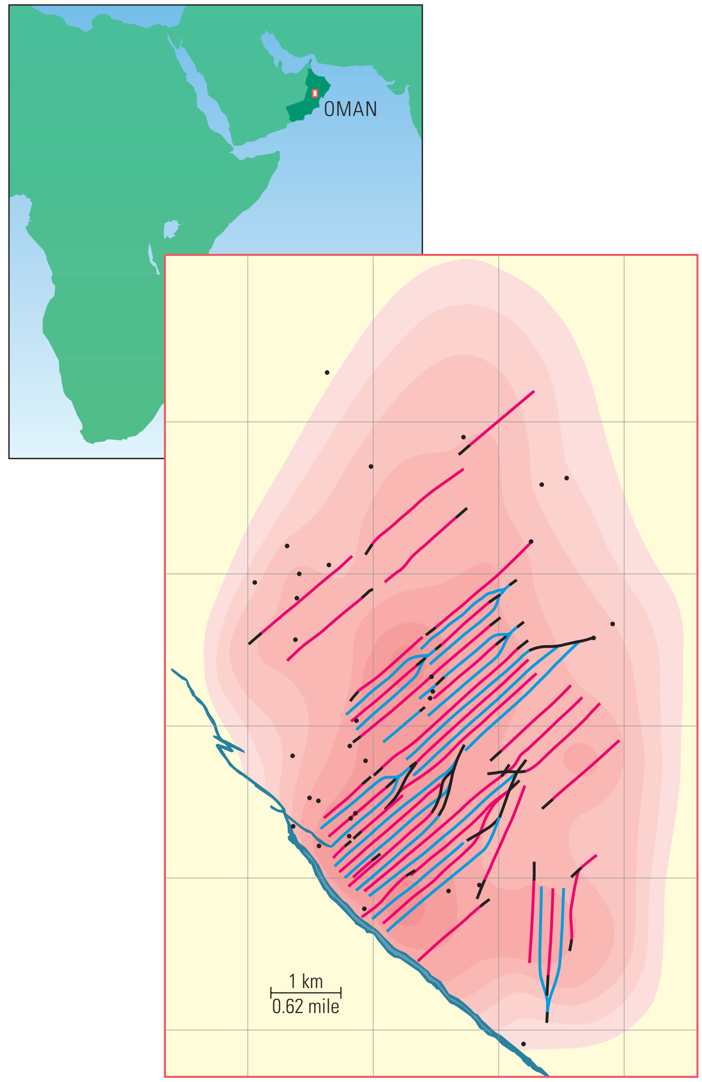
3D Seismic Characterization

Once a prospect has been appraised, crucial development decisions may reduce the uncertainty and associated risk in future phases in the exploration and production (E&P) life cycle. Confidence in reservoir models derived solely from standard well data tends to be highest near wellbores, and it usually decreases sharply away from well control. To help characterize the reservoir between wells and better exploit its potential reserves, companies now rely upon the improved spatial resolution of modern seismic data to extend their reservoir models into undrilled areas of existing fields. While this can be a significant challenge even in siliciclastic reservoirs, carbonate reservoirs present additional challenges.[14]

The Cretaceous Shuaiba formation in central Oman exhibits many common characteristics of carbonate reservoirs (right). Such reservoirs are typically heterogeneous with complicated permeability and porosity networks. Often they are naturally fractured, posing significant challenges in reservoir modeling. In one example, the Shuaiba formation maintains an average thickness of 60 m [200 ft], displays low permeability, between 1 and 7 mD, but high porosity, between 10 and 35%. The field itself comprises a low-relief dome bounded to the southwest by a near-vertical fault.

Given this complexity, WesternGeco and Petroleum Development Oman (PDO) recently conducted a reservoir study to generate an optimal reservoir model for reserves forecasting, dynamic-flow simulation and infill-well planning.

To accomplish this, a detailed 3D model was constructed by integrating a reprocessed 3D seismic-amplitude volume with log data from 40 multilateral wells and 29 vertical wells, four of which have core data. The top surface of the Shuaiba reservoir was mapped using formation tops from well logs and traveltime plus velocity information from seismic data. Fine-scale stratigraphic grids, or layers, were constructed spanning six defined reservoir zones, into which the log data were resampled. By following the grid-block resampled log data, the spatial trends in porosity and water saturation were established by 3D-variogram analysis.[15] Directional 3D variograms were constructed at arbitrary azimuths and dips, both parallel and normal to bedding. A standard geostatistical model was then fitted to each graph, so that the corresponding range in property values could be determined. By fitting an ellipsoid to the locus of these ranges, a 3D model of spatial anisotropy was derived for each reservoir property.



^ Field location in Oman and a structure map of the field showing well trajectories.

8. de Kok R, Dutta N, Khan M and Mallick S: "Deepwater Geohazard Analysis Using Prestack Inversion," *Expanded Abstracts* 2001 SEG International Exposition and 71st Annual Meeting, San Antonio, Texas, USA (September 9–14, 2001): 613–616.
9. Cuvillier G, Edwards S, Johnson G, Plumb D, Sayers C, Denyer G, Mendonça JE, Theuveny B and Vise C: "Solving Deepwater Well-Construction Problems," *Oilfield Review* 12, no. 1 (Spring 2000): 2–17.
10. Dutta NC: "Deepwater Geohazard Prediction Using Prestack Inversion of Large Offset P-Wave Data and Rock Model," *The Leading Edge* 21, no. 2 (February 2002): 193–198.
11. Dutta, reference 10.
12. Terzaghi K: *Theoretical Soil Mechanics*. New York, New York, USA: John Wiley & Sons, 1943.
13. Sayers CM, Woodward MJ and Bartman RC: "Seismic Pore-Pressure Prediction Using Reflection Tomography and 4-C Seismic Data," *The Leading Edge* 21, no. 2 (February 2002): 188–192.
14. Akbar M, Vissapragada B, Alghamdi A, Allen D, Herron M, Carnegie A, Dutta D, Olesen J-R, Chourasiya R, Logan D, Stief D, Netherwood R, Russel SD and Saxena K: "A Snapshot of Carbonate Reservoir Evaluation," *Oilfield Review* 12, no. 4 (Winter 2000/2001): 20–41.
15. A variogram is a two-point statistical function that describes the increasing difference or decreasing correlation, or continuity, between sample values as separation between them increases.

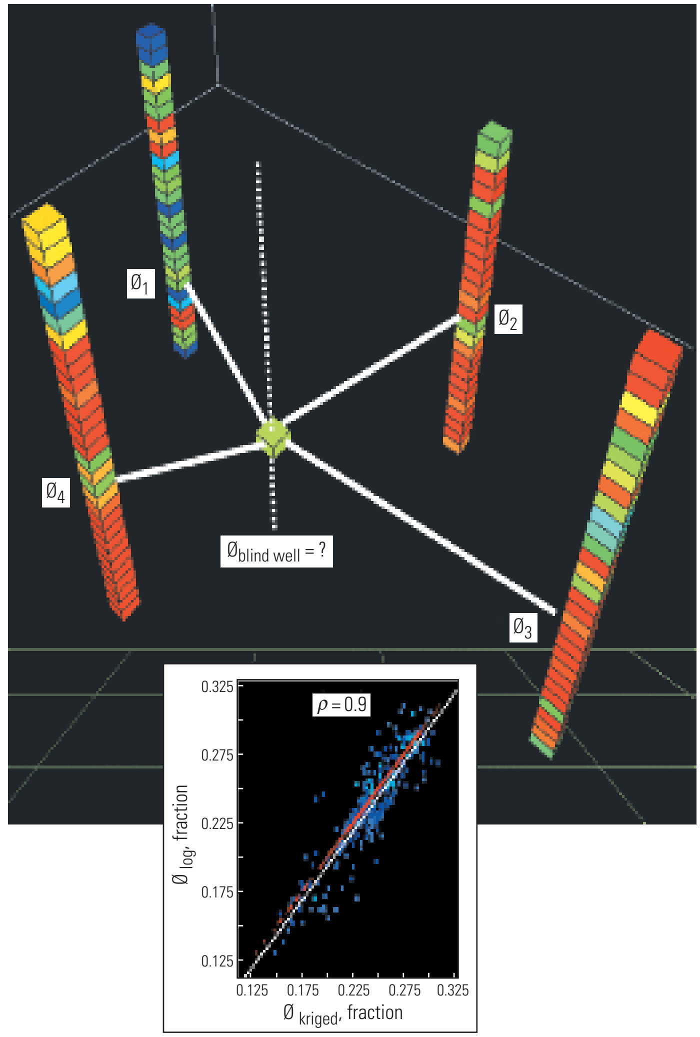
    Isaaks EH and Srivastava RM: *Introduction to Applied Geostatistics.* New York, New York, USA: Oxford University Press, 1989.

Crucial to the modeling process was testing the reliability of modeled predictions against actual well measurements. To identify the seismic attributes best correlated to porosity, comprehensive calibration analysis was performed to ensure that any relationships employed in mapping were both physically meaningful and statistically significant. Next, a cross-validation technique, along with derived spatial correlation models and calibrated seismic attributes, was used to screen various geostatistical approaches for mapping the reservoir properties through each layer. This technique identified trend kriging as an optimal technique for 3D porosity mapping this field.[16] An average vertical-porosity trend—normal to bedding—was derived from the log data and combined with an areal seismic trend, obtained by cokriging of zone-average porosity, and guided by seismic amplitude and the surface defining the top of the Shuaiba reservoir. The resulting 3D trend was used to derive a trend-kriged porosity model by kriging the well-porosity values, providing a more detailed picture of the 3D porosity distribution.

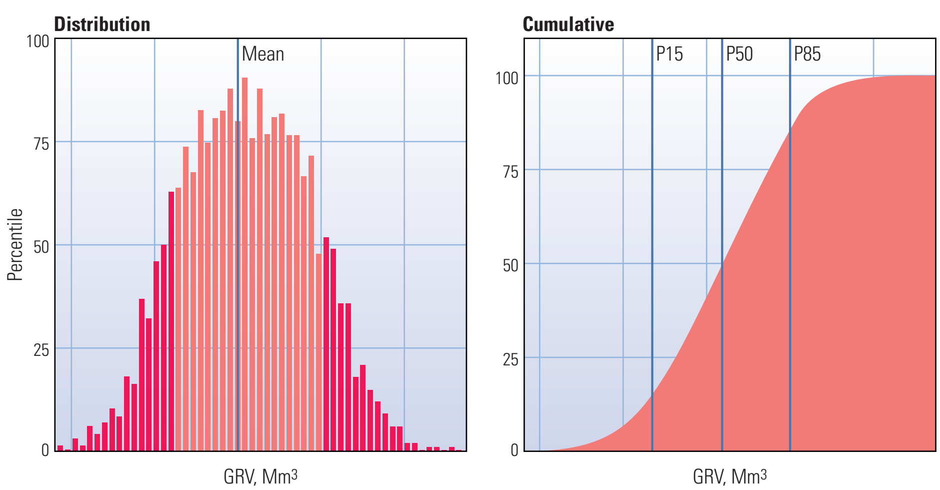
The reliability of the trend-kriged porosity model was quantitatively assessed, using a cross-validation technique (right). In this technique, a porosity model was first computed by trend kriging, excluding a selected "blind well." The trend-kriged porosity at the hidden well was then compared with measured well log values at every depth. The excellent statistical correlation of 0.9 demonstrates the reliability of the trend-kriged porosity model.

Volumetric analyses were performed using the seismic-constrained reservoir model. Stochastic simulation of gross rock volume (GVR) and net pore volume (NPV) was also performed. The primary purpose of this simulation was to assess the impact of structural uncertainty on estimated reserves. Estimates of GRV and NPV were computed, along with the various percentiles—P15, P50 and P85—reflecting the expected impact of structural uncertainty (right).

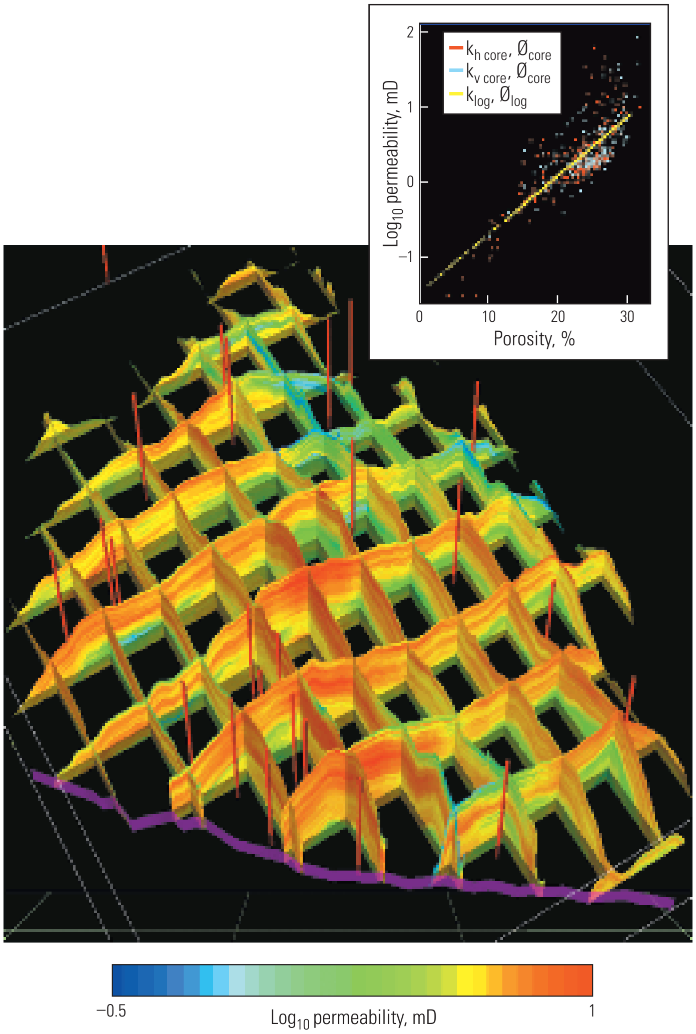
Core-porosity and core-permeability data also were used to establish a porosity-permeability transform. By applying this transform to the trend-kriged porosity, a seismic-constrained permeability model was computed for each reservoir layer to allow flow simulation (next page, top). An oil-saturation model also was derived from trend-kriged porosity, using a lambda-height saturation relationship for each of six porosity classes. The porosity, permeability and saturation models for each reservoir layer were then exported, first to an upscaling program and finally to a simulator for dynamic-flow simulation.



^ Cross-validating the results of a porosity model. A porosity model constructed using trend kriging omitted a central well from the analysis. The model porosity at this "blind well" location was compared at every depth to measured well-log values. The resulting statistical correlation was excellent, validating the trend-kriged porosity model (*inset*).



^ Estimating gross rock volume (GRV) using stochastic methods. The distribution of results of gross rock volume (*left*) and the cumulative result (*right*), reflect the impact of uncertainty in the structure. The P15, P50 and P85 percentiles indicate the spread in result. The actual GRV values are not shown.



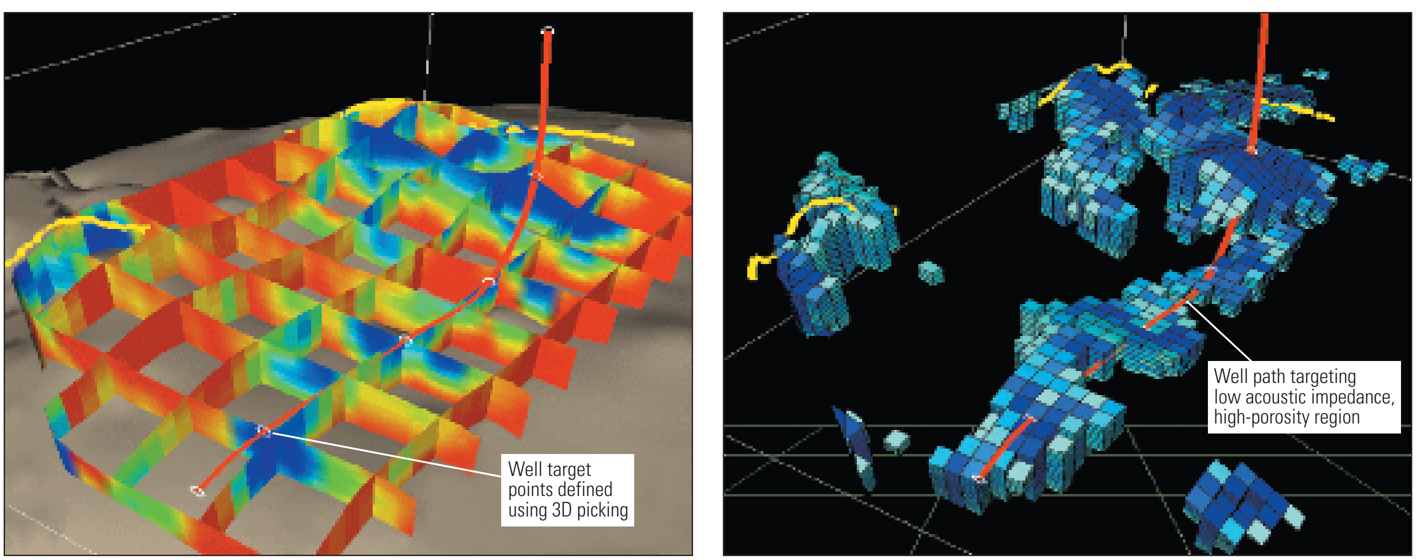
^ Building a seismic-constrained permeability map. The relationship of porosity and permeability from core data (*inset*) provided a porosity-permeability transform. This provides a seismic-constrained permeability model for flow simulation. Vertical red lines identify well locations.

In this example, rigorous integration of the available well data with a high-quality seismic volume yielded an optimized and reliable reservoir model. Confidence in the model was further reinforced by an excellent history match, encouraging PDO to use the model for well planning. Now, wells can be designed to target the highest quality reservoir, optimizing hydrocarbon production and drainage in the Shuaiba formation (below).

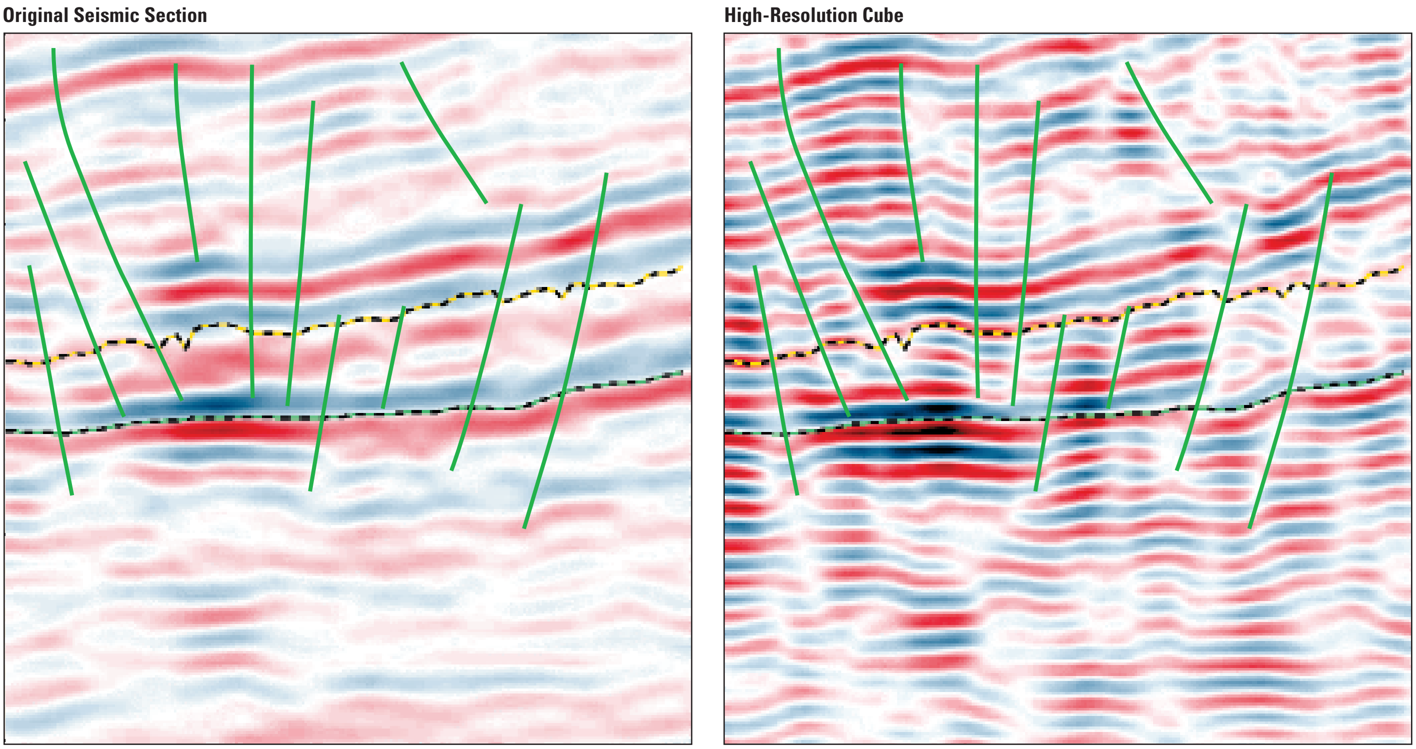
Identifying and Quantifying Subsidence

In the North Sea, companies operating reservoirs that are well into the production stage face unique challenges associated with producing high-porosity reservoirs. The Paleocene Ekofisk and the Cretaceous Tor chalk formations are known for their high porosity, low permeability, low initial water saturations and natural fractures, but also for their extreme compaction tendencies.[17] While compaction is a strong reservoir-drive mechanism in these chalk reservoirs, compaction also causes subsidence at the seabed. Drilling and production platforms can sink dangerously close to the severe-weather line. In the subsurface, significant deformation of downhole tubulars leads to the loss of wells. To alleviate the surface manifestations of subsidence, operators have raised platforms and built

16. Kriging is a geostatistical interpolation technique that accounts for the intrinsic spatial correlation in the property being estimated. Cokriging uses correlated seismic attributes to further constrain kriging, reducing the estimated residual uncertainty.
17. Andersen MA: *Petroleum Research in North Sea Chalk*. Stavanger, Norway: Rogaland Research, 1995.



^ Targeting the highest quality reservoir with specific reservoir-attribute ranges. Reservoir-specific well planning enables hydrocarbon-production and reservoir-drainage optimization in complex fields. In this case, the well path was designed to penetrate high-porosity regions within the reservoir (*left*). It can be highlighted to provide more in-depth analyses of the targeted region (*right*).



^ High-resolution cube analysis. A special filter that enhances lateral discontinuities in the seismic images creates a high-resolution cube. This analysis helps interpreters identify subtle faults (green) and fractures that are less visible on the original seismic section (*left*), which can be integrated with the compaction analysis to reveal further compaction-related features (*right*).

protective concrete barriers. While subsidence can be a serious problem, movement in the strata below can be equally expensive and much more difficult to detect and avoid.

In 1971, early in its productive life, the overpressured reservoirs of the Ekofisk field, operated by Phillips Petroleum, underwent pressure depletion.[18] Because initial porosities were as high as 48% in the Ekofisk formation and 40% in the Tor formation, the anticipated compaction caused by the combination of overburden weight and porosity loss in the reservoir occurred through the early 1990s. In 1987, full-field water injection began, offering a potential means of slowing the rate of subsidence that became evident.[19] The subsidence continued. In 1994, injection rates were increased to stabilize the reservoir pressure, but no reduction in the subsidence rate was observed.

The second reason for the significant compaction is a process called water weakening, which explains the continued subsidence in Ekofisk field.[20] Extensive tests showed that this phenomenon, caused by a chemical interaction between injected water and calcite grains, effectively reduced yield stress and increased the compressibility of chalk formations. These conclusions definitively link the presence of injected water and the tendency for the reservoir to compact after pressure-maintenance efforts. Subsurface monitoring of subsidence proved to be much more difficult than surface monitoring.[21]

In the last several years, time-lapse (4D) seismic imaging techniques have become valuable to asset teams worldwide, enabling them to monitor dynamic reservoir properties.[22] However, to detect and quantify small amounts—less than 2.0 m [6.5 ft] under favorable conditions—of subsidence using seismic methods is a significant undertaking. To this end, scientists at the Schlumberger Stavanger Research Center in Norway have developed a novel approach using 4D seismic techniques to map the subsidence and identify subsidence-related faults.[23] Fault networks delineate reservoir compartments and also impact the flow of injection water. Knowing the location of new and reactivated faults and where the injection water has migrated is crucial to understanding compaction. Asset teams can use this information to help define the flow characteristics of the field and avoid hazards when planning new wells.

Subsidence can be derived by comparison of time-lapse seismic images. Repeatability of seismic acquisition and processing is extremely

18. Sulak RM and Danielsen J: "Reservoir Aspects of Ekofisk Subsidence," *Journal of Petroleum Technology* 41, no. 7 (July 1989): 709–716.

    Ruddy I, Andersen MA, Pattillo PD, Bishlawi M and Foged N: "Rock Compressibility, Compaction, and Subsidence in a High-Porosity Chalk Reservoir: A Case Study of Valhall Field," paper SPE 18278, presented at the 63rd SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, October 2–5, 1988.

19. Johnson JP, Rhett DW and Siemers WT: "Rock Mechanics of the Ekofisk Reservoir in the Evaluation of Subsidence," *Journal of Petroleum Technology* 41, no. 7 (July 1989): 717–722.

20. Sylte JE, Thomas LK, Rhett DW, Bruning DD and Nagel NB: "Water Induced Compaction in the Ekofisk Field," paper SPE 56426, presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, October 3–6, 1999.

    Cook CC, Andersen MA, Halle G, Gislefoss E and Bowen GR: "Simulating the Effects of Water-Induced Compaction in a North Sea Reservoir," paper SPE 37992, presented at the 14th SPE Reservoir Simulation Symposium, Dallas, Texas, USA, June 8–11, 1997.

    Andersen MA: "Enhanced Compaction of Stressed North Sea Chalk During Waterflooding," presented at the Third European Core Analysis Symposium, Paris, France, September 14-16, 1992.

21. Mes MJ: " Ekofisk Reservoir Voidage and Seabed Subsidence," *Journal of Petroleum Technology* 42, no. 11 (November 1990): 1434–1438.

    Menghini ML: "Compaction Monitoring in the Ekofisk Area Chalk Fields," *Journal of Petroleum Technology* 41, no. 7 (July 1989): 735–739.

22. Bouska J, Cooper M, O'Donovan A, Corbett C, Malinverno A, Prange M and Ryan S: "Validating Reservoir Models to Improve Recovery," *Oilfield Review* 11, no. 2 (Summer 1999): 20–35.

23. Schlaf J, Nickel M and Sønneland L: "New Tools for 4D Seismic Analysis in Carbonate Reservoirs," submitted for publication in *Petroleum Geoscience* 9, no. 1 (February 2003).

    Sønneland L, Nickel M and Schlaf J: "From Seismic to Simulation with New 4D Tools," presented at the 63rd EAGE Conference and Technical Exhibition, Amsterdam, The Netherlands, June 11–15, 2001.

    Sønneland L, Nickel M and Schlaf J: "From Seismic to Simulation with New 4D Tools," *Journal of Seismic Exploration* 11 (2002): 181–188.

24. Nickel M and Sønneland L: "Non-Rigid Matching of Migrated Time-Lapse Seismic," *Expanded Abstracts*, 1999 SEG International Exposition and 69th Annual Meeting, Houston, Texas, USA (October 31–November 5, 1999): 872–875.

important for achieving the best possible time-lapse data. Estimates of subsidence and compaction have previously been obtained by using the isochore method, in which the traveltimes of two reference horizons are compared, but this method depends on the quality of the horizon picks. Consistent horizon picking can be a challenging task in itself when reservoirs are structurally or stratigraphically complex.

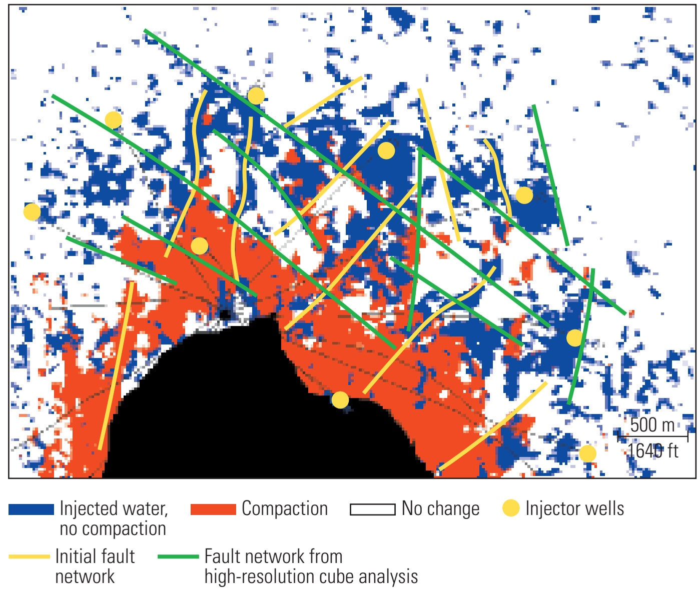
The new method eliminates this dilemma by providing a subsidence and compaction estimate for each sample of a seismic volume, making it a true 3D solution. Following an algorithm developed in 1999, displacement vectors are computed from the time-lapse seismic volumes based on how much displacement would be needed for a sample in the baseline seismic volume to match it to a corresponding sample in the time-lapse volume.[24] The result is a 3D displacement field representing the subsidence distribution for the time between the baseline survey and the time-lapse survey. The derivative of the subsidence distribution is equal to relative compaction.

The analysis also employs a special filter that enhances lateral discontinuities in the seismic images, creating a high-resolution cube. This helps interpreters identify subtle faults and fractures that are crucial for a comprehensive analysis (previous page).

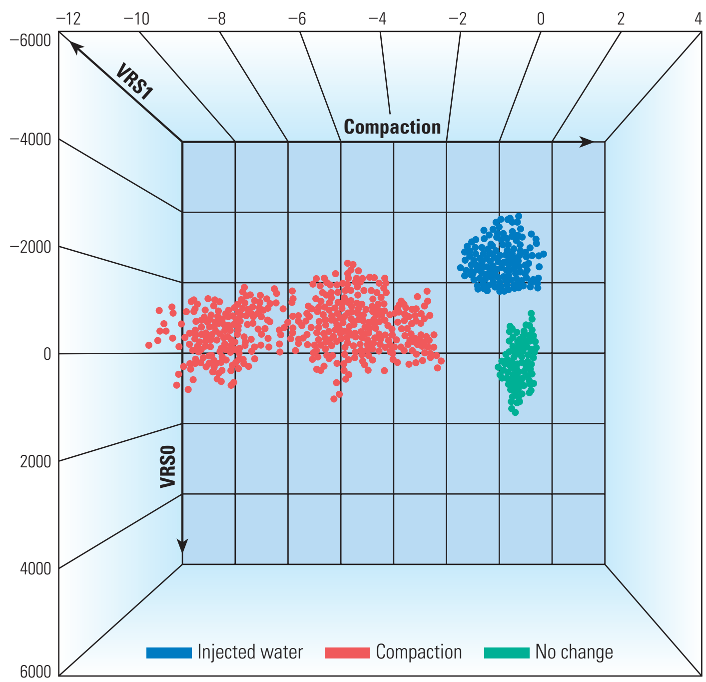
Reservoir dynamics become clear after superimposing compaction data and the detailed fault interpretation on a seismic-attribute map from an inversion process, in this case reflecting fluid content (above right). The map identifies three conditions within the field:

- areas that contain injection water and have experienced compaction
- areas that contain injection water, but have not compacted
- areas that have experienced neither injection nor compaction.

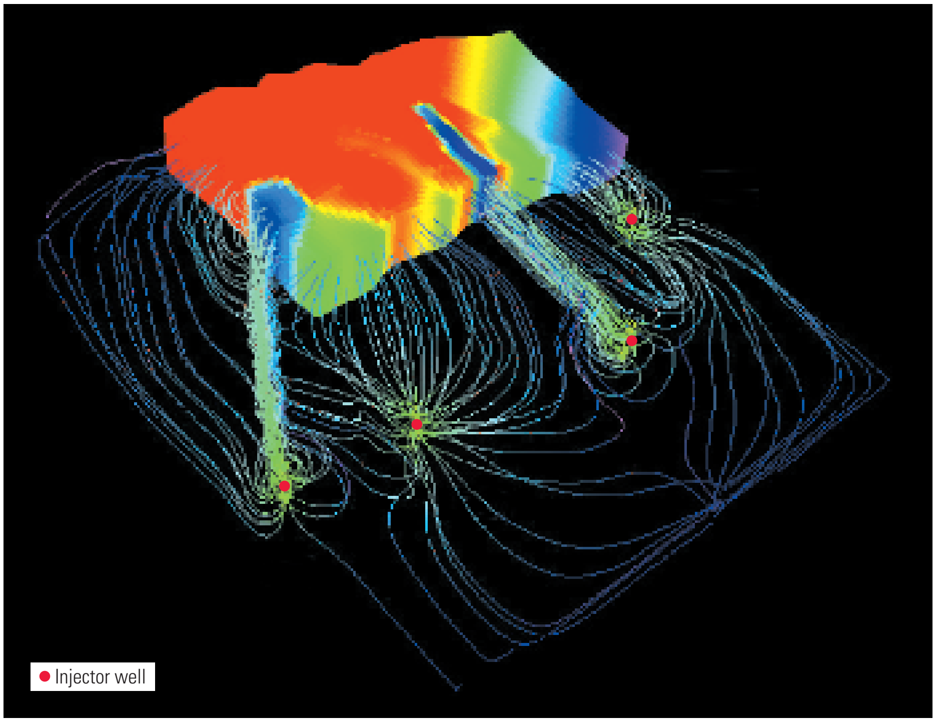
Control points from wells are used to establish the relationship between these three conditions and the seismic-attribute time-lapse changes. The fundamental mapping requirement is that the seismic-attribute time-lapse changes can discriminate between these conditions. This can be verified by plotting the compaction attribute against two other seismic attributes related to the time-lapse changes in the spectrum of reflected energy, volume reflection spectral decomposition (VRS0 and VRS1). Three distinct groupings, or clusters, appear that relate to the three known control conditions (right). The fact that the three groupings are distinct implies that



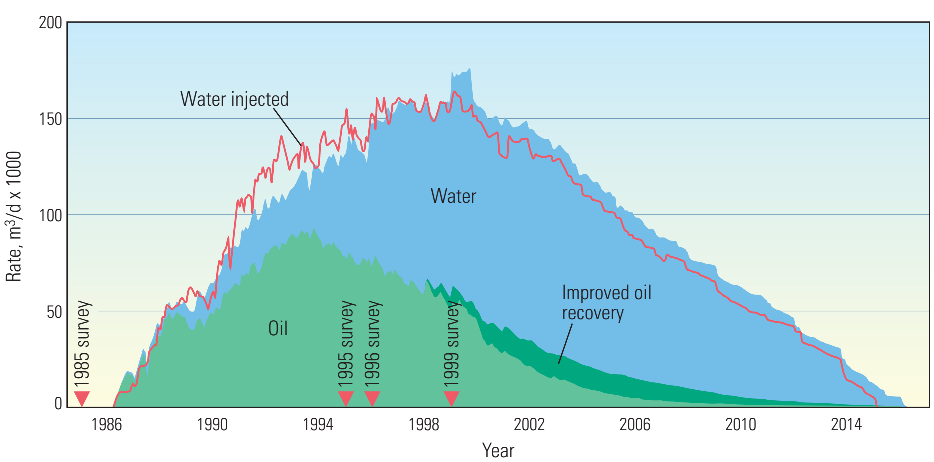
^ Saturation-change map projected onto the top reservoir horizon. Red areas contain injection water and have experienced compaction. Blue areas contain injection water but have not compacted. White areas have not experienced injection or compaction. Previously interpreted faults, the initial fault network (yellow), trend mostly northeast to southwest, and most appear to be conduits for fluid migration within the field. Faults defined from the high-resolution cube analysis (green) trend northwest to southeast and are created from the compaction process or have been reactivated during subsidence. The black area in the southern portion of the map is where seismic data are compromised by gas above the structure.



^ Three distinct groupings relating to the three known control conditions—injected water, compaction and no change. When the compaction attribute is plotted against two other seismic attributes related to the time-lapse changes in the spectrum of reflected energy, the volume reflection spectral decomposition (VRS0 and VRS1), distinct clusters form, implying that the seismic attributes discriminate between the three reservoir conditions. Each condition is assigned a color and mapped accordingly. The blue points identify areas of the field with injected water but no compaction. The red points are regions of injected water with compaction, and the green points are regions of the field that have experienced no change.



^ Using saturation-change data to update flow models in the FrontSim streamline reservoir simulator. Streamlines indicate the fluid-migration path. The density of the streamlines is proportional to flow rates, and saturations are color-coded from high water saturation (blue) to high oil saturation (red). The blackened area is a visualization effect to enable the examination of flow paths. As expected, streamlines start at injector wells and end in zones with high water saturation.



^ Gullfaks field production snapshot. Production in the Gullfaks field began in 1986. The baseline seismic survey was acquired in 1985. After production started to decline in 1994, three time-lapse surveys were conducted, one in 1995 over the northern part of the field and two covering the entire field in 1996 and 1999.

the seismic attributes can discriminate between the three conditions. Ideally, if the repeatability between the time-lapse surveys were exact, then the "no change" cluster would degenerate to the zero point. Hence, the spread of the "no change" cluster indicates the repeatability error. Finally, the situation in which compaction and fluid-content changes have occurred, the compaction condition, shows the greatest scatter, but still falls within a clearly distinct region on the crossplot.

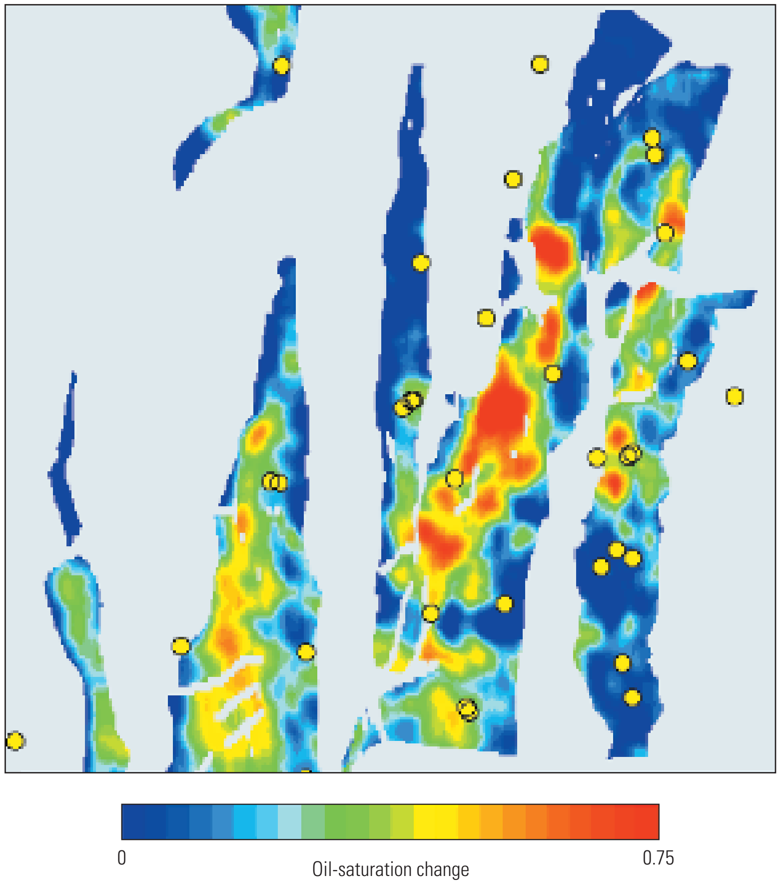
The significance of faulting is clear from this analysis. The faults striking north-south to northeast-southwest have long been identified and appear to be associated with conductive pathways for fluid migration within the field. The faults identified on the high-resolution cube that strike northwest-southeast separate the compacted regions from the noncompacted regions, are interpreted to be reactivated and represent a dire hazard to wells that cross them. Several areas of no change that lie between injector wells and production wells may contain bypassed reserves. This information allows Phillips Petroleum to identify areas where additional production wells should be placed and design the wells to avoid the hazards associated with crossing faults reactivated by compaction.

The 4D analysis helps define the fluid-flow characteristics of the reservoir to improve flow models. To illustrate this, the regions of injected water from the analysis were input into the FrontSim streamline simulator to help identify the connectivity between injector wells and producer wells (above left). This technique uses time-lapse seismic methods to allow asset teams to observe the dynamic processes in and around the reservoir, making the development and production stages more successful by placing wells more effectively.

Quantitative 4D Seismic Analysis

After years of production, mature fields also benefit from continued exploitation of seismic data. Taking time-lapse (4D) seismic "snapshots" at various stages throughout the life of a reservoir allows asset teams to observe dynamic changes in the reservoir resulting from production and enhanced-recovery techniques.[25] This proven technology is applicable in oil and gas fields worldwide, but interpretations have been largely qualitative, describing where reservoir changes take place, but not how much the reservoir has changed. Recent advances allow quantitative-mapping techniques to extend the productive life of fields by uncovering bypassed or unswept

Saturation Change Between 1985 and 1999



^ Estimated saturation change in the upper part of the Tarbert formation in Gullfaks field from 1985 to 1999. Saturation-change data for the upper portion of the reservoir were taken from ECLIPSE reservoir simulations and correlated with the change in reflection strength along the top of the reservoir. Correlations were made in areas where the reservoir-drainage pattern is well-understood and at times corresponding to time-lapse survey acquisition. Red signifies large oil-saturation changes while blue means smaller changes. Yellow circles identify well locations.

reserves. Quantitative mapping techniques are most beneficial when combined with reservoir flow-simulator models.

In the Norwegian sector of the North Sea, Statoil's development of the Gullfaks field is benefiting from a 4D seismic quantitative saturation-mapping project. The Jurassic age Tarbert formation in Gullfaks field is a high-quality sandstone reservoir, with a porosity range of 30 to 35% and permeability up to several darcies. The field is structurally complex, complicating efficient recovery of reserves. Three seismic surveys were acquired and used in the project to resolve the complex fluid distribution within the sandstone reservoir. The baseline survey was acquired in 1985, prior to the start of production in 1986 (previous page, bottom). One time-lapse survey was acquired in 1995 over a portion of the field to the north of the study area and two surveys were acquired over the entire field, one in 1996 and one in 1999.

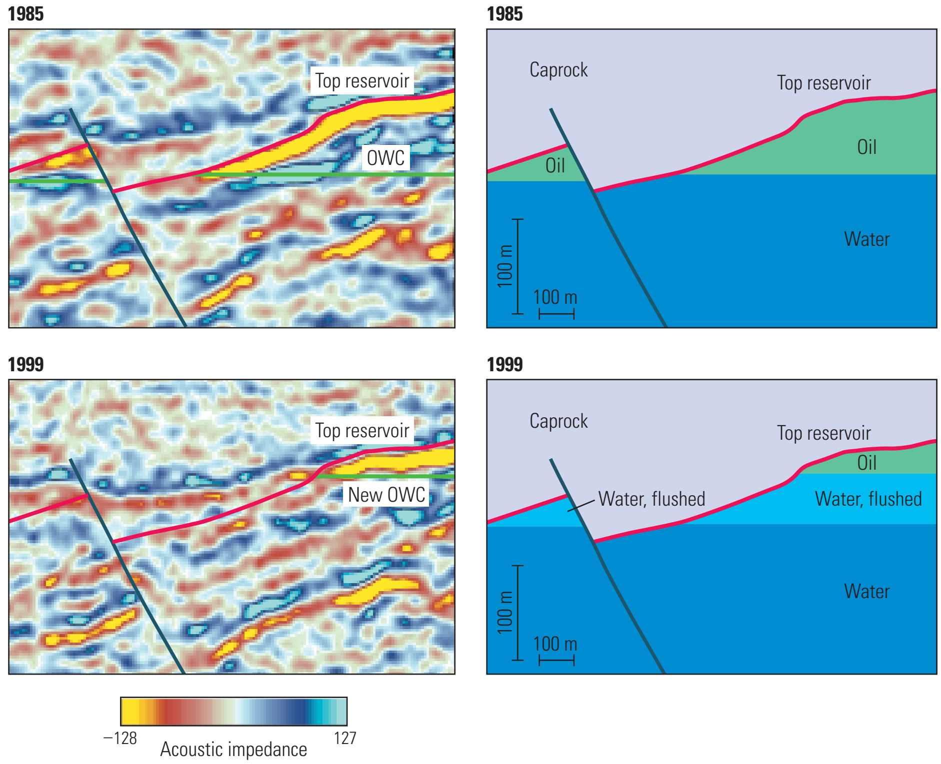
Before the quantitative saturation-mapping project, a detailed model of the Gullfaks reservoirs was constructed and used for fluid-flow simulation. With the use of ECLIPSE reservoir simulation software, a 4D earth model was built to help understand the fluid-movement information within the 4D seismic data. The earth model included both static properties, such as porosity and clay volume, and dynamic properties, such as pore pressure and oil saturation. Dynamic properties were from the flow simulator at the three different seismic-acquisition times in 1985, 1996 and 1999. Elastic-rock properties—including P-wave and S-wave velocities—from a rock-physics model, with input from core and log data, were also used in the 4D earth model.[26] The 4D earth model was required to accurately predict the seismic response and to identify and quantify differences in the seismic response as the reservoir produced through time.

Before these differences could be fully understood, various seismic attributes were calibrated to reservoir conditions, such as saturation. A reservoir simulator was used instead of well logs to correlate change in saturation with the change in seismic attributes in areas of the field where drainage is well-understood, because few of the well log-based oil-saturation values were coincident with the 4D seismic survey acquisition times. Once these relationships were defined, the change in reflection strength was used to generate saturation-change maps (above).

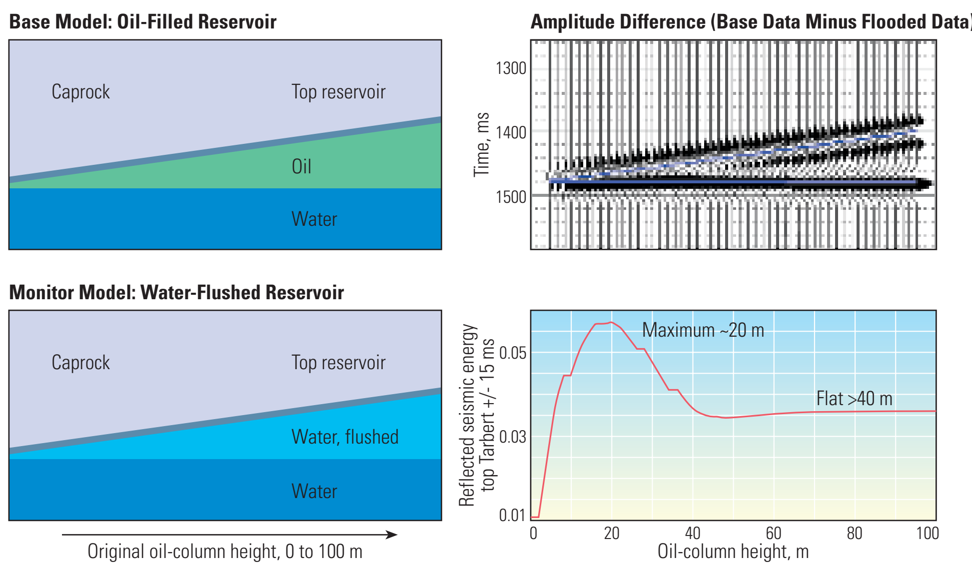
25. Pedersen L, Ryan S, Sayers C, Sønneland L and Veire HH: "Seismic Snapshots for Reservoir Monitoring," *Oilfield Review* 8, no. 4 (Winter 1996): 32–43.

26. Alsos T, Eide AL, Hegstad BK, Najjar N, Astratti D, Doyen P and Psaila D: "From Qualitative to Quantitative 4D Seismic Analysis of the Gullfaks Field," presented at the EAGE 64th Conference and Exhibition, Florence, Italy, May 27–30, 2002.

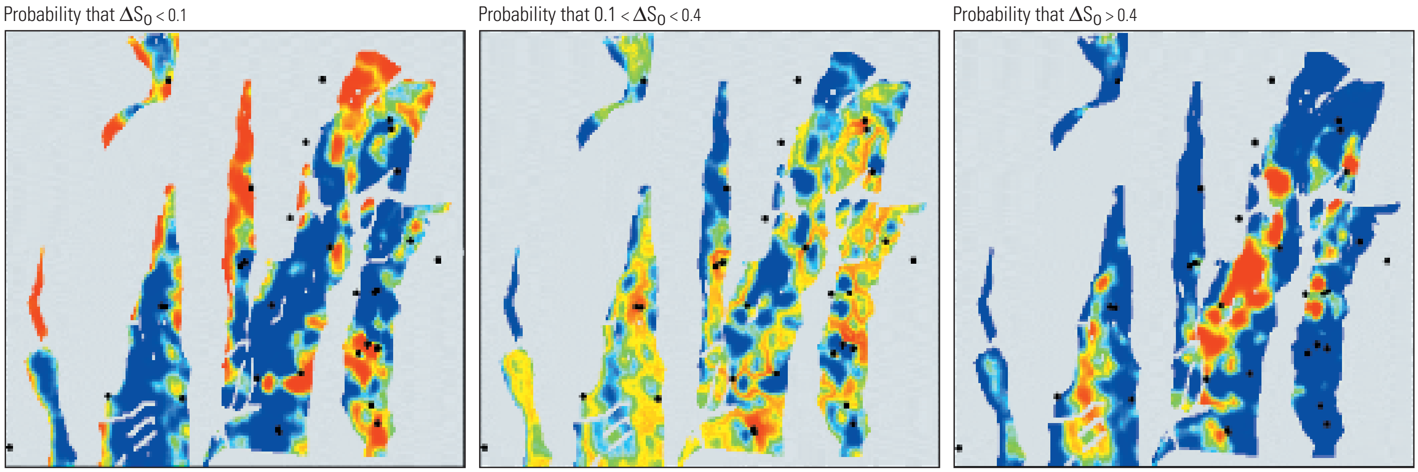
Eide AL, Alsos T, Hegstad BK, Najjar NF, Astratti D, Psaila D and Doyen P: " Quantitative Time-Lapse Seismic Analysis of the Gullfaks Field," presented at the Norwegian Petroleum Society Geophysical Seminar, Kristiansand, Norway, March 11–13, 2002.



^ Reservoir changes observed in 4D seismic images. The 1999 (*bottom*) survey clearly shows the effect of production when compared with the baseline survey of 1985 (*top*). The change in the seismic reflection strength of the top of the Tarbert reservoir is related not only to the saturation change but also to the original oil-column height. When water replaces oil, the acoustic impedance in the reservoir increases, causing a dimming effect on what used to be a strong response from the top of the reservoir. The strong seismic response from the oil-water contact (OWC) in 1985 has also been dimmed due to production. Red and yellow represent a decrease in acoustic impedance, while blue colors represent an increase. Structure, lithology and fluid content are shown in the cross-sectional models on the right.



^ Modeling seismic response to a rotated and flooded fault block. A model of a rotated fault block demonstrated the seismic tuning effect in response to waterflooding (*left*). Flooding a rotated fault block changes the amplitude along the original oil-water contact and along the top reservoir reflector (*top right*). The relationship between reflection strength and the original oil-column height (*bottom right*) shows a maximum at an oil-column height of 20 m [65 ft], and a constant value at heights greater than 40 m [130 ft].



^ Gullfaks probability maps. Probability maps were generated using stochastic simulation because the different classifications overlap. The maps describe the probability of an area being drained, partially drained or undrained according to various oil-saturation changes (ΔS_o). The map reduces the uncertainty in further development because it is quantitative and is a more powerful input to models.

To complicate matters, the change in seismic reflection strength of the top of the Tarbert reservoir is related not only to the saturation change but also to the original oil-column height (previous page, top). This theory was substantiated through synthetic modeling of a rotated fault block, demonstrating the seismic tuning effect in response to waterflooding (previous page, bottom).[27] Adding original oil-column height to the group of variables increases the correlation between seismic attributes and oil-saturation changes. Seismic classification techniques were tested and applied to reservoir-drainage models, enabling the identification of areas in the field as being drained, partially drained or unchanged from the time of the original 1985 survey. Indications of unswept areas within the field form the basis of future well planning and secondary-recovery strategies. However, because the different classifications overlap, there is uncertainty in the identification of the drained and undrained areas. With production wells in the Gullfaks field costing as much as $10 million per well, the Statoil asset team required minimization of this uncertainty. Stochastic simulation using explanatory variables helped to estimate the uncertainty in the saturation change and the probability that a location is drained, partially drained or unchanged (above).

Time-lapse 4D seismic analysis has identified untapped hydrocarbon reserves in mature fields that are fully into the production stage. Advanced drilling and secondary-recovery techniques are used to extract the additional reserves, prolonging field life and increasing asset value. During the last three years in the Gullfaks field, the 4D seismic technique has contributed significantly to the successful drilling of five out of five productive wells. As the remaining infill targets are now small and more risky economically, the quantitative and uncertainty analyses become even more important.

Prospering with Technology

Together with the service providers, E&P companies have a huge stake in advancing seismic technology to develop reserves-replacement opportunities, to identify bypassed reserves in existing fields and to produce their remaining reserves more effectively. The focus is on extracting more detail from the subsurface—both at the reservoir and across the overburden—to support field-related decisions in an appropriate time frame, from right-sizing facilities to optimizing landing points for casing and reservoir entry. Supporting such decisions will continue to place demands on seismic data quality, processing turnaround time, integrated workflows making full use of multiple data types, dynamic 3D visualization, and people in various disciplines. New seismic technologies will continue to find new prospects in challenging environments, and innovative processing techniques will unlock prospects already acquired but deemed high risk due to lack of clarity. The technology and the people behind it are making a difference. Successful seismic reservoir applications are numerous and continue to grow. Consequently, the life of a reservoir has never been more productive. —MG

27. Tuning is the phenomenon of constructive or destructive interference of waves from closely spaced events or reflections. In this case, at a spacing of less than one-quarter of the wavelength, reflections undergo destructive interference and produce a single event of low amplitude. At spacing greater than one-quarter wavelength, amplitudes fall and the event begins to be resolvable as two separate events. The tuning thickness is the bed thickness at which two events become indistinguishable in time, and knowing this thickness is important to seismic interpreters who study thin reservoirs.