Time Will Tell: New Insights from Time-Lapse Seismic Data

Advanced time-lapse seismic acquisition technology improves repeatability by greatly reducing two problems of conventional seismic surveys—noise and positioning—that obscure images of genuine physical changes in a reservoir. Calibrated, repeatable seismic measurements reveal actual changes in a reservoir and help oil and gas companies identify fluid types, map fluid saturations and make more informed decisions during drilling, development and production. This improved reservoir management helps companies maximize oil and gas recovery.

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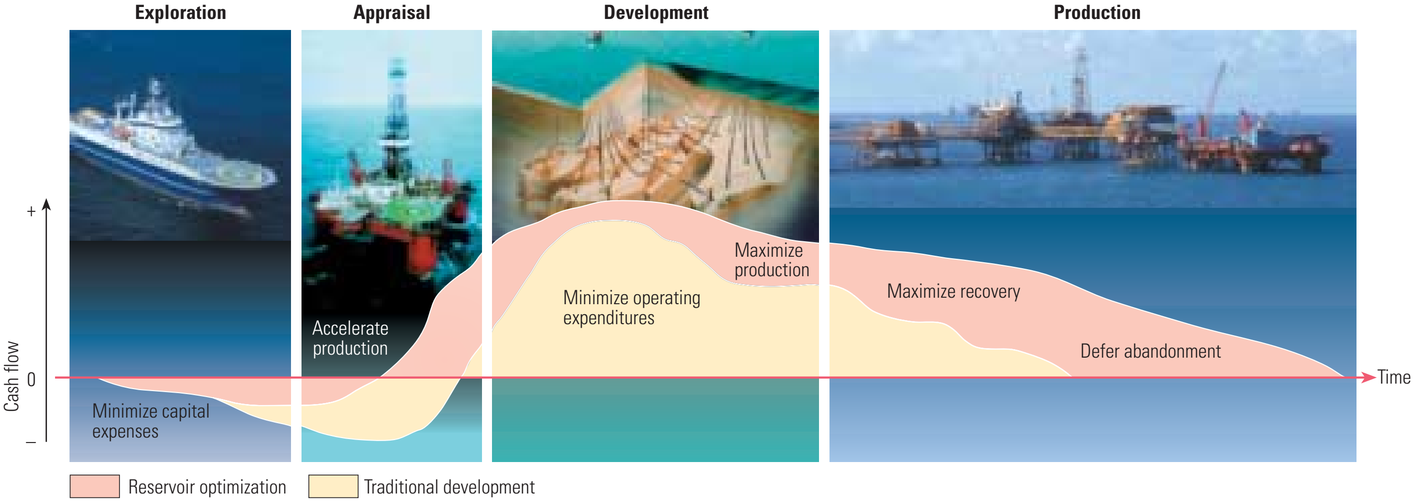

^ Time-lapse data applications. During field appraisal, acquisition of a baseline 3D seismic survey helps the operator accurately map the field and plan development drilling. Early in the production cycle, particularly in fields that have gas coming out of solution, the decreasing pressure produces an obvious seismic response. Time-lapse seismic surveys early in the production cycle offer vital information about future performance. As the field reaches maximum production, a time-lapse survey helps detect bypassed hydrocarbons and guides development well-location selection. As production declines, additional surveys help the operator manage injection operations to maximize recovery from mature fields.

Understanding how a reservoir behaves over time requires observations and measurements at various times. Reservoir engineers and well-logging specialists are familiar with certain time-lapse measurements, such as flow rates, pressure tests and saturation monitoring of individual wells. Less familiar, perhaps, but gaining widespread application, are time-lapse surveys that reveal seismic changes as large regions of the reservoir react to the production process.

A time-lapse seismic survey compares two or more seismic surveys acquired at different stages of hydrocarbon production. Although many time-lapse studies involve three-dimensional (3D) seismic data, some studies compare seismic lines (2D seismic data) and wellbore seismic data (1D seismic data). Known variously as time-lapse, four-dimensional (4D, the fourth dimension being time), or repeat 3D surveys when 3D data are used, these seismic surveys help exploration and production (E&P) companies understand reservoir architecture and map the movement of fluids in reservoirs over time.[1] It is also possible to gain some understanding of changes in the reservoir rock itself, such as compaction effects, from time-lapse data.[2]

Obtaining time-lapse seismic data is important to the entire asset team—engineers, geologists, geophysicists and petrophysicists—who avail themselves of these data to identify, map, understand and monitor reservoirs.[3] High-quality time-lapse data are more than just a means to monitor reservoirs—time-lapse surveys now play a vital role in reservoir management.[4]

Comparing surveys might reveal changes in seismic attributes that are indicative of a reservoir's fluid content, but only if the seismic measurements are precise and the positions of the seismic sources and receivers are accurate.[5] To properly evaluate subtle changes in reservoirs, a repeat seismic survey must closely match the characteristics of the previous survey.[6] It is relatively easy to run a repeat survey by using the same types of seismic sources and receivers, and by acquiring data in the same survey direction and at the same line spacing as in the baseline survey. However, these efforts do not assure complete replication. Certain aspects of seismic surveys are beyond human control, such as topography, tides, currents, water tables, weather and surface obstacles, and these can overwhelm efforts to replicate a baseline survey. Seasonal variations, such as freeze-thaw cycles and precipitation, commonly dictate the timing of seismic surveying.

Advanced acquisition technology plays a critical role in improving survey repeatability. In fact, survey repeatability is now high enough to detect changes in some reservoirs in a matter of months. In addition, more powerful computers and improved workflows bring time-lapse seismic data to the asset team in a meaningful time frame. When the first time-lapse surveys were acquired in the 1980s, the time required to process the data was measured in months, similar to the amount of time required for discernable fluid movement to occur. Part of the difficulty was dealing with the immense quantity of data. A more time-consuming task was to manipulate and match surveys that had poor repeatability. Now, large surveys can be acquired and processed rapidly, with seismic interpretation beginning during or shortly after acquisition.

Like all technologies applied in the oil field, the benefits of time-lapse seismic data must outweigh the costs by detecting additional reserves, reducing development or production costs, or reducing risk (above). Presurvey geophysical

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1. For more on the basics of time-lapse seismic data and their use in reservoir monitoring: Pedersen L, Ryan S, Sayers C, Sonneland L and Veire HH: "Seismic Snapshots for Reservoir Monitoring," *Oilfield Review* 8, no. 4 (Winter 1996): 32–43.
2. For more on the use of time-lapse seismic data to evaluate reservoir compaction: Nickel M, Schlaf J and Sønneland L: "New Tools for 4D Seismic Analysis in Compacting Reservoirs," *Petroleum Geoscience* 9, no. 1 (February 2003): 53–59.

   Alsos T, Eide A, Astratti D, Pickering S, Benabentos M, Dutta N, Mallick S, Schultz G, den Boer L, Livingstone M, Nickel M, Sønneland L, Schlaf J, Schoepfer P, Sigismondi M, Soldo JC and Strønen LK: "Seismic Applications Throughout the Life of the Reservoir," *Oilfield Review* 14, no. 2 (Summer 2002): 48–65.
3. Walker R: "A New Level of Confidence for the Asset Manager," *Proceedings of the 17th World Petroleum Congress*, Rio de Janeiro, Brazil, September 1–5, 2002.
4. Shirley K: "Seismic Targets: Sweep the Pools," *AAPG Explorer* 25, no. 3 (March 2004): 14.
5. Differences revealed by time-lapse surveys are often assumed to denote changes in reservoir fluids. However, this assumption is not always correct. There are cases in which time-lapse surveys record changes in rock properties, such as in reservoirs that undergo compaction during production.
6. E&P companies have used legacy surveys acquired for different purposes to evaluate time-lapse effects. The purpose of a seismic survey may affect how it is acquired, so the legacy surveys might have significantly different acquisition parameters. For an example of time-lapse monitoring using legacy surveys: Kovacic L and Poggiagliomi E: "Integrated Time-Lapse Reservoir Monitoring and Characterization of the Cervia Field: A Case Study," *Petroleum Geoscience* 9, no. 1 (February 2003): 43–52.

modeling helps determine whether a given survey is likely to generate usable data. Time-lapse surveys often represent a small fraction of the cost of a new well, particularly in expensive operating arenas such as the deep water, where well construction might cost tens of millions of dollars.

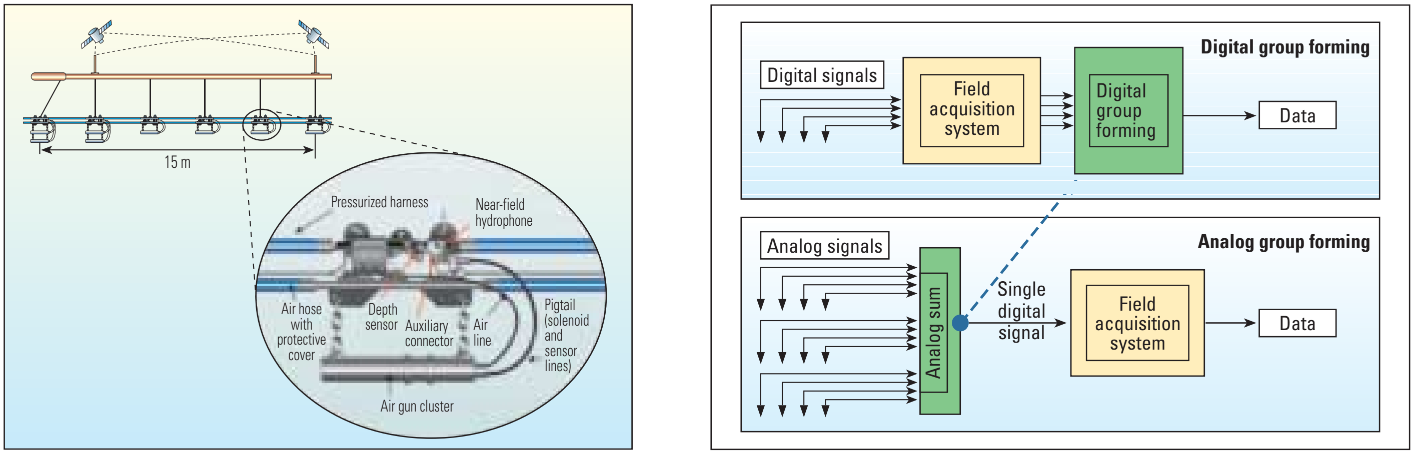
In this article, an example from the Norwegian Sea demonstrates the impressive insights now accessible through time-lapse seismic data and the way these insights guide ongoing operations. We also describe a robust approach to reservoir simulation that combines production and time-lapse seismic data to generate a quantitative time-lapse analysis. To begin, however, we review recent advances in seismic acquisition technology.

New Acquisition Technology

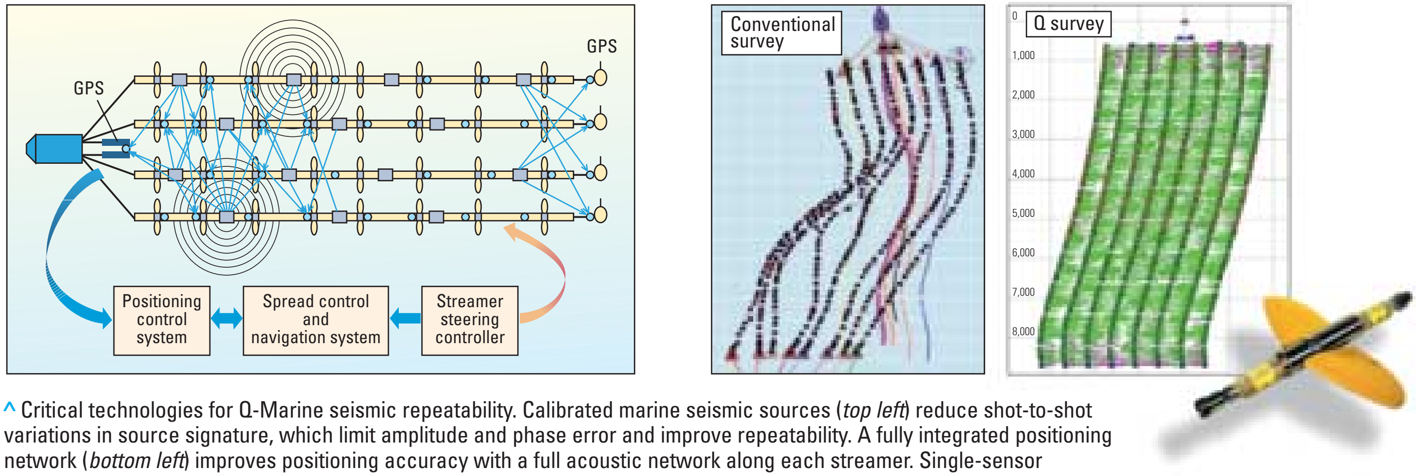
Seismic survey repeatability is a prerequisite for meaningful time-lapse interpretations. Improved positioning and reduced noise are keys to survey repeatability.[7] On land, it is easy to imagine repeating a seismic survey by installing sensors and using the same seismic sources for subsequent surveys, but the reality is not so simple. Repeatability depends on the geophones being planted, or placed in the ground, in the same way and remaining firmly in place until the next survey. Landscapes can change, potentially moving geophones between surveys, such as in areas where sand dunes migrate or erosion occurs. Seasonal climate variations also affect seismic acquisition. For example, in tundra that freezes and thaws regularly, time-lapse seismic surveying should occur during the same season as the previous survey. Activities of people and animals might also interfere with sensor positioning.

It is possible to permanently install sensors on the seafloor, as was first done by WesternGeco and BP in the Foinaven field in 1995, but this technology is costly.[8] Repeatability is imperfect if the area experiences movement of seafloor sediments, changes in seawater salinity and water-layer temperatures, or production-induced geomechanical effects. Permanent seismic sensors were installed recently at Valhall field, operated by BP offshore Norway, so that data-gathering can occur at any time.[9] In addition to repeatability improvements for time-lapse seismic acquisition, the Valhall sensors acquire multicomponent data, which are essential to imaging beneath a gas cloud (see "The Many Facets of Multicomponent Seismic Data," *page 42*).

Calibrated Marine Source **Single-Sensor Recording**



Fully Integrated Positioning Network **Streamer Steering**



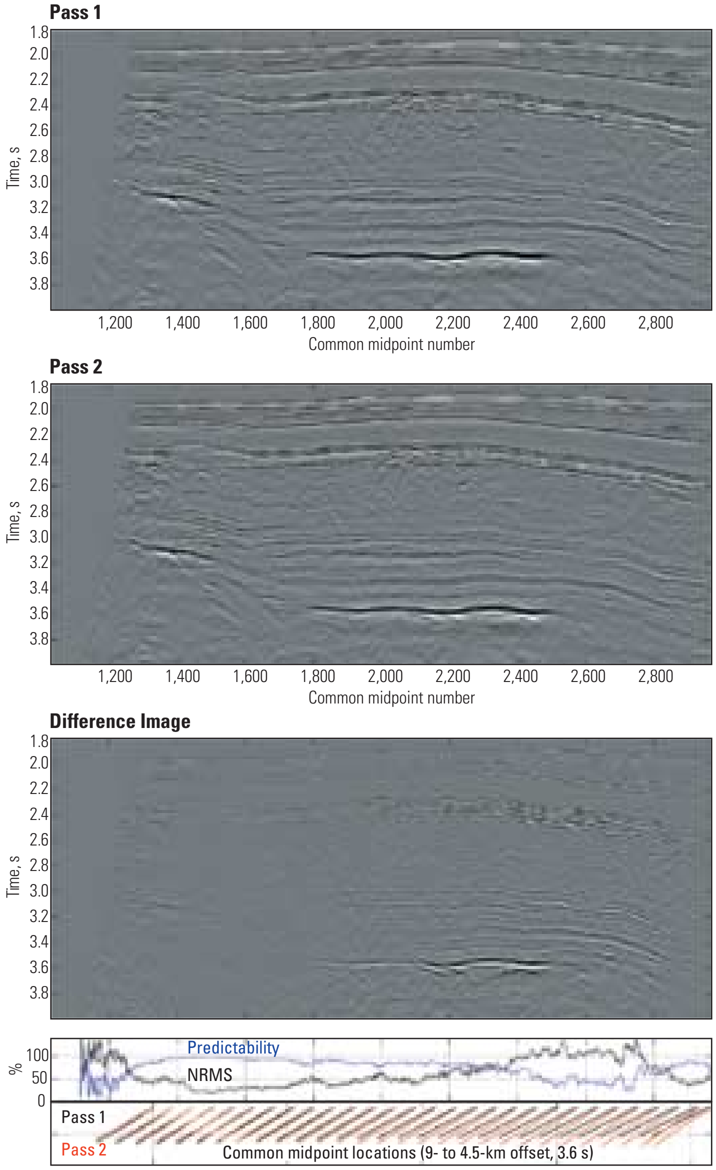
^ Critical technologies for Q-Marine seismic repeatability. Calibrated marine seismic sources (*top left*) reduce shot-to-shot variations in source signature, which limit amplitude and phase error and improve repeatability. A fully integrated positioning network (*bottom left*) improves positioning accuracy with a full acoustic network along each streamer. Single-sensor recording (*top right*) with calibrated hydrophones facilitates use of advanced noise-reduction algorithms. Streamer steering (*bottom right*) helps reliably replicate the geometry of previous surveys. Towed-streamer surveys that lack active streamer control run the risk of streamer feathering and tangling, as shown in the conventional survey at left. Greater control of streamer positioning, as seen in the Q survey to the right, requires a fully integrated positioning network. The photograph at bottom right shows a fin with remotely controlled "wings" that control depth, horizontal position and streamer separation.

Towed-streamer seismic data offer an economical alternative to permanent sensors in marine environments. However, the streamers and sources towed by the seismic vessel must retrace the paths of their predecessors, regardless of wind, waves, currents and other variables. The streamers are up to 8 km [5 miles] long, and there are usually eight of them. Currents can force streamers to feather, or deviate, from their programmed locations, sometimes to the extent that the streamers tangle. Waves and rough weather also make it difficult to deploy streamers and seismic sources at the depths required by the survey design. The noise levels observed in surveys acquired under different conditions could be erroneously interpreted as changes in reservoir properties. Engineers and scientists from WesternGeco and Schlumberger recognized that significant technical improvements were necessary to achieve the repeatability required for reservoir management.

The newest WesternGeco seismic acquisition system controls the major acquisition factors that affect repeatability—background noise and positioning of sources and receivers—better than conventional systems.[10] Four significant technical advances set time-lapse surveys acquired using the Q-Marine single-sensor marine seismic system apart from conventional time-lapse surveys: streamer steering, a fully-integrated positioning network, calibrated marine sources and single-sensor recording (previous page).

In an ordinary marine repeat survey, it is difficult to consistently acquire data in the same positions, especially in waters with strong currents. Q-Marine technology incorporates the Q-Fin marine seismic streamer steering system, with fins typically placed at 400-m [1,300-ft] intervals along each streamer. This Q-Fin technology dramatically improves repeatability by adjusting the streamer position using two remotely controlled "wings" to control depth and horizontal position (right).

The Q single-sensor seismic acquisition and processing methodology includes a fully integrated positioning network with a positioning-control system that interfaces with the spread control and navigation system. This positioning-control system accurately measures the position of the streamers throughout their length and, with the fins, allows a repeat survey to replicate the geometry of the previous survey within the limits of the steering capability. It also enhances the safety of surveying operations by minimizing the risks of streamer tangling and



^ The role of positioning in time-lapse survey repeatability. The conventional seismic sections at the top and in the middle are experimental passes acquired using ordinary acquisition technology in the Gulf of Mexico. The difference section at the bottom shows the difference between Passes 1 and 2, with the largest differences on the right side of the section. The plots beneath the difference section show the predictability, normalized root-mean-square (NRMS) and source-receiver midpoint locations in each pass, with greater variation to the right. The lack of exact positioning, rather than actual changes in the reservoir, produced the differences, underscoring the need for precise positioning during repeat surveys. The plot of predictability and NRMS also shows that high predictability and low NRMS indicate higher repeatability, with better results on the left side of the plot.

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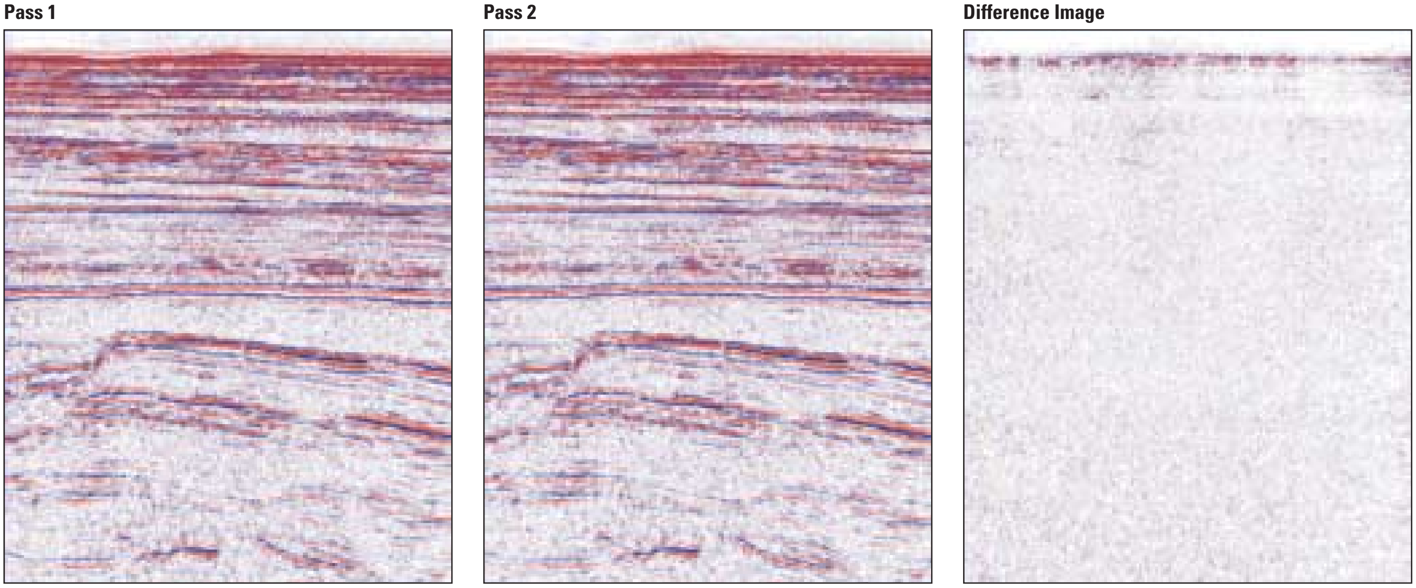
7. Noise refers to disturbances in seismic data caused by any unwanted seismic energy, such as shot-generated ground roll, surface waves, multiples, effects of weather and human activity, or random occurrences in the Earth. Noise can be minimized in conventional seismic surveys by using source and receiver arrays, generating minimal noise during acquisition and by filtering and stacking data during processing.
8. Kristiansen P, Christie P, Bouska J, O'Donovan A, Westwater P and Thorogood E: "Foinaven 4D: Processing and Analysis of Two Designer 4Ds," presented at the 70th Annual Meeting of the Society of Exploration Geophysicists, Calgary, Alberta, Canada, August 6–11, 2000.
9. Durham LS: "Repeatability Is Key for 4-D Data," *AAPG Explorer* 25, no. 3 (March 2004): 12–13.
10. Strudley A and Smith P: "Offshore 4-D Acquisition Improves," *Hart's E&P* 75, no. 3 (March 2002): 49–50.

    For more on the Q system and comparisons of conventional and Q-Marine data: Christie P, Nichols D, Özbek A, Curtis T, Larsen L, Strudley A, Davis R and Svendsen M: "Raising the Standards of Seismic Data Quality," *Oilfield Review* 13, no. 2 (Summer 2001): 16–31.



^ The role of Q positioning technology in time-lapse survey repeatability. The Heidrun baseline swath (*left*) and repeat swath (*center*) were acquired using steerable streamers and underwent the same deterministic processing sequence. The difference section at right shows a relatively low NRMS of 15%. In this case, there is no time-lapse signal because of a short time interval between the surveys, during which there was little or no production. However, because of the high level of acquisition repeatability, there is also minimal noise, so rock and fluid changes over a period of hydrocarbon production could be interpreted with significantly more confidence on a Q time-lapse survey than on a conventional time-lapse survey.

streamer collision with obstructions such as oil- and gas-production platforms.

Variability in source output and in the sensitivity of receiver arrays perturbs seismic measurements and appears as noise in time-lapse surveys. A time-lapse signal is detectable and reliable only if it is not masked by this noise. Therefore, Q-Marine source and receiver systems are precisely calibrated to optimize the sensitivity to relatively weak time-lapse signals. In particular, calibrated Q-Marine air-gun sources compensate for shot variations stemming from timing errors, interaction between shots and pressure variations between shots.

Digital recording of each individual hydrophone facilitates powerful filtering to remove noise caused by vibrations and the application of deterministic corrections to remove small variations in the sensitivity of all sensors.

The four major technical advantages of the Q system were put to the test in a time-lapse acquisition experiment offshore Norway in the Heidrun field (above). For this test, the metric used to quantify seismic repeatability was determined by dividing, or normalizing, the root-mean-square (RMS) of the difference trace by the average of the root-mean-squares of the input traces.[11] Multiplying the normalized root-mean-square (NRMS) by 100 gives %NRMS. NRMS quantifies results of various types of noise, including positioning errors and random noise. The lower the NRMS, the more likely it becomes that subtle reservoir changes may be observed. In the Heidrun case, the low NRMS of 15% indicates that the repeatability is high enough to confidently attribute changes in the seismic sections to changes in the reservoir.

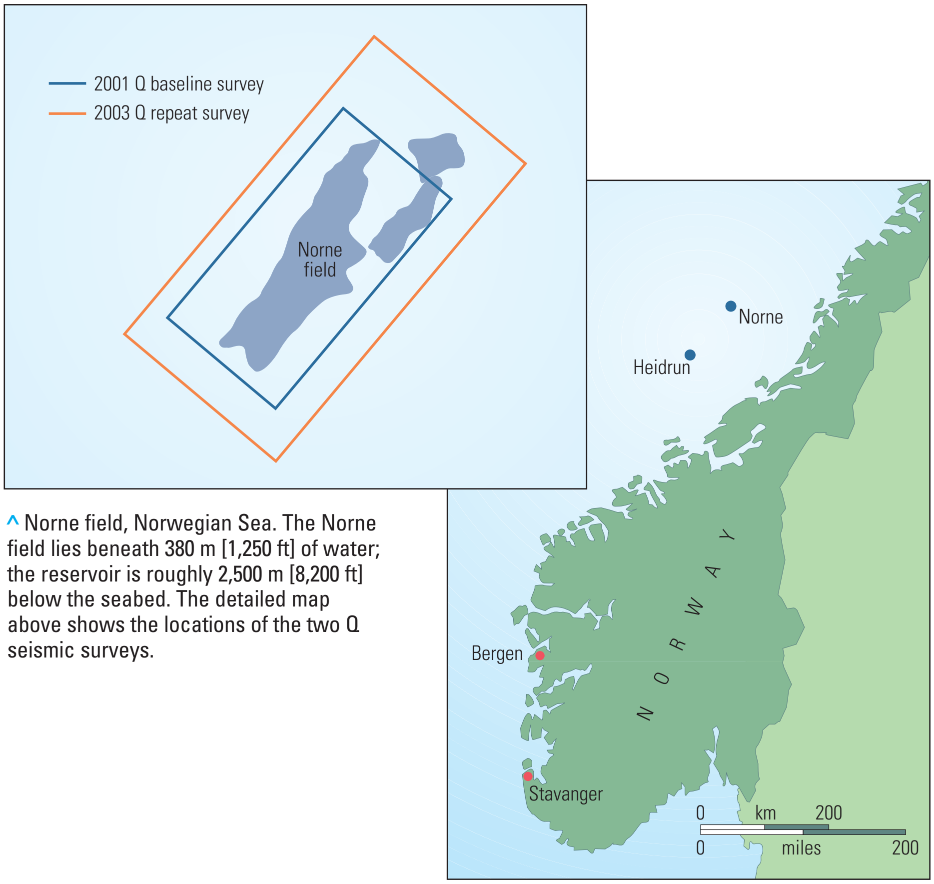
In addition to acquisition technology that minimizes noise and improves positioning, the processing provided with a Q-Marine survey is relatively simple because the inherent repeatability of Q data eliminates the need for special processing to match the surveys. Statistical cross-matching is not necessary, unlike with ordinary seismic data. Perturbations of the phase and amplitude of the seismic signal during acquisition are corrected deterministically only once. The simplified processing contributes to shorter project cycle times, which have a favorable impact on cash flows. Timely intervention to increase production and maximize reserve recovery depends on real-time or near real-time data delivery.

Meeting the Norne Challenge

Service companies and oil and gas producers operating in the North Sea and the Norwegian Sea face many obstacles in their quest to develop and manage fields efficiently and economically. Weather and sea conditions are often harsh, and the subsurface geology is complicated. Not surprisingly, these challenges have spurred the field of seismology significantly. In the mid-1990s, a pioneering application of time-lapse seismic monitoring took place in the Gullfaks field, operated by Statoil.[12] Time-lapse surveys of Gullfaks and other Statoil-operated fields have contributed to identification of reserves valued at US$ 750 million and selection of 34 additional well locations.[13]

Several years have passed since the Gullfaks surveys, and in that time, use of time-lapse surveying has become almost routine for Statoil. The company has time-lapse seismic data covering approximately 75% of the fields it operates. Feasibility studies of time-lapse surveys are carried out for every field the company operates, beginning in the field-development stage and recurring at two-year intervals thereafter. The studies address the theoretical potential of time-lapse technology by examining the rock physics using cores, logs and seismic data; scientists and engineers also determine how often a repeat survey may be worthwhile. Most of the feasibility studies demonstrate that the cost of time-lapse surveys is a small fraction of their value in terms of minimizing development-drilling costs and in recovering additional hydrocarbons.[14] The company reaps extra value from time-lapse surveys that identify undrained pockets of hydrocarbons that can be targeted for infill drilling.

The Norne field offshore Norway epitomizes many of the challenges of economically producing oil and gas. Discovered by operator Statoil and partners in 1991, and now operated by Statoil with partners Petoro, Hydro, Eni and Shell, this one billion-barrel [160 million-m^3] field has been producing oil and gas since 1997 and 2001, respectively, from 12 wells in lower and middle Jurassic sandstones (right).[15] Currently in decline, daily production of approximately 20,000 m^3/d [126,000 B/D] of oil and approximately 5 million m^3 [177 MMcf] of gas is supported by water injection through seven wells into the oil zone, and gas injection through one well into the gas cap. The produced hydrocarbons flow to a floating production, storage and offloading vessel (FPSO) moored in the middle of the field. Before installing the FPSO, however, Statoil acquired a conventional towed-streamer seismic survey in 1992 that covered the entire Norne field.



^ Norne field, Norwegian Sea. The Norne field lies beneath 380 m [1,250 ft] of water; the reservoir is roughly 2,500 m [8,200 ft] below the seabed. The detailed map above shows the locations of the two Q seismic surveys.

Statoil decided early in the life of the Norne field to acquire time-lapse seismic data to optimize field development by monitoring the movement of oil and gas in the reservoir, paying special attention to the oil/water contact (OWC). As part of that effort, the company also wanted to compare reservoir-simulation results with time-lapse seismic data.

A critical aspect of time-lapse seismic technology is ensuring that the differences between the seismic surveys represent actual changes in the reservoir rather than differences in how the surveys were acquired. The Norne field presented special problems in accomplishing this goal. For example, the presence of the FPSO meant that seismic acquisition vessels would not be able to pass directly over the central part of the field, but would need to go close to the FPSO to cover that critical area.

To address all aspects of time-lapse survey project planning, WesternGeco and Statoil acquisition specialists and geophysicists prepared an integrated project design (IPD) study. This study focused on design issues to ensure that the Q system would offer higher quality data than a conventional seismic survey. In the case of Norne, the main concern was repeatability of the 85-km^2 [33-sq mile] survey.

Analysis of the 1992 conventional 3D survey, well data and oceanographic information over Norne field helped the project-planning team optimize acquisition parameters, such as source-array design; recording parameters; streamer configuration, lengths, separations and depths; and the effect of sea currents on source and receiver positioning. The study also established metrics for assessing the technical results of the surveys. Geophysicists analyzed existing seismic data and vertical seismic profiles (VSPs) to understand the bandwidth and noise characteristics of the survey area.[16] The geophysicists were able to predict seismic response, resolution and optimal offsets in the new datasets by building an accurate earth model.

The IPD study used the results from the first two Q repeatability test swaths acquired over Norne in 2001 and reservoir production histories to provide critical information for modeling the expected changes in reflectivity due to changes in saturation and pressure. The IPD study also evaluated whether the reflectivity changes would be detectable between 2001 and 2003. The modeling results indicated that there would be a low level of noise and that the expected time-lapse signal would be visible after fewer than two years of oil and gas production.

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11. For more on seismic repeatability and NRMS: Kragh E and Christie P: "Seismic Repeatability, Normalized RMS, and Predictability," *The Leading Edge* 21, no. 7 (July 2002): 640, 642–647.
12. For more on Gullfaks time-lapse seismic applications: Najjar NF, Strønen LK and Alsos T: "Time-Lapse Seismic Programme at Gullfaks: Value and the Road Ahead," *Petroleum Geoscience* 9, no. 1 (February 2003): 35–41.

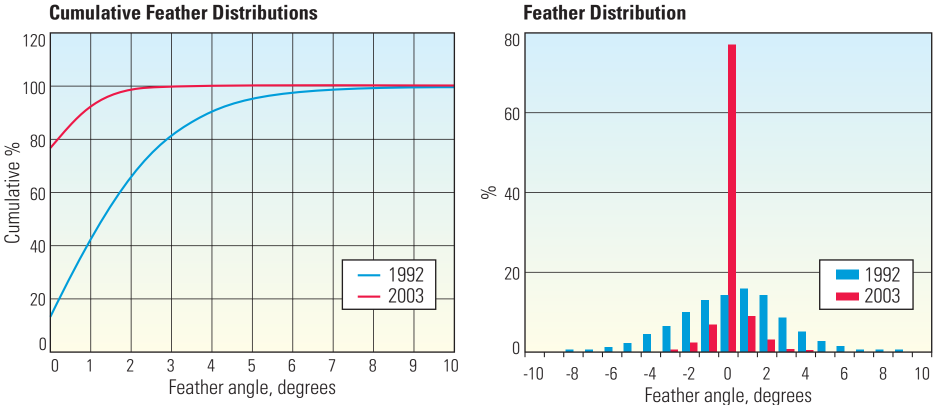
    Alsos et al, reference 2.

    Pedersen et al, reference 1.
13. Pickering S and Waggoner J: "Time-Lapse Has Multiple Impacts," *Hart's E&P* 76, no. 3 (March 2003): 54–56.
14. Other companies have had similar experiences. Shell Expro saved approximately US$ 27 million by not drilling an injection well after investing approximately US$ 3 million in time-lapse seismic studies of its Gannet fields: Kloosterman HJ, Kelly RS, Stammeijer J, Hartung M, van Waarde J and Chajecki C: "Successful Application of Time-Lapse Seismic Data in Shell Expro's Gannet Fields, Central North Sea, UKCS," *Petroleum Geoscience* 9, no. 1 (February 2003): 25–34.
15. For more on Norne field: http://www.statoil.com/STATOILCOM/SVG00990.nsf/0/3008D0315EC731C741256657004F6CEB?OpenDocument (viewed June 15, 2004).
16. A vertical seismic profile, or VSP, is a class of borehole seismic measurements used for correlation with surface seismic data, for obtaining images of higher resolution than surface seismic images and for looking ahead of the drill bit. Purely defined, VSP refers to measurements made in a vertical wellbore using geophones inside the wellbore and a source at the surface near the well. In the more general context, VSPs vary in terms of well configuration, number and location of sources and geophones, and how they are deployed. For more on VSPs: Arroyo JL, Breton P, Dijkerman H, Dingwall S, Guerra R, Hope R, Hornby B, Williams M, Jimenez RR, Lastennet T, Tulett J, Leaney S, Lim T, Menkiti H, Puech J-C, Tcherkashnev S, Burg TT and Verliac M: "Superior Seismic Data from the Borehole," *Oilfield Review* 15, no. 1 (Spring 2003): 2–23.

    Hope R, Ireson D, Leaney S, Meyer J, Tittle W and Willis M: "Seismic Integration to Reduce Risk," *Oilfield Review* 10, no. 3 (Autumn 1998): 2–15.

    Christie P, Dodds K, Ireson D, Johnston L, Rutherford J, Schaffner J and Smith N: "Borehole Seismic Data Sharpen the Reservoir Image," *Oilfield Review* 7, no. 4 (Winter 1995): 18–31.

^ Acquiring seismic data near the Norne FPSO. The *Geco Topaz* towed seismic streamers within 40 m [131 ft] of the Norne FPSO. The outermost streamer is trailing the orange buoy on the right of the photograph.



^ Impact of steered streamers on feather control. Repeatability of time-lapse surveys depends heavily on limiting streamer departure from previous surveys. Feathering in the 1992 survey, which used conventional streamers, was as high as 9° (blue). The 2003 survey with Q-Fin systems (red) limited feathering to no more than 3°; 90% of the shots had feathering less than 1° and 99% of the shots had feathering less than 2°.

Finally, the project-planning study also addressed safety concerns, including the expected weather conditions and prevailing currents. The acquisition team developed contingency plans and rehearsed for events such as loss of propulsion by the acquisition vessel. Although such an event is unlikely, the presence of the FPSO meant that a drifting vessel would pose a significant hazard.

The initial, or baseline, Q survey was acquired in less than three weeks during August 2001. The *Geco Topaz* acquisition vessel towed six 3,200-m [10,500-ft] streamers with 50 m [164 ft] of separation. Steering fins were placed at 400-m intervals along the streamers.

A two-vessel undershoot by the *Topaz* and the *Western Pacific* minimized the repeatability "hole" in the seismic survey around the Norne FPSO. Undershooting is a special technique designed to acquire seismic data beneath surface obstructions, including production platforms and environmentally sensitive areas. Streamer steering with the Q-Fin system made it possible to acquire data within 40 m [131 ft] of the Norne FPSO (top). Therefore, both Q surveys provided clear images of the center of the reservoir, located beneath the FPSO.

In June 2003, the *Topaz* acquired the first monitor, or repeat, Q-Marine survey, making Norne the first field to have time-lapse Q-Marine data. Acquisition included undershooting with the *Western Inlet*. Ongoing operations in and around Norne required cooperation and care. The survey planners developed time-sharing arrangements to cease acquisition every two days while the Norne FPSO offloaded to a tanker. Time-sharing also allowed an ocean-bottom cable (OBC) survey to be acquired tens of kilometers away at Heidrun field without interference by the powerful seismic sources used in the Norne survey. Unlike the 2001 survey, steering fins were placed at 300-m [1,000-ft] intervals along the streamers for the 2003 survey to afford greater steering capability.

The 2003 monitor survey was quickly compared with the 2001 baseline survey. As part of quality-control efforts during acquisition, the survey crew monitored ambient noise to ensure that subtle changes in signal from the previous survey would be discernable and preserved. Within days of the end of acquisition, Statoil was able to use the data to determine the location of the OWC, evaluate the progress of water injection and update the reservoir model to revise horizontal infill-drilling plans.

A major factor in the success of the time-lapse acquisition program at Norne was the steered streamers, which reduced streamer feathering and dramatically improved repeatability of the data (left). A key repeatability metric, NRMS, showed the value of Q data (next page, top). Seismic sections also confirmed the difference in repeatability between the conventional survey and the Q surveys (next page, bottom).

Fast-track processing of Q data aboard the acquisition vessel is simplified because of the stability and similarity of the time-lapse datasets. Because of the high repeatability of the acquisition system and the deterministic processing, the Q data did not require any cross-match filtering. Therefore, onboard data-processing specialists were able to complete fast-track processing of the Norne survey 10 days after the survey was completed; further processing to determine the difference in relative acoustic impedance was completed in two days.[17]

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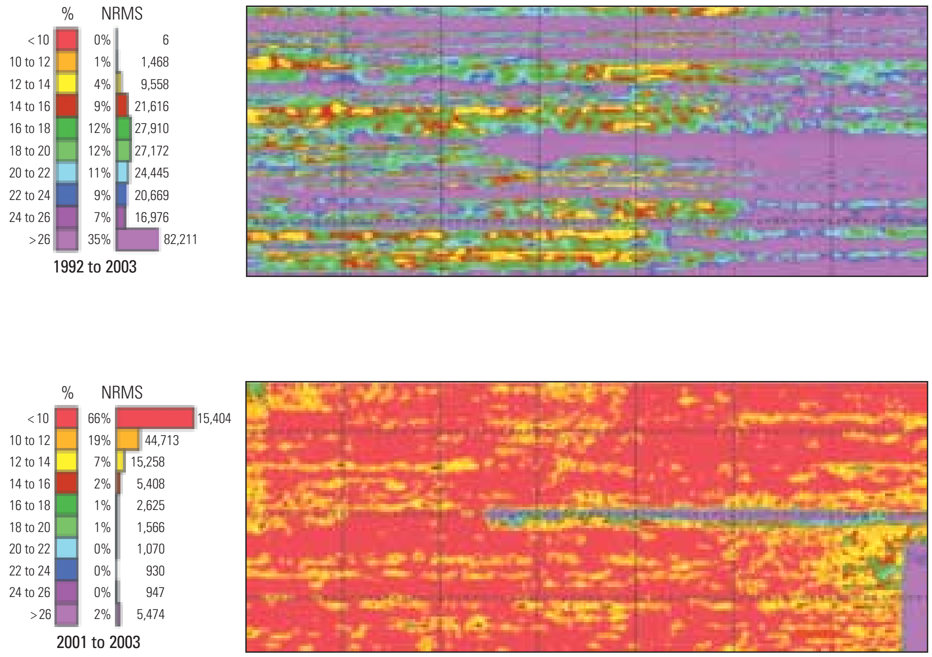
[17] Acoustic impedance is the product of density and seismic velocity, which varies among different rock layers. The difference in acoustic impedance between rock layers affects the reflection coefficient, or how much seismic energy is reflected rather than transmitted.

[18] Surface related multiple elimination (SRME) is currently the best demultiple method for removing the multiple—the seismic energy reflected more than once—generated by the sea surface. Kirchhoff prestack migration is a method of seismic migration that uses the integral form of the wave equation. Amplitude variation with offset (AVO) analysis examines variation in seismic reflection amplitude with change in distance between shotpoint and receiver. AVO responses may indicate differences in lithology and fluid content in rocks above and below the reflector.

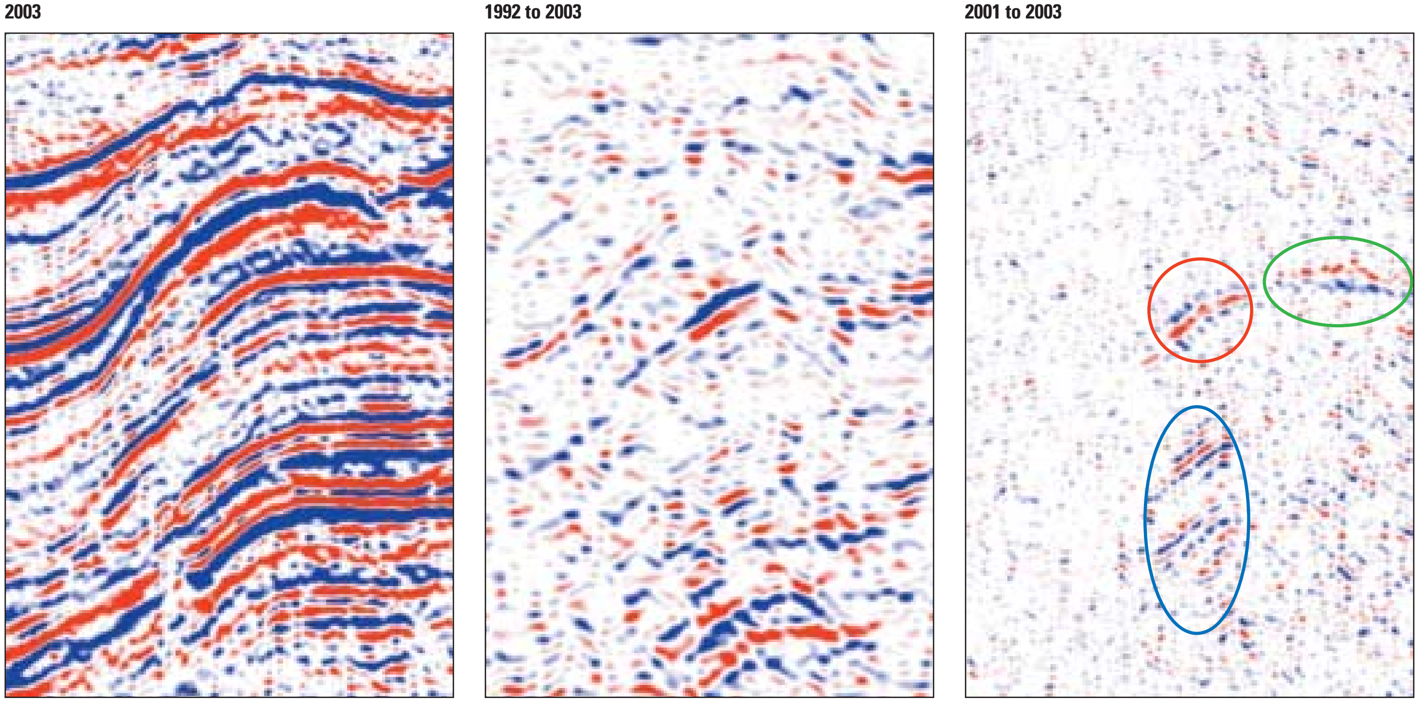
Subsequent detailed processing of the Norne surveys onshore ensured that maximum benefit was derived from the data. Although the interpretation of the final processed data did not differ greatly from that of the fast-track processing, the final processing, including surface-related multiple elimination (SRME) and Kirchhoff prestack migration, offered better definition of the time-lapse signal and allowed for time-lapse amplitude variation with offset (AVO) analysis on fully migrated gathers.[18]

Immersive visualization enhanced interpretation of the Norne data. Seismic interpreters were able to color-code changes in acoustic impedance between surveys to highlight places in the reservoir in which water replaced oil and to interpret movement of the OWC. These interpretations helped the asset team understand time-lapse effects and simplified well planning.

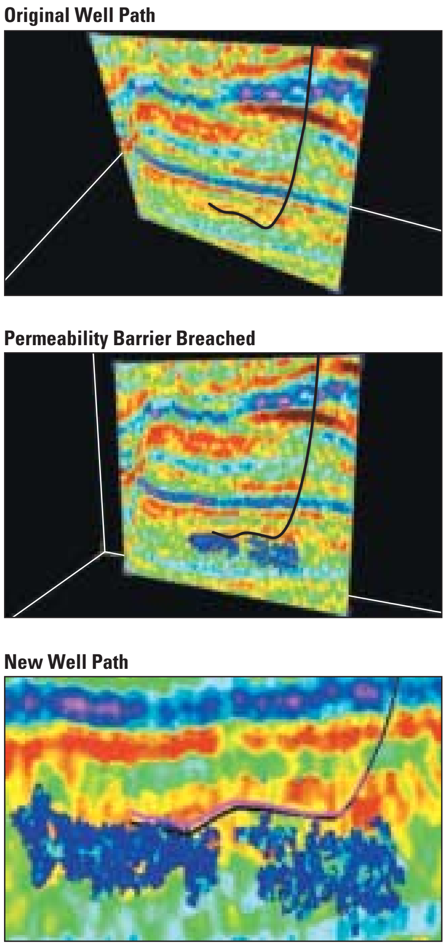
The well path Statoil originally planned landed in an area where the seismic data changed between the 2001 and 2003 surveys, suggesting that the OWC had already breached a horizontal permeability barrier and that the proposed well would intersect water-bearing reservoir. By moving the horizontal well path laterally and 20 m [66 ft] shallower, Statoil was able



^ NRMS in conventional and Q surveys. Between the 1992 conventional survey and the 2003 Q survey, NRMS from 2000 to 2800 ms, a volume that includes the reservoir interval, exceeded 26% in 35% of the seismic volume, as indicated by the purple patches on the NRMS section (*top*). Between the 2001 and 2003 Q surveys (*bottom*), 66% of the seismic section had less than 10% NRMS.



^ Seismic repeatability in conventional and Q surveys. A seismic section from the 2003 Q survey (*left*) shows strong reflectors. The difference section between the 1992 conventional survey and the 2003 Q survey (*middle*) reveals several strong reflectors, but no clear indication of changes in the reservoir. The difference section between the 2001 and 2003 Q surveys (*right*) clearly indicates parts of the reservoir that have changed. The area in the green oval might be experiencing a reduction in gas saturation due to production. Pressure in the reservoir in the red circle is increasing because of water injection. The blue oval shows a velocity pulldown—an apparent low spot produced by low seismic velocity in the overlying rocks—due to water injection above. The pore pressure has increased and the velocity has decreased, reducing the rock stiffness in the overlying interval.



^ Impact of time-lapse seismic data on well planning. Statoil planned to drill a sidetrack well to tap reserves isolated by a horizontal permeability barrier (*top*). The blue near the bottom of the middle seismic section indicates an area where water has replaced oil, and suggests that the oil/water contact (OWC) at the top of the blue area has already breached the permeability barrier. The new well path (pink line), 20 m higher and drilled away from the OWC, successfully minimized the risk (*bottom*).

to produce oil, saving US$ 29 million—the cost of drilling another horizontal sidetrack (above).

In addition to improving well planning, engineers were able to adjust production and injection rates, and to observe movement of the waterflood front within days of acquiring the data.

Ultimately, Statoil seeks to increase recovery from 40% to 52% and to extend the life of the Norne field beyond 2015. Statoil plans to continue using the Q system for time-lapse seismic acquisition. The company will acquire a third Q survey of the Norne field in 2004, approximately 12 months after the previous monitor survey.[19] The Heidrun field, initially surveyed using the Q system in 2001, will also undergo another round of Q seismic acquisition during 2004.

Reservoir Management Through Seismically Enhanced Simulation

Interpretations of reservoir pressure, saturation and fluid contacts from time-lapse seismic data contribute to production enhancement by optimizing well placement and by improving production and injection operations. The data and interpretations also complement reservoir-simulation efforts. Reservoir engineers have performed history-matching using production data for years. History-matching involves iteratively modifying certain parameters in a reservoir model until the simulation model matches the production history established from the individual wells in a field. Rigorous history-matching helps scientists and engineers predict future well and field performance. The resulting reservoir simulation is detailed and accurate near the wells, but limited in accuracy by the number and location of wells in the reservoir and by the complexity of the reservoir model. Seismic surveys provide data in the vast reservoir spaces between wells, but lack the vertical resolution of well data.

Several independent workflows involving time-lapse data can yield qualitative interpretations in reservoirs over time. For example, it is possible to use changes in seismic amplitude or other seismic attributes discerned from time-lapse data to update static reservoir models. This is especially relevant when the time-lapse signal highlights flow barriers or flow paths, such as faults or fractured zones. The updated static model can then be used for simulation based on the production history.

Another, more quantitative approach involves mapping changes in reservoir properties using time-lapse seismic data. For example, the time-lapse signal might indicate changes in pressure or fluid saturation. These changes can be calibrated to the time-lapse signal by building a rock physics model that describes the relationships between seismic data and petrophysical parameters in the reservoir. These petroacoustic models can then be incorporated into reservoir simulations.

History-matching using time-lapse seismic data and production data is a relatively recent extension of traditional reservoir simulation. This new technique quantitatively integrates production data with time-lapse seismic data and helps the asset team understand, predict and manage reservoir changes.[20]

Simultaneous history-matching of production and seismic data offers tremendous potential for reservoir management by combining the detailed information from individual wells with the expansiveness of seismic surveys. This process involves quantitative analysis and output of reservoir pressure and saturation matched to the seismic signal and the well data (next page). In contrast, traditional reservoir simulation deals solely with production data from wells; time-lapse seismic data commonly are calibrated to pressure and saturation, but are not matched with production data. The history-matching technique using time-lapse seismic data closes these gaps.

Like reservoir simulation, history-matching with time-lapse seismic data is a time-consuming process that requires clusters of computers, so

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[19] Eiken O: "Improvements in 4D Seismic Acquisition," *World Oil* 224, no. 9 (September 2003): 23–27.

[20] For more on history-matching using time-lapse seismic data: Gosselin O, Aanonsen SI, Aavatsmark I, Cominelli A, Gonard R, Kolasinski M, Ferdinandi F, Kovacic L and Neylon K: "History Matching Using Time-Lapse Seismic (HUTS)," paper SPE 84464, presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA, October 5–8, 2003.

[21] Inversion is a mathematical process by which data are used to generate a model consistent with the data. Surface seismic data, vertical seismic profiles and well log data can be used to perform inversion, the result of which is a model of Earth layers and their thickness, density, and compressional- (P-) and shear- (S-) wave velocities.

[22] Waggoner JR, Cominelli A, Seymour RH and Stradiotti A: "Improved Reservoir Modelling with Time-Lapse Seismic Data in a Gulf of Mexico Gas-Condensate Reservoir," *Petroleum Geoscience* 9, no. 1 (February 2003): 61–72.

Waggoner JR, Cominelli A and Seymour RH: "Improved Reservoir Modeling with Time-Lapse Seismic in a Gulf of Mexico Gas-Condensate Reservoir," paper SPE 77514, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.

[23] Lygren M, Fagervik K, Valen TS, Hetlelid A, Berge G, Dahl GV, Sønneland L, Lie HE and Magnus I: "A Method for Performing History Matching of Reservoir Flow Models Using 4D Seismic Data," *Petroleum Geoscience* 9, no. 1 (February 2003): 85–90.

[24] Pickering and Waggoner, reference 13.

[25] For an example from the Gulf of Mexico: Kratchovil T, Bikun J, Tixier C, Zirczy H, Beattie T, Bilinski P, Tchouparova E, van Luik K and Weaver S: "The Auger 4-D Case Study: Exploiting a Gulf of Mexico Turbidite Field by the Use of Time-Lapsed Seismic Surveys," presented at the 2004 AAPG Annual Convention, Dallas, Texas, USA, April 18–21, 2004.

Shirley K: "4-D Augurs Well for Auger Field," *AAPG Explorer* 25, no. 5 (May 2004): 14, 16.

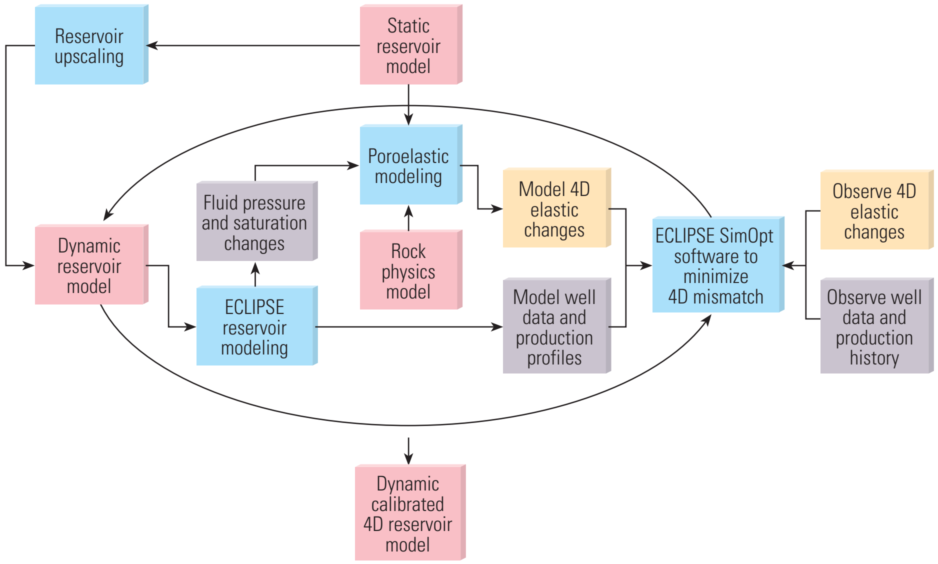
[26] For an example from the North Sea: McInally AT, Redondo-López T, Garnham J, Kunka J, Brooks AD, Stenstrup Hansen L, Barclay F and Davies D: "Optimizing 4D Fluid Imaging," *Petroleum Geoscience* 9, no. 1 (February 2003): 91–101.

[27] Eiken, reference 19.

Other experts estimate the value of time-lapse seismic data in individual fields at tens to hundreds of millions of dollars: de Waal H and Calvert R: "Overview of Global 4D Seismic Implementation Strategy," *Petroleum Geoscience* 9, no. 1 (February 2003): 1–6.

Shell Expro anticipates a 5% increase in ultimate oil recovery from its Gannet fields as a result of time-lapse seismic investments: Kloosterman et al, reference 14.

History-Matching Refinement Cycle



^ History-matching using time-lapse seismic data. The process begins with a static reservoir model, time-lapse seismic data (abbreviated as 4D in the flow chart) and production data from wells. The history-matching refinement cycle minimizes the mismatch between seismic data, the dynamic reservoir model, and other measured and modeled changes using ECLIPSE SimOpt model calibration software and ECLIPSE reservoir simulation software.

careful constraints are necessary to avoid excessive iterations. Well logs undergo petrophysical evaluation, editing and calibration against seismic data. Seismic horizons must be mapped in the baseline and repeat surveys, and both sets of seismic data must undergo inversion.[21] The inverted seismic datasets are converted from seismic traveltime to depth.

After depth conversion, scientists and engineers try to match the acoustic impedance of the seismic surveys. By building a petroacoustic model and then performing forward modeling, changes in saturation and pressure become apparent. Finally, the changes in saturation and pressure determined from seismic interpretation and modeling are combined with production data to match the seismic history and the production history.

Specialized ECLIPSE SimOpt model calibration software helps accomplish the history-matching faster and with higher quality outcomes. In one run, this software determines the sensitivity of simulation results to many input parameters so that the importance of each parameter can be taken into account in the simulation model. By understanding the importance of various input parameters, engineers and scientists avoid spending time on insignificant parameters and instead focus on the parameters that will have the greatest impact on the simulation. The software also helps constrain poorly known parameters within reasonable ranges to reduce the number of time-consuming history-matching cycles.

When one works with time-lapse seismic data in isolation, a persistent question is whether the difference between surveys represents more than changes in saturation and pressure, such as rock compaction. Using time-lapse seismic data in history-matching helps answer this question because time-lapse seismic data calibrate the simulation models to better quantify fluid-related changes.

History-matching is under way using the first repeat Q-Marine seismic surveys from the Norne field. The Q system, including single-sensor technology, calibrated sources and steerable streamers, provides the necessary high resolution, high repeatability and high reliability that are prerequisites for a quantitative, history-matched analysis. Key objectives of this analysis include identifying practical workflows for time-lapse seismic analysis and evaluating the benefits of quantitative versus qualitative analysis.

Scientists and engineers have integrated time-lapse seismic data with production history-matching in other innovative ways. For example, a recent study on a complicated gas-condensate reservoir in the Gulf of Mexico evaluated the effects of pressure changes on the time-lapse signal; other studies typically involve the effects of saturation changes rather than pressure.[22] In the North Sea, experts are history-matching time-lapse seismic data and reservoir flow models to evaluate fluid flow.[23] A novel aspect of this work is the evaluation of the fluid transmissibilities of faults, which would be difficult to determine without combining seismic and production data. As seismic repeatability improves and more surveys are repeated, history-matching of seismic and production data will play an even greater role in reservoir management.

Time Will Tell

Oil and gas exploration and production have always carried significant risk, but the petroleum industry has prospered by rapidly adopting advanced technologies that help manage the risks and reduce the uncertainties. Seismic technology has been a key to improved exploration success rates over the past few decades, and is now an established technology for reducing risk and uncertainty in subsequent stages in the lives of oil and gas fields.

As the Norne example demonstrates, the Q acquisition and processing methodology helps operators get more information and profitability from their seismic investments. Time-lapse seismic surveys, calibrated with well-log and borehole seismic data, help identify fluid types, map fluid saturations and flow barriers between wells, and enable operators to make more informed drilling, development and reservoir-management decisions.[24]

As with many other oilfield technologies, integration enhances the value of time-lapse seismic data. For example, integrating data from production logs and permanent downhole pressure gauges with seismic data may reveal undrained compartments and additional reservoir potential.[25] Integration of core data with legacy seismic surveys also improves reservoir monitoring and management.[26]

Some experts view the potential value of time-lapse seismic data on the order of billions of dollars in increased hydrocarbon recovery.[27] To extract this value routinely, seismic repeatability must continue to improve. Improved repeatability will allow oil and gas companies to see time-lapse signals within repeat surveys in a matter of months rather than years. This shorter time frame will facilitate more active and timely reservoir management.

Although this article concentrated on technology and operations, there is another crucial ingredient in successful application of time-lapse seismic data: skilled personnel to model, plan, acquire, process, integrate and interpret the data. The powerful combination of people and technology is ushering in a new era of reservoir management. —GMG