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Geophysical reservoir monitoring feasibility study in a Central Saudi Arabian oil field

Aldo L. Vesnaver, Michael K. Broadhead and Isidore J. Bellaci

ABSTRACT

The Central Arabian field of this study is part of a trend of oil fields primarily producing from Permian sandstone reservoirs. The most productive zone, in the upper part of the reservoir, is characterized with good porosity and permeability, an aeolian depositional environment, and producing zones that tend to be laterally and vertically heterogeneous. The reservoir sandstone lenses are interspersed with low porosity/permeability siltstones. We examined the feasibility of water-saturation surveillance by geophysical means that could help to better produce the field and unravel certain production challenges; hence, time-lapse seismic (4-D) was considered. Using modeling, we argue that time-lapse seismic is a low probability candidate for successful reservoir monitoring of water saturation in this field. We also discuss other techniques that are potential alternatives, such as micro-seismicity, magnetotellurics and borehole gravity, comparing the relative merits and limitations of these methods as applicable to this field. Finally, we conclude with the potential impact of improved reservoir characterization, via integration of more seismic information into the reservoir model.

INTRODUCTION

Geophysical reservoir monitoring methods can be a key tool for optimizing production in petroleum fields in many regions of the world. Although borehole measurements tend to be high resolution, vertically, the lateral penetration depth is usually on the order of centimeters to meters. Geophysical methods such as 3-D and 4-D seismic are dense with information laterally (albeit limited vertically), and may provide some clues to the major changes between the available wells. For example, time-lapse seismic has enjoyed many successes in the last decade, especially offshore in unconsolidated clastic reservoirs. Despite some early attempts, no clear time-lapse successes have been reported so far in Saudi Arabia, where most fields are onshore and carbonate. Recent feasibility studies performed at Saudi Aramco (see e.g. Broadhead and Ras, 2005a, b; Dasgupta, 2005; Vesnaver et al., 2005) concluded that the time-lapse signal in a major onshore carbonate field is probably too weak for reliable detection in the face of seismic data uncertainty. This conclusion was based on modeling and empirical studies with borehole log data - no definitive field test has yet been done, though plans for a repeated vertical seismic profile (VSP) survey with permanently mounted downhole sensors are underway (Dasgupta, 2005).

The difficulty for the application of 4-D seismic in Saudi Arabian reservoirs is primarily two-fold: (1) rock properties, and (2) data quality. The rigid matrix and fast velocities make the time-lapse signature weak, which would require very reliable and repeatable data. Repeatability is always a major issue in land acquisition. Minor changes in positioning and soil moisture content produce clear changes in coupling and local velocities. Although positioning and permits for access is easier in the desert, the near-surface anomalies introduce new challenges. The data quality is limited by near-surface complexities, such as sand dunes, wadis and karsting. The poor signal/noise ratio often requires the fold of the seismic data to approximate 1,000, otherwise some target horizons cannot be interpreted. Near-surface and intrabed multiples often overwhelm primaries, as proven by VSPs and sonic-log calibrations. Recent tests in the Arabian Peninsula showed that the time-lapse noise of VSP data exceeds 10% of the total signal energy, within a time span of a few days only. Since VSP data quality is always much superior than surface seismic, we can assume this value as a very optimistic threshold for conventional time-lapse surveys on land. The overburden changes due to seasonal effects are relevant too. The change in the velocity of compressional P-waves in dry versus wet shallow formations may exceed 500 meters/second (m/s), producing time-lapse anomalies comparable to those ones expected at the reservoir.

In order to optimize the likelihood of success, an area with several oil fields in Central Arabia was chosen for this study. The field has a clastic reservoir with relatively good-quality seismic data and has a good distribution of calibration wells (Figure 1). A further reason for this choice was its size: it is large enough for a major business impact, but not large enough to have a slow depletion rate (according to current production technology and market conditions). In this way, we could observe appreciable flood front movement over a reasonable seismic repeat interval.

GEOLOGICAL BACKGROUND

The studied area is located about 118 miles (190 km) south of Riyadh (Figure 1). This area is about 37 miles (60 km) in length, and varies in width from 6 miles (10 km) at some fields to about half a mile (1 km) at other fields. The area includes six principal hydrocarbon accumulations in a Lower to Middle Permian sandstone of arid continental origin. This producing area was discovered in 1989, and production started in 1994. Our study focused on the largest field in this region.

The reservoir consists of a lower fluvial sandstone member, and upper Aeolian sand lenses embedded in a tight siltstone background. The carbonate caprock is the seal. The primary reserves are found in the middle unit, which is the focus of our study. This main producing unit is composed of several aggradational cycles. Individual cycles show upward-cleaning characteristics, most commonly starting with transgressive lacustrine-associated sabkha, and interdune facies in the lower parts, followed by aeolian and ephemeral fluvial channel deposits in variable proportions. The vertical aggradation of playa lake and over-bank deposits resulted locally in the developments of very thick siltstones flanked by aeolian and/or fluvial channel sandstones. The aeolian and fluvial channel sandstones constitute the principal reservoir facies.

The depositional environment described above induced significant lateral heterogeneities in the target reservoir, and areal compartmentalization is identified from the performance history. In addition, some impermeable layers, often with a thickness of only a few feet, also introduce vertical compartments. These thin layers are not detectable with surface seismic resolution, but are apparent from well data.

The oil in the reservoir is the unusual combination of high gravity (approximately 50° API) with a low Gas-to-Oil Ratio (GOR). This has the impact of lowering the compressibility change of the rock in response to water saturation. The low GOR reduces the compressibility (and consequently also the P-wave

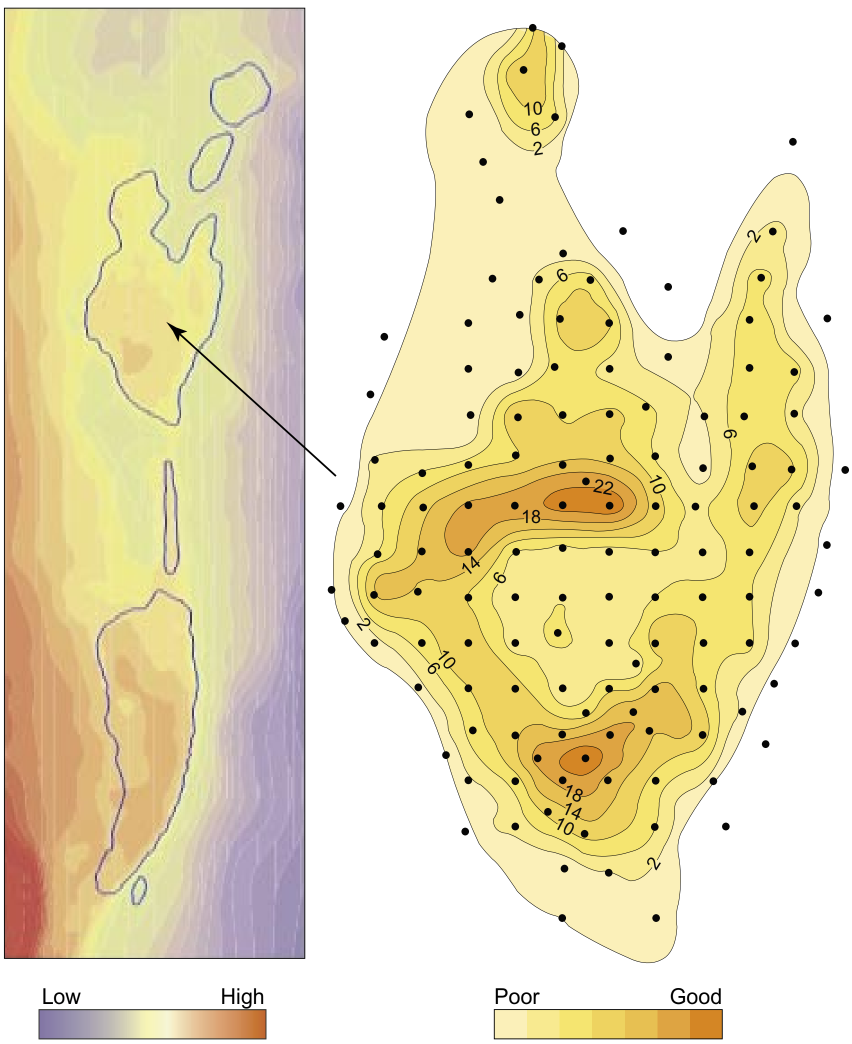

Figure 1: Field boundaries in the study area trend are traced in blue (left), and wells at the selected field are indicated by dots (right).

velocity) change caused by production. Moreover, the injected water as well as the formation water are both low salinity, so we do not expect a major density difference to contribute to the seismic response when the oil is displaced by water influx or injection. Since the first order driver of seismic amplitude (and, hence, time-lapse signature) is acoustic impedance, which is the product of P-wave velocity and bulk density, we already have lowered expectations.

Other positive factors gave hope that they might offset the impact of these fluid characteristics; specifically: (1) the high porosity of the reservoir; (2) the relatively good quality of the available 3-D seismic data (Figure 2); and (3) the relatively unconsolidated nature of the clastics for the reservoir. At the target level, the real seismic traces reasonably match the synthetic one obtained by well logs. Also, when considering acoustic impedance at other wells, the match between data from surface seismic and wells is good (Figure 3). This is quite encouraging, and contrary to other fields where multiples and a low signal/noise ratio can make this correlation questionable. Therefore, it was decided to quantify these different contributions in order to understand whether their effects would be observable in a reasonable time span with current technologies.

Fluid Substitution and Seismic Modeling

Fluid substitution analysis is the process of modeling the effect of changing the reservoir fluid conditions on P-wave velocity, shear S-wave velocity and bulk density. Then, the effect of these changes for the velocities and density on the seismic response can be computed by seismic modeling. The fluid substitution analysis was done for a well in the field, and was confined to the main reservoir level. Effects due to pressure changes might also exist, but their influence is limited and neglected here.

We first performed a fluid substitution analysis to correct for invasion effects, and then another to simulate full-sweep conditions (which we assumed to be a water saturation of 80%) from the water drive. Other possible factors, such as irreducible water, could further decrease this optimistic assumption. Figure 4 displays the results of a fluid substitution analysis performed in the oil leg. Results are only shown for acoustic impedance, which is P-wave velocity multiplied by density. The

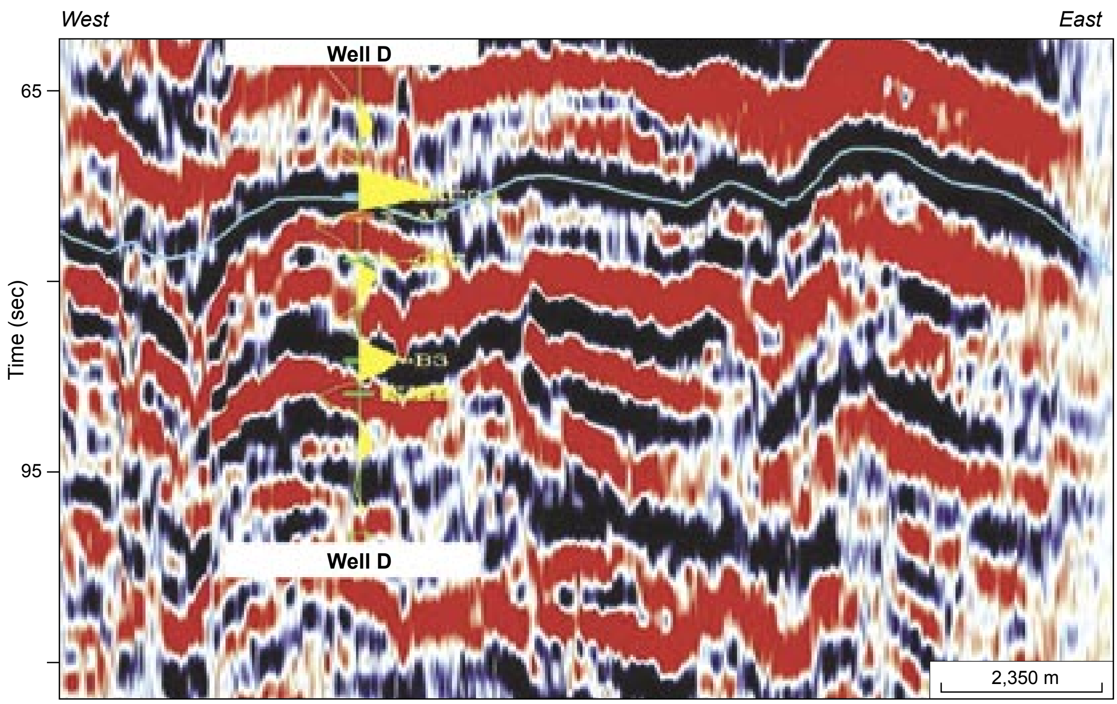

Figure 2: Detail of a seismic section at the target. The superimposed yellow trace is the synthetic seismogram estimated from well logs.

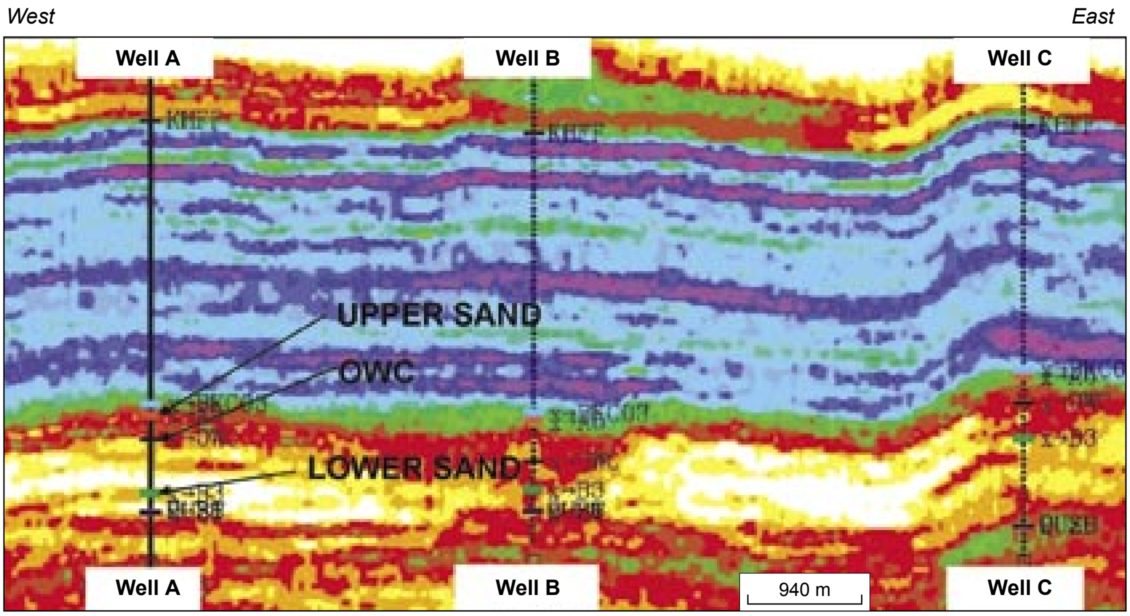

Figure 3: Detail of a seismic impedance section passing through three wells. Low impedance (white and yellow) corresponds to good quality of the reservoir. The Upper and Lower Sandstone are, respectively, the Top and the Base of the reservoir.

mean percent change in acoustic impedance between *in situ* and full-sweep conditions is predicted to be about 3.3%. This is very marginal.

We know that the density difference reduced the signature - but what of our expectation that compressibility effects would improve the signal due to the unconsolidated nature of the reservoir? It turns out the predictions for Gassmann fluid effects show a sensitivity to background velocity - the higher the velocity, the lower the fluid signature. The target sandstone reservoir has a relatively high velocity (10,000–12,000 ft/s) presumably due to compaction by burial under a large stress load of hard rock. Therefore the lack of consolidation does not really improve the signal. The low consolidation itself is one of the puzzles of this field, and the explanation of inhibition of cementation due to the presence of hydrocarbons is not without controversy. Compaction effects are often observed in the North Sea, for example, where they add relevant ambiguities in the interpretation of seismic data. They make it difficult to distinguish between time-lapse effects due to compaction or pressure changes (see e.g. MacBeth et al., 2005; Meadows et al., 2005; Kvam and Landro, 2005). In the field considered here, however, the great depth of the reservoir and the rigidity of the caprock make it likely that possible compaction effects, if any, should be local and limited.

To predict the magnitude of the change on the seismic signature due to the fluid difference, we used a two half-space model and calculated the angle dependent reflection coefficients (this assumes vertical heterogeneity in the reservoir and caprock). The percentage change in PP reflection coefficient was about 5.2%, and the change in SS and PS reflection coefficients was much less. Thus, we cannot expect significant variations in the PP reflection coefficient change with angle of incidence.

Another approach to seismic modeling is the calculation of normal incidence synthetic seismograms, which takes into consideration time-delay effects (sag) and wave superposition effects. This model also allows for vertical heterogeneity. Shown in Figure 5 are the fluid-substitution effects on the logs, which have been converted to time. Red indicates *in situ* conditions (primarily oil) and blue indicates full-sweep water flood (primarily brine). A small, fluid-induced, time-shift occurs between the two fluid cases. The synthetic seismograms are also shown, along with the difference, which reflects some amplitude change, and also the time shift. Note that the difference is not confined to the zone where fluid changed: the maximum change occurs in the lowest part of the reservoir, which experienced no

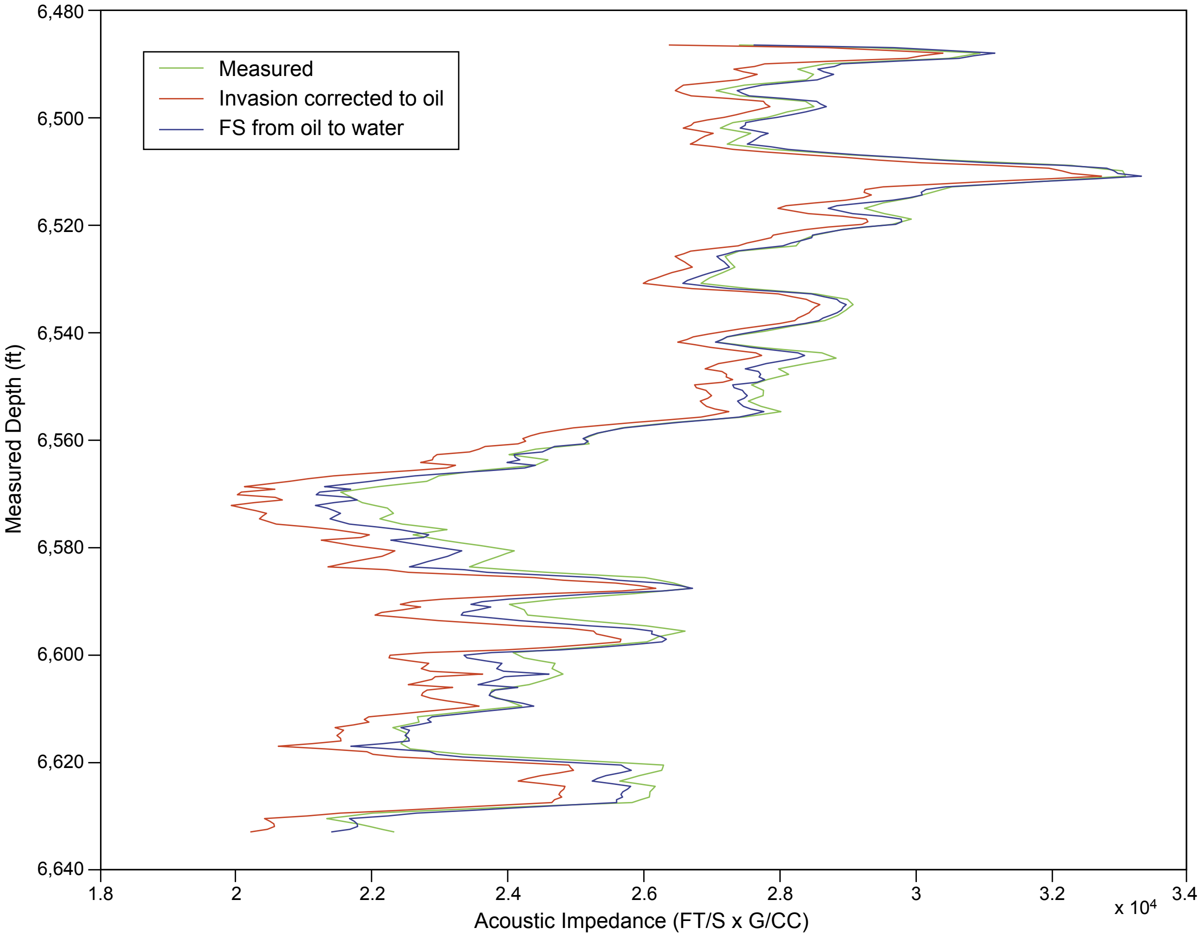

Figure 4: Fluid substitution analysis in the oil leg of the main reservoir unit, shown for acoustic impedance as a function of measured depth. The oil leg consists of the zone from the top of the upper sand to the OWC.

reservoir fluid change. We must quantify the scale of the difference seismogram relative to the scale of the original seismograms. Since we are not dealing with a single number, a simple percentage change will not suffice. We chose several different metrics, and collectively summarize their results as 12.4 + 2.7%.

Two approaches were taken to seismic modeling, and the results appear to differ by a factor of 2.5. This discrepancy is primarily due to two factors.

(1) The synthetic seismograms indicate a change due to time delay (about 1 msec) as well as an amplitude change, where the reflection coefficients calculation for the two-layer case only indicates the amplitude change. In fact, this time delay causes the largest part of the time-lapse signature to occur in the lowest formation, which is not producing in this well.

(2) The apparently significant percentage change (about 12%) in amplitude on the synthetic seismogram occurs for rather small amplitudes with respect to the rest of the seismogram (not shown). Such a change will be difficult to detect with reliability because the Signal/Noise ratio will be lower, processing will not be optimal, and confidence in any changes on a repeated survey will be low confidence. In short, we cannot reduce the significance of the time-lapse signature to one number (percentage change in acoustic impedance or seismic amplitude) - other factors must be considered, including acquisition and processing parameters, and the geological setting (e.g. the caprock rigidity mentioned above).

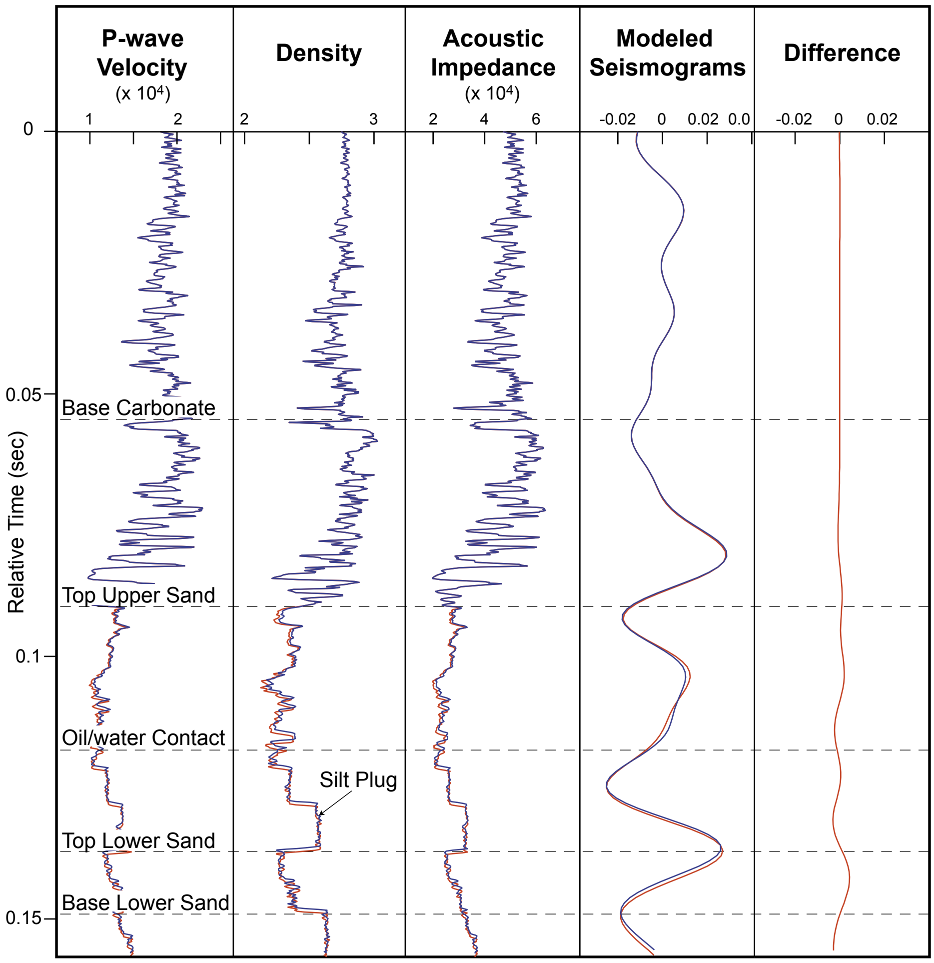

Figure 5: Modeling results (left to right): P-wave velocity; density; acoustic impedance; modeled seismograms (reverse polarity Ricker wavelet); difference. In the first four tracks, red indicates pay case, and blue indicates wet case. Note, the increase in acoustic impedance below the oil/ water contact (OWC) is due to lower porosity due to increased silt content. Just below the OWC, before the facies/lithology change, there is no visually detectable change in impedance (no fluid signature).

One might be tempted to believe that the predicted time delay could itself be exploited; however, at one millisecond, it is probably too small to be detected due to variations in repeated surveys due to acquisition and processing issues (such as statics corrections). Static time-shift corrections are a major issue in Saudi Arabia, due to a complex near-surface environment. Moreover, the statics can be time varying due to seasonal effects. This factor has been introduced recently in marine data processing (see, e.g. Vesnaver et al., 2003), but an equivalent technology for land data is still in a research and development phase.

Regardless of the predicted size of the time-lapse signature, its significance ultimately must be judged against a repeatability standard. Consider two surveys acquired in as-identical a manner as possible, and processed in nearly the same way as possible. Further, assume some cross-equalization process has been done, to further reduce (or spread out) differences. Nevertheless, some non-production related differences will usually remain. We will refer to the minimum we can reasonably expect these differences to be, on average, as the "time-lapse noise floor."

One can only assess the quantitative significance of the predicted seismic-fluid signature with respect to this "noise floor" - which has not yet been measured in our case. Considering the usual difficulties faced when dealing with land data, and the small magnitude of the amplitude portion of this signature, and considering studies elsewhere, we conclude that a marginal case exists with respect to time-lapse seismic. We would require standards of repeatability on the acquisition and processing of base and monitor surveys that are currently probably too high. Seasonal variations in near-surface conditions would have to be measured (such as by repeated up-holes) and compensated for, and this is itself a challenge in arid areas.

We recognize that the conventional wisdom in time-lapse seismic argues that modeling such as we have done, in many cases under-estimates the time-lapse signature. The logs themselves, because of the oil/water contact, show this low sensitivity directly, without Gassmann modeling, and multivariate regression analysis arrived at the same conclusion. Still, this is not conclusive due to likely invasion effects (cause by overbalanced drilling), which are difficult to assess. Also, no pressure-effects modeling was done. This was partially due to the fact that most of the large pressure changes in the field occurred earlier in its production history, and partially due to a lack of a model for P-wave velocity versus effective stress for the Permian sandstone. No feasibility study is, in itself, a replacement for actual measurements; however, considering the cost of repeated land 3-D survey acquisition, this study motivated us to look for other, perhaps more appropriate, techniques.

IF NOT SURFACE SEISMIC, WHAT ELSE?

Repeated VSP and Tomography

A negative view on the usefulness of repeated surface seismic does not necessarily preclude other seismic methods. Repeated vertical seismic profiles and cross-well surveys (tomography) were considered next. These alternative techniques rely on permanently installed receivers and sources, and therefore the data is less affected by noise and near-surface distortions. In contrast to surface seismic, the path of seismic waves in VSPs and cross-well surveys is shorter and better constrained, resulting in a better-resolved image in the space surrounding the wells. The repeatability of the signal can be further enhanced if the receivers are embedded down into the well during its completion. Nevertheless, we did not rank this option as high, especially if used alone. This is because of its high cost for a limited coverage of the reservoir volume, where workovers or new wells would be required. In addition, no new wells were planned for the field.

Micro-Seismic Technique

During the last decade, several successful experiments have been reported using an emerging technology called micro-seismicity. Fluid movement in the reservoir is governed by pressure gradients. Perturbations to this pressure field during production can induce slippage (tiny earthquakes) in micro-fractures that are in a state of critical stress, thus causing detectable micro-seisms. The signal from micro-seismic activity may be observable by current technology for magnitudes (M) of about 2 for near-surface buried receivers, and about M = 2.5 if they are located in dedicated observation wells, within a few hundred meters from the producing reservoir. The patterns of the failure points may indicate possible open or sealing faults, or just a uniform propagation of the swept area. Vidal et al. (2002) discussed the relevance of geomechanic effects for reservoir monitoring. Very recent large-scale tests in the North Sea are being carried out with many thousands of receivers, both on the sea floor and in some wells (see e.g. Barkved 2004). In the Arabian Peninsula, encouraging experiments were carried out in Oman during the last few years (Corsten et al., 2005), which are currently being published.

Although measurements using the micro-seismicity technique may not directly resolve water saturation changes, they may provide important information on fluid pathways in the study area. One concern for the application of this technique involves the weakly consolidated aspect of the reservoir (40% of the wells needed gravel packs). However the recent application of the technique to a similar reservoir in Mexico, resulted in success (Gaucher et al., 2005). For this reason, we consider this technique to be a reasonable approach to be further considered. We are deferring field tests until a micro-seismicity pilot study is completed in another field in Saudi Arabia (Dasgupta, 2005). In that case, the likelihood of success is greater because of the harder rock matrix; a lack of micro-seisms in those conditions would discourage further tests in other areas. However, successful applications were carried out also in geological conditions comparable to our study area.

Magneto-Telluric Technique

Normally, a significant difference occurs in resistivity between oil and brine, which is injected to support production in most reservoirs of Saudi Arabia. One method that can exploit this difference to obtain water saturation is the joint inversion of seismic and magneto-telluric data. In the field considered here, however, the salinity of the injected water is low, thus giving a lower-than-normal resistivity contrast between oil and injected water. Is enough differential left for this technique to be viable at this field? This question is under further study, and will require modeling.

Gravity Technique

The resolution of gravity methods is generally lower than that of electromagnetic ones. This is because the density contrast between the low-GOR oil and low-salinity brine is small and difficult to discriminate via gravity measurements. However, when used in conjunction with surface seismic, it could still add valuable information for reservoir characterization. To overcome the resolution issue, borehole gravity is being considered. Such measurements were reported in the Gulf of Mexico, Alaska, and other field in the last decade (Schultz, 1989; Knighton et al., 1999; Ander et al., 1999). Accordingly such tests are being considered for this field once additional technological advances have been made with the instrumentation. Modeling has determined that instrument sensitivity needs about an order of magnitude increase versus the available one from current technology. We assumed density changes due to the same fluid substitution percentage and rate as described above for the seismic response.

CONCLUSIONS

The preliminary assessment of this study is that no existing geophysical reservoir monitoring technology looks promising for the studied field. Additional and more comprehensive feasibility studies, involving modeling and pilot field tests are required to validate (or invalidate) this conclusion. The techniques of micro-seismicity and improved production-history matching (via a more rigorous incorporation of seismic information into the reservoir model) may offer the most promising geophysical aids to improving our understanding of this oil field trend. This conclusion is consistent with the study by Deflandre et al. (2003) who discussed the inclusion of micro-seismic data.

Production history shows that the reservoir is compartmentalized stratigraphically, and possibly by faulting. Many of these features are on a sub-surface seismic resolution scale. Nevertheless, it is possible that incorporation of some imprint of the seismic in the reservoir model (currently based only on wells) will help, due to the lateral heterogeneity. Figure 3 illustrates how seismic impedance can help identify gross lateral facies changes. A comparable good match is also observed in other wells for this area. Iterative history matching of well performance, along with the seismic and well data might lead to the desired, improved reservoir model. These techniques are not new, and lie more in the realm of traditional reservoir characterization than monitoring - however, possibly apart from micro-seismicity, we believe that this is the primary contribution that geophysics could make to improve the understanding of this field.

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ABOUT THE AUTHORS

Aldo L. Vesnaver *joined Saudi Aramco's Geophysical Technology Team in 2002. From 1983 to 2001, he worked at the Italian National Institute for Oceanography and Applied Geophysics. Aldo has held positions including Seismic Data Analyst, R&D Team Leader, and Vice Director. He completed his MSc in Physics in 1983 and PhD in Geophysics in 1990, both from the University of Trieste, Italy. Between 1985 and 1995 Aldo was Assistant Editor of "Bollettino di Geofisica Teorica ed Applicata". He has been an Associate Editor of both "Geophysics" and "Geophysical Prospecting", becoming Editor-in-Chief of the latter in 2006. He served in the SEG Global Affairs Committee as Regional Coordinator for Europe from 1999 to 2001, and as Chairman from 2005 to 2006. In 2001, Aldo co-founded the Italian EAGE-SEG Section. He is a member of the DGS, EAGE and SEG, and has published over 100 papers in international journals and conference proceedings.*

aldo.vesnaver@aramco.com

***Michael K. (Kent) Broadhead** works as a Research Geophysicist at Saudi Aramco, Dhahran, Saudi Arabia. Kent has a BS in Mathematics, an MS in Physics, and pursued additional study at the PhD level in Scientific Computing. He worked as a Geophysicist for Texaco in the US for about 12 years, as a Research Physicist for a US government laboratory for about 9 years, and has been with Saudi Aramco since 2000. Kent is a member of the SEG, EAGE and AGU. His professional interests include inverse problems, rock physics issues in seismology, signal processing, and developing uncertainty analysis methodologies in exploration/production seismology.*

michael.broadhead@aramco.com

***Isidore J. (Ike) Bellaci** has been working as a Reservoir Engineer and Petroleum Engineering Specialist at Saudi Aramco, Dhahran, Saudi Arabia since 1998. Prior to joining Saudi Aramco, Ike held various development, reservoir, operations and drilling engineering positions over a 15-year period with Atlantic Richfield Company (ARCO) in Houston, London, Bakersfield and Anchorage. Ike has a BS in Petroleum Engineering from Louisiana State University and is a member of the SPE.*

isidore.bellaci@aramco.com

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