Through the continuous life cycle of reservoir, geophysics makes its mark

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A quiet revolution has been taking place in the geophysical community. Assisted by better measurements and faster processing, seismic data have become an essential tool for reservoir management. Using seismic to monitor the behavior of reservoirs in production is not a new concept, but it has taken some time to evolve from a theoretical principle to a practical necessity. By developing the ability to perform highly accurate time-lapse seismic surveys, production geophysicists have been able to observe and quantify changes in the seismic data that can only be the result of fluid movement within the reservoir. This provides a heretofore unavailable macro-image of the reservoir's behavior over time that can be used to calibrate sophisticated numerical simulators, long used by reservoir engineers to predict performance.

Even mature reservoirs, already having a vast cache of information from exploration seismic, well log, drilling, and production data taken from numerous wells, benefit from seismic production monitoring. The reason is that no amount of data projected from a limited number of reservoir penetrations can accurately predict production performance. Heterogeneities exist between the wells. It may be possible to identify permeability anisotropy in a wellbore, but it cannot be projected confidently more than a few meters into the formation. Overall, production can be measured, but the effect of any single lithological or structural event can only be inferred. As has been proven time and again, the pathway to reservoir characterization can be found only by unlocking the secrets that lie between the wells.

Reservoir simulators have been used for several years to fill in gaps in the data, and to make stochastic predictions using history-matching techniques. Early attempts to derive useful information from simulators were limited by the fact that if one built a simulator with a sufficient number of cells to yield a definitive result, processing time was excessive. Only recently has this problem been resolved through the use of more powerful high-speed processors coupled with the ability to achieve project compartmentalization. Today, reasonable results from reservoir simulators can be obtained in near-real time.

The traditional role of seismic technology tended to mimic the conventional view of the life cycle of a field; a linear process starting with exploration and ending with abandonment. Conventional seismic technology has delivered subsurface images, and buying decisions have been dictated by immediate imaging needs within the cycle, but without consideration for future imaging requirements. In addition, conventional seismic data are rarely of sufficient resolution or fidelity to reliably extrapolate quantitative maps of reservoir properties such as porosity.

Today's dynamic exploration and production environment demands much more, and advanced seismic technology plays a key role. With brownfield exploration, step-out exploration, and exploration near existing facilities, the life cycle of a reservoir becomes a continuous loop. Seismic data buying decisions must take this into account. WesternGeco describes this cycle as the "geophysical continuum," defined as the connected life cycle of an oilfield where uncertainty is reduced by using high-fidelity seismic measurements that are consistently calibrated with all other oilfield measurements (Figure 1).

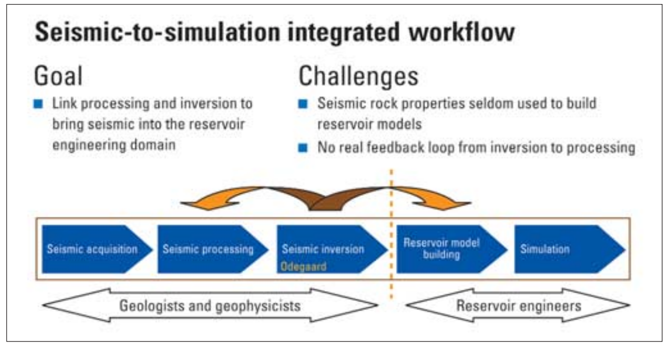

***Figure 1.** The geophysical continuum is illustrated in this seismic-to-simulation integrated workflow. (Image courtesy of Schlumberger).*

A major factor enabling fast turnaround has been the use of Q-Technology systems. WesternGeco developed this technology to deliver advanced seismic measurements that can span the life of a reservoir, from providing the best exploration images to delivering quantitative rock and fluid properties for development and production. The key to unlocking this potential lies in making fundamentally better seismic measurements that deliver greater reservoir detail, allowing seamless calibration with other geophysical and borehole data. The geophysical continuum reduces uncertainty between wells and provides operators with a greater degree of confidence. The final link in the chain was forged with the recent acquisition of Odegaard, whose technology finally bridged the gap between geophysicists and reservoir engineers. Also instrumental in facilitating communication between geoscientists and engineers has been the introduction and development of high-resolution 3D dynamic visualization—seeing is believing.

Enhancing the reservoir model. Technical innovation in acquisition and processing has been accompanied by a paradigm shift to achieve complete integration of seismic with other well and reservoir technology. The integration of seismic and other well data is synergistic; that is, data sets are mutually supportive, and additional information can be derived from their combination. An example using a high-resolution Q-Land data set from Kuwait Oil Company demonstrates this point. Seismic data inversion was combined with rock physics analysis and multi-attribute analysis using a neural network to optimize a new water flood project in the Magwa Field. A hexagonal pattern of six oil producers was driven by a single water injector located in the center. When water flooding commenced, five wells produced oil, one well produced only water for two months, and then its water cut reduced to about 70%. Pressure tests showed nonuniform interwell communication. A project was undertaken to transform seismic reflectivity into reser-

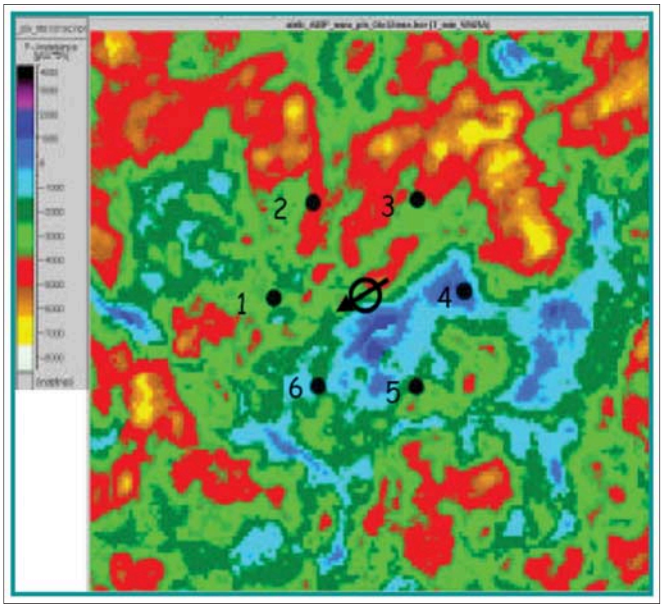

Figure 2. The value of integration can be seen in this acoustic impedance attribute map made from high-resolution single sensor seismic data taken over this hexagonal pattern of oil producers driven by a central injector well. Interwell gaps are populated with meaningful information that enabled production optimization.

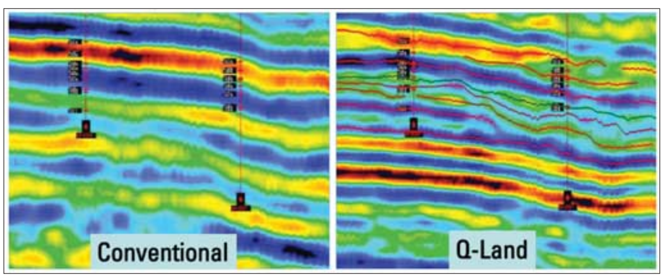

Figure 3. Well-to-well correlation completely missed the interwell permeability barrier that hampered flow of injection water (left). Q-Technology correctly imaged the zone (right).

voir properties so reservoir drainage patterns could be better understood. By plotting acoustic impedance (AI) versus reservoir properties such as effective porosity, lithology, and water saturation, detailed maps were constructed that enabled optimization of the waterflood project. A multi-attribute neural network technique was used to predict reservoir properties from the AI. This enabled synthesis of the inter-well variations in reservoir properties that were affecting the flood and drainage patterns (Figure 2).

Another example from Kuwait shows how interwell factors completely compromised a water flood scheme. Conventional methods indicated that injection fluid should flow freely from the injector well to the prospective producer. When this didn't happen, further investigation using Q-Land illuminated all seven reservoir zones, revealing several pinchouts as well as a tar mat barrier between the wells. By understanding the actual downhole situation, the operator was able to modify the production scenario, predicting water movement and identifying unswept oil to add reserves and enhance oil production (Figure 3).

In Mexico's Arenque and Lobina carbonate reservoirs offshore in the Gulf of Mexico, high-resolution Q-Marine seismic was used to improve knowledge of key reservoir properties leading to better field development decisions. Several new drilling locations and in-fill opportunities were optimally sited and prioritized following the study. Using log and core data, AI measurements from the complex conglomerate were translated into porosity-height (Phi-h), a running summation of the seismic trace covering the gross reservoir intervals. Mapping the maximum porosity between the reservoir boundaries helped identify "sweet spots" that were subsequently targeted for development wells. In addition to identifying several in-fill locations for the mature Arenque Field and prioritizing development opportunities in the relatively new Lobina Field, a potential new field was identified on the northeast quadrant of the structure (Figure 4).

Norne through the years. To see how the seismic-to-simulation concept works in practice, the results of a recent 4D

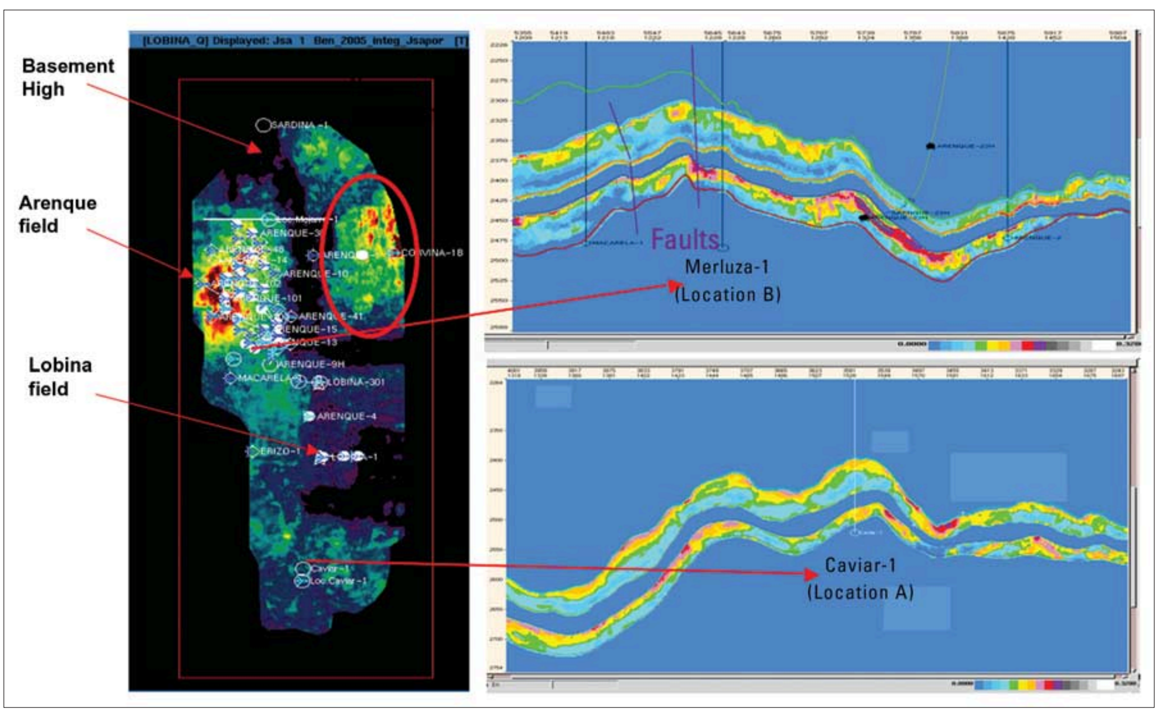

Figure 4. Porosity-height calculations derived from area-wide acoustic impedance calibrations helped PEMEX choose between the high-potential Merluza-1 site and the Caviar-1. A good choice, Merluza-1 came in at 2000 bo/d, added 6MMbbl of oil and 8.7 Bcf of gas reserves and ranked second among all PEMEX wells drilled in 2005.

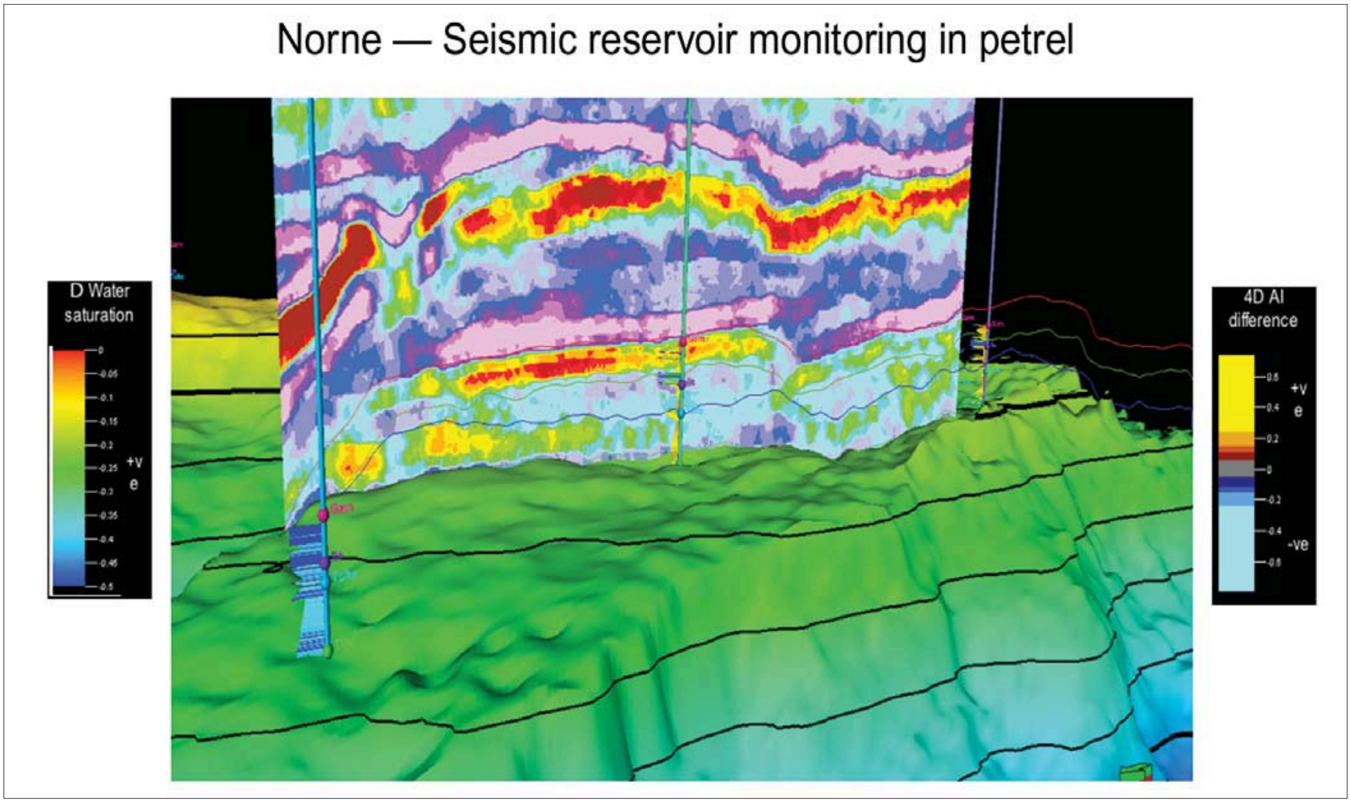

Figure 5. *Time-lapse (4D) monitoring helps identify changes in water saturation indicated by increases in acoustic impedance that signify encroaching water levels or injection water breakthroughs.*

seismic survey over the Norne Field helped operator Statoil monitor fluid movements, improve planning of in-fill drilling, improve the field recovery factor from 40% to 52% and extend field life beyond 2015. Q-Marine 4D seismic monitoring commenced at Norne with a baseline survey performed in 2001. Subsequent surveys acquired in 2003, 2004, and 2006 have provided excellent insight into reservoir drainage patterns. Taking several key areas of the reservoir, Statoil engineers were able to develop production scenarios that were supported by the data. For example, a seismic slice using baseline survey data shows AI relative to water-saturation curves from the well logs. Then, by looking at the difference between the 2003 data and the baseline survey, a 4D feature is seen just above the original oil-water contact. A three-dimensional mapped image of this feature can be rotated to observe its relationship to known structural boundaries such as sealing faults, and thus can be attributed to the influx of water displacing the oil. This technique was applied in other areas of the field with similar results, namely, that an observed increase in AI could be confidently interpreted as having been caused by water replacing oil as the reservoir fluid (Figure 5).

Predicting drainage patterns that conform to a previously developed model is not very exciting, but can certainly validate the technique. The real value comes when the 4D results show changes not predicted by the model. This happened several times at Norne. In the Garn Formation, the uppermost reservoir, water encroachment was predicted from the model as migrating to the northwest and south of the well. But 4D inversion clearly showed water migrating to the east. This indicated that there were flow paths present that were not recognized by the model, affecting subsequent field development plans.

How this is done can be illustrated by examining the seismic section with formation tops and projected development well plan superimposed (Figure 6). Original development plans called for a well to drain the Ile reservoir as shown by the black well trajectory. A carbonate-cemented barrier had been interpreted to lie between the Tilje and Ile formations, and pressure data from several offset wells indicated this to be a sealing barrier. The AI differences between the baseline survey and the 2003 survey can be seen (reds indicate an increase in AI between baseline and 2003 and blues indicate a decrease in AI over the same period). It is obvious that water has penetrated the supposedly sealing carbonate barrier and is encroaching on the base of the Ile formation. When the 3D geobody was "grown"to map the volume represented by the 4D effect caused by water replacing the oil, it was clear that the proposed well path was very close to the new oil-water contact; in fact, the toe of the proposed well was right in the middle of a water zone. The 4D fast-track results were processed onboard the survey vessel and delivered for interpretation within a week of acquisi-

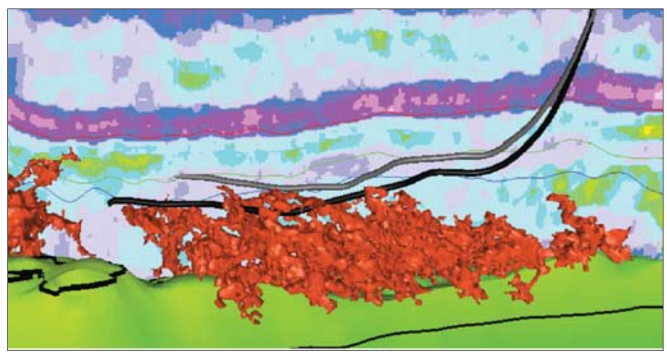

Figure 6. *Differences in AI signaled localized water encroachment through a leaking barrier and caused the operator to redesign the proposed horizontal well. The original well plan (black) was too close to the water. The revised well plan (gray) will add to the reservoir's productive life.*

tion. As a result of this interpretation, over the following seven days Statoil revised the well track, placing it in the same reservoir but above the indicated new water level (shown by the gray well trajectory). The well was drilled on the new trajectory and flowed 25 157 b/d (4000 Sm^3/d) of oil with no water on start up. It was believed that the water encroachment through the carbonate barrier was caused by several small subseismic faults that penetrated it. This theory was borne out by inserting several small-scale faults into the simulation model to see what the result would be. When this was done, the 4D data matched the model.

Time and again 4D results have been used to verify the accuracy of the reservoir model, or conversely, to dispute it. Norne's complex geology is a perfect candidate for time-lapse seismic, and confidence in Statoil's ability to make correct predictions has grown as production tests confirm decisions made as a result of using the seismic-to-simulation approach.

Two additional cases at Norne involved issues where well data were ambiguous, and modeling was unable to resolve production problems or predict with confidence. In both cases, 4D provided the missing link. According to Statoil, the contribution of accurate 4D data to drill in-fill wells at Norne has been estimated at US$240 million. High quality seismic data along with tight and seamless integration with petrophysical and reservoir engineering well data were essential elements in achieving the results experienced to date.

Facing the future. With deepwater wells costing $25 million or more to drill, operators face three main challenges—reducing exploration risk, reducing upfront costs, and protecting their investment. They can accomplish these objectives by using complementary technology to narrow the search and improve the likelihood they will discover a hydrocarbon-bearing structure before spudding the first well. New planning and design software helps operators assess the potential risks and rewards of each technology application before investing. Economical broad-brush bathymetry/gravimetry surveys and magnetotellurics can identify basin geometries and indicate the thicknesses of resistive strata respectively. Q-Marine provides 3D seismic imaging that can define images beneath salt layers. Finally, once a promising structure has been imaged, controlled source electromagnetic surveys may define the areal extent of hydrocarbon reservoirs within it. The enhanced knowledge provided by these technologies and techniques when integrated into the 3D whole earth model can effectively reduce exploration and drilling risk.

The geophysical continuum—A practical reality. The recent integration of WesternGeco with Schlumberger has made the geophysical continuum complete. Whether the driving force is adding or replacing reserves, increasing production, maximizing recovery, unlocking unconventional hydrocarbon potential, or some combination of these, the links are strengthened. By treating reservoir management as a continuous lifecycle, operators benefit from the synergies that derive from a fully-integrated service company. What engineers like to call "from pore to process" is mimicked by the "seismic to simulator" approach. Together they form a powerful bond that can deliver valuable knowledge for the life of the reservoir. TLE

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