Until recently, time-lapse seismic monitoring was considered unproven for tracking the movement of an oil-water contact (OWC). However, Statoil petrophysicists working on sonic logs from the Gullfaks Field in the Norwegian North Sea uncovered changes in log response that were favorable for seismic monitoring. Open hole logs from three wells drilled through the original OWC, compared to logs from wells drilled into water-flushed areas, showed consistently higher velocities in the water-filled zones than in those filled with oil.

Periodic logging in an observation well showed that the OWC was rising 13 m per year. Analysis revealed that sonic logs above the OWC were repeatable from one year to the next, while below the OWC, sonic velocities increased where water had displaced oil. If borehole sonic waves could detect saturation changes at the well scale, perhaps seismic waves could do the same across the whole field.

Predicting success. Seismic response to a change in fluid properties at a reflector can be predicted through forward modeling, if elastic properties of the rock and fluids are known. Long-studied relationships, originally published by Gassmann, can predict density and seismic velocity through what is called fluid substitution – knowing the properties of a rock filled with the original fluid and the properties of the new fluid allows computation of the properties of the newly filled rock.

Fluid substitution requires knowledge of the density, porosity, and bulk and shear moduli of the rock frame, the bulk modulus of the grains making up the rock, and the density and bulk modulus of the two fluids, all at the pressure and temperature conditions of the reservoir. Rock grain properties are usually measured in the laboratory, while the rock frame and fluid properties may be measured in the lab or inferred from core data and petrophysical analysis.

Figure 1. Modeling seismic response to different fluids using log input. Normal-incidence compressional (NIP) synthetic seismograms computed for oil-filled Tarbert Sand (track 2) and water-filled sand (track 5) show different characteristics at the top reservoir reflection. Real seismic traces, however, are the result of stacking traces from many angles of incidence. The synthetic oil- and water-filled equivalents to the real stacking process are in traces 3 and 6, respectively. The seismic section near the well is shown in track 4. The seismic trace at the well location is in track 7, repeated several times for ease of comparison with the synthetics.

Figure 2. Effects of Gullfaks structural complexity on seismic data and modeling. The steep change in sea bottom depth over the field, strong reflectors overlying the target, and a highly faulted target combine to make imaging and characterization of Gullfaks reservoir properties difficult.
from borehole measurements of compressional and shear velocities, porosity, and density.

The computed compressional velocity can be used to model the anticipated change in seismic response at the top of the reservoir, in this case, the top of the Tarbert Sand (Figure 1). When the rock is filled with oil, a normal-incidence reflection has a very slight positive response. When rock is filled with water, the reflection shows a greater negative response. The difference in modeled responses to oil-filled and water-filled reservoirs becomes more pronounced when the effects of seismic trace stacking are taken into account.

This seismic modeling has assumed that the Tarbert Sand is completely filled with either oil or water, but intermediate stages of saturation can also be modeled. If the OWC is an abrupt change in saturation that occurs over just a few feet or meters — as was probably the case when the reservoir was at equilibrium before any fluids were produced — the contact may also be a seismic reflector. After years of production, the saturation change may occur over a wide transition zone, and may or may not appear as a discontinuity to seismic waves.

Data acquisition. Predicting that before-and-after pictures will look different just sets the stage for seismic snapshots. Seismic modeling usually assumes that survey parameters in the baseline and monitor surveys are identical. Parameters include receiver and source positions, source signature, and any directivity or coupling effects associated with the environment. In the past, this has limited most surveys to land, where source positions can be marked and receivers permanently implanted.

In the marine environment, permanent sensors have been used for decades, but usually for earthquake and other seismicity detection. Only recently have ocean bottom cables been permanently installed over reservoirs for repeat seismic surveying. Permanent sensors for marine seismic monitoring are still in the experimental stage. And though they will likely ease some problems associated with imperfectly repeated experiments, they cannot promise the same weather, currents or other temporal conditions that affect all marine surveys.

But this does not mean that marine monitoring is infeasible. Monitoring the quality of the seismic signal and other essential measurements, such as navigation accuracy, during acquisition, allows identification of those perturbations that can be accepted, those that can be compensated for, and those that require a new experiment.

The following example shows how the combination of high-quali-
Marine acquisition and innovative interpretation techniques have helped Statoil optimize development of the Gullfaks Field.

**Monitoring Gullfaks production.** Under the current production plan, begun in 1986, Gullfaks will produce 53% of 579 million m³ of original oil in place. About half the remaining oil could be produced with infill wells, but locating them optimally and reducing costs continues to be a challenge.

Development has been hampered by the complexity of the faulted reservoir structure. However, new seismic data and results from development wells have improved knowledge and refined fault mapping. Carefully planned data acquisition and flexible drilling programs brought a sound understanding of reservoir properties early in the development.

Reservoir simulation has been used extensively to continually evaluate production and development options. But even with detailed reservoir models, engineers don’t know where a fluid front is until it arrives at a well. By tracking fluid-contact fronts before they get to wells, reservoir engineers are able to take action to avoid potential problems. With seismic monitoring, the project team (geophysicists, geologists, petrophysicists and reservoir engineers) will be able to model reservoir drainage and optimize future production.

Several sets of seismic data have been acquired over Gullfaks. The initial data were 2-D lines that were 2-km apart. The first 3-D survey was acquired in 1979 and a second in 1985. Despite marked improvement in quality in the second survey, and careful reprocessing in 1992, the data are still very complex due to variable reflectivity and the highly faulted target zone (Figure 2).

A pilot reservoir volume, in an area with high porosity (averaging 34%) which is known to be favorable for seismic monitoring, was chosen to test the technique’s ability to map changes in the oil-water distribution.

Three production platforms created an acquisition challenge for the 1995 monitor survey: seismic vessels had to navigate to avoid the platforms, leaving a gap in the 3-D volume. The missing volume was filled in by undershooting; a source vessel shot to a separate receiver vessel positioned on the other side of the platform. However, the acquisition geometry, and therefore the raypaths and seismic energy reflected at the target, were different from the rest of the survey (Figure 3).

Researchers are testing ways of compensating the undershoot data for the difference in the amount of energy reaching the target. One method that appears to give good results is to assume that the overburden does not change with time. This translates into the constraint that the total energy contained in the seismic trace from the sea bottom to the top of the reservoir be constant from one survey to the next. A calibration function, or match filter, can be applied to the low-energy 1995 data to fulfill this constraint.

**Interpretation innovations.** The goal in interpreting seismic monitoring data is to extend the reservoir knowledge at well locations into the interwell volume; i.e., to predict reservoir properties where there are no wells. Good data at Gullfaks con-
sist of basic rock and fluid information — whether the reservoir sand is present, and if so, the type of fluids present.

To extend this information away from the well into the reservoir, the reservoir volume, especially the top surface, must be accurately interpreted from the 3-D seismic. In the case of Gullfaks, this surface is the top of the high-porosity Reservoir sand, and the interpretation includes all faults that intersect it (Figure 4). The top picked in 1985 is a positive-polarity reflection, and the same feature was interpreted in the 1995 data. Automatic horizon-picking software is used to achieve the required accuracy and avoid inconsistencies introduced through manual interpretation.

The second step is to characterize the seismic data, at or surrounding the well location, that correlate with the information on reservoir properties at the well. The seismic information is captured in attributes. For the Gullfaks interpretation, at least 20 different instantaneous and volume attributes were computed for the reservoir sand.

Next, the attributes are examined for correlation with a number of classes of reservoir properties. Three were identified in the pilot area: (1) oil-filled sand; (2) water-filled sand; and (3) gas-filled sand. Correlation of a class with a set of attributes is determined by the closeness with which members of the class are located in a multidimensional cluster plot with the attributes as axes (Figure 5). The multidimensional space thus created is called attribute space. When members of a class lie close together, or the cluster is tight, they correlate well with that collection of attributes. The class members have a distribution in attribute space that can be quantified statistically.

In addition to mutual proximity, the members of a class must also be well separated from members of other classes. Several combinations of attributes must be tested to obtain a set of attributes that are sensitive to the class properties and able to distinguish the classes from one other (Figure 6).

Several methods in multivariate statistical and neural network analysis have been tested to achieve classification. The classification could be done without any prior knowledge of the field, using unsupervised classification methods based on natural

Figure 5. Creating an attribute space plot. In this example, the goal is to classify the attributes in the areas marked by the triangle, square, and circle. Each shape contains many data points, plotted as points with that shape on the corresponding graph. When only two attributes (amplitude and polarity) are examined (top), the resulting 2-D plot fails to distinguish squares from triangles. When three attributes (amplitude, polarity, and phase) are used (bottom), all three shapes can be distinguished because the phase attribute now distinguishes squares from triangles. On real seismic data, any number of attributes may be examined.

Figure 6. Attribute space plots showing good (left) and bad (right) correlation between reservoir properties and attributes. Reservoir property values from well data are color-coded dots with oil in red, gas in yellow, and water in blue. Values are plotted as points in the space defined by different attributes.
clustering techniques. The number of classes to find must then be specified. Another possibility is to combine the attributes with well log information in supervised classification. The result will be maps showing the fluid distribution along the reservoir.

To find this correlation between well log information and seismic attributes in supervised classification, only seismic data near wells have been used. The classification system has been trained to recognize desired reservoir properties in the seismic data through a set of attributes. For the Gullfaks seismic interpretation, when the attribute set with sufficient discrimination has been found, that next step is classification of the attribute surfaces according to the three classes of reservoir properties. The classification system has been trained on the 1985 data and applied to both 1985 and 1995 data.

Final results show how the fluid distribution has changed in the reservoir sand over the course of 10 years (Figure 7). The fluid distribution changes inferred from seismic monitoring agree with the expected drainage in the area. Simulated fluid saturations for 1985 and 1995 were extracted from the drainage simulation models, which have been history-matched to well data (Figure 8).

These simulated saturation distributions show the same general features as the seismic interpretations. Oil has been drained from the westernmost fault blocks, and from the western edges of the two central fault blocks. A fault in the northern portion of the center block appears, however, to be isolating oil and gas from the southern part of the fault block, where the oil sweep appears to be effective.

Based on the positive seismic monitoring study, two major decisions have been taken toward modifying Gullfaks development. First, a new 3-D survey was acquired in 1996 (together with simultaneous logging, pressure and saturation distribution in key wells) to cover the rest of the field. The new 3-D survey also covers satellite fields to the south and will be the baseline survey for future monitoring in those fields. Second, a new extended-reach well is being drilled from the C Platform in the eastern part of the field, where production from zones immediately below has declined. The well is designed to tap multiple compartments identified as containing bypassed oil.

Now that Statoil has confirmed the feasibility of monitoring in the prime conditions of the Tarbert Formation in Gullfaks, other more challenging application await. Deeper reservoir layers with lower porosity might also be candidates for monitoring, pushing the technique to its limits.

**Seismic monitoring will change with time.** Faster and higher quality 3-D data acquisition have reduced the leading edge of the field.
the investment in seismic monitoring to a level where costs are offset by the increase in production associated with a better understood reservoir. But seismic monitoring is still in its infancy (remember 3-D seismic technology took 10 years to become established). More field studies and further developments are needed to prove the value of additional knowledge brought by seismic monitoring.

Further work is required in many areas to bring this technique into routine practice. Repeatability of acquisition may never be perfectly realized, but the limits and tolerances of acquisition differences should be better appreciated. There will probably not be a single acquisition scheme that will have universal application for seismic monitoring, but rather a range of solutions to cover a spectrum of different reservoirs.

Some failures of early monitoring attempts have been attributed to the “incidental” nature of time-lapse surveys (i.e., most 3-D surveys are acquired without any intention of comparing the results to a later monitor survey). With routine seismic monitoring on the horizon, though, there is great interest in ensuring that baseline surveys have all the information imaginable to extend their value as long as possible.

More research and experimentation with permanent sensors, in ocean-bottom cables and in boreholes, will advance knowledge of hardware limitations and bring down costs.

Work remains to be done on understanding the relationships between seismic attributes and rock and fluid properties. Currently, finding the right attributes for a desired reservoir property is a time consuming interpretation project requiring an expert. Forward modeling may help predict which attributes are useful for a given fluid change or rock type, and might allow some automation of the interpretation process.

Central to integrating the efforts of geologists, geophysicists, petrophysicists and reservoir engineers is the model — a common earth model (Figure 9) — that can be refined at every stage of reservoir management. Continued refinements of seismic monitoring will be driven by the teams charged with optimizing recovery from existing fields. These teams require methods that allow them to understand and also control reservoir behavior. With that as a goal, seismic monitoring may one day become the most powerful of reservoir management tools.

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