Time-lapse (4D) seismic effects: Reservoir sensitivity to stress and water saturation

Sunday O. Amoyedo, Kurt J. Marfurt and Roger M. Slatt, The University of Oklahoma.*

Summary

Knowledge of reservoir saturation variation is vital for in-fill well drilling, while information on reservoir stress variation provides a useful guide for sand production management, casing design, injector placement and production management. Interpreting time-lapse difference is enhanced by decomposing time-lapse difference into saturation, pressure effects and changes in rock properties (e.g. porosity change in chalk reservoirs).

We analyze the stress and saturation sensitivity of the reservoir and overburden shale of Forties Field, located in the UK sector of the North Sea. While pore pressure variations have not been significant in most parts of the field, a slightly high decrease in pore pressure in a region of the reservoir has had a profound effect on both reservoir and overlying caprock. We find that strain development in the field accounts, in part, for increased reservoir sand production. We use changes in the AVO intercept and gradient calibrated with laboratory measurements to invert the time-lapse (4D) difference for saturation and pressure changes.

Introduction

The need for effective reservoir monitoring is increasing in the face of diminishing reserves and a growing desire for optimized recovery. Reservoir depletion gives rise to changes in seismic amplitude, time lag between events, Δt, strain, ε_{zz}, and compaction. Knowledge of reservoir saturation variation is vital for in-fill well drilling by targeting by-passed hydrocarbons, while analysis of reservoir stress variation provides a useful guide for sand production management, casing design and injector placement. Reservoir depletion is characterized by fluid replacement and changes in effective stress. Seismic velocities in sandstone vary strongly with changes in both water saturation and stress because of differences in fluid and elastic properties as well as changes in grain boundaries, micro-cracks and fractures (Sayers, 2010).

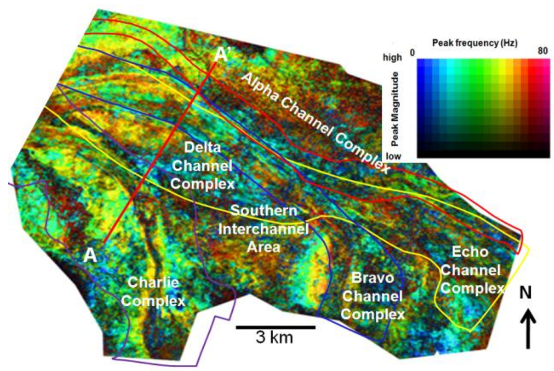

Figure 1: Forties Field channel sands- Alpha, Bravo, Charlie, Delta and Echo. Underlying the channel complexes are the Upper and Lower Main sheet sands.

Forties Field, composed of Late Paleocene sheet sands overlain by channel (Alpha, Bravo, Charlie, Delta, and Echo- Figure 1) complexes (Thomas et al., 1974), started production in 1977. Over 1.6 billion barrels of oil had been produced before the first 3D seismic survey was shot in 1988. Water saturation had increased by about 25-28%, while pore pressure decrease was of the order of 5 MPa in Charlie complex between 1988 and 2005 (Figure 2).

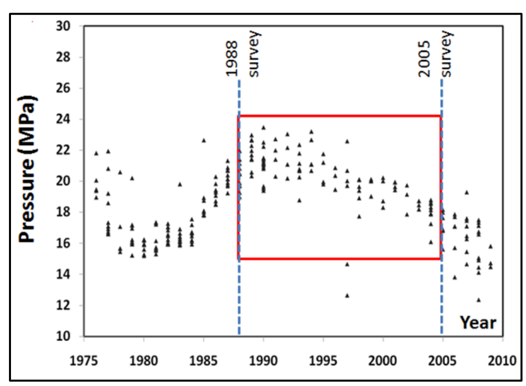

Figure 2: Forties Field pore pressure history: Charlie. The interval of interest between the two seismic surveys is marked by the red rectangle.

DOI http://dx.doi.org/10.1190/segam2012-0491.1

Seismic time lag, Δt, provides a direct indication of a change in seismic propagation velocity. The magnitude of the lag is related to the magnitude of changes in stress and saturation.

Sand production, which constitutes a major source of well failure, can be linked to a number of factors including wellbore deviation through the reservoir, grain size, poor reservoir consolidation, perforation-induced damages, capillary forces associated with water cut, flow rate, and most importantly reservoir stress resulting from pore pressure depletion. Substantial strains (> 0.2%), which can be induced by the effective and shear stress changes on the reservoir rock, are sufficient to severely degrade cohesion by breaking the small amounts of brittle grain-to-grain mineral cements as the pore pressure decreases. (Zhang and Dusseault, 2004).

Primary objectives of this study include: understanding the impact of changes in pore pressure on reservoir stress state in a poorly consolidated reservoir, AVO sensitivity to production effect, establishing a link, if any, between reservoir sand production and time-lapse effects and to invert for saturation and pressure variations using changes in AVO parameters.

We begin by estimating and removing the background (non-production related) time shift between the 1988 and 2005 seismic surveys. The background time lag was estimated at a region above the producing interval devoid of production effects. We compute the production-induced time lag by the cross correlation of the two surveys (1988 and 2005). We observe a velocity slowdown (negative velocity change) in the overburden directly above the Charlie complex, where there has been a significant variation in pore pressure. Elsewhere, the time lag was close to zero.

Our workflow involves a combination of laboratory measurements, use of fluid substitution model, AVO analysis and modifying an earlier published workflow (Landro, 2001; Landro, et al; 1999) for pressure and saturation inversion. We observe that the pore pressure-induced change in the reservoir stress state impacts mainly the total horizontal stress while the vertical stress remains largely unchanged. This is because the vertical stress greatly exceeds the horizontal stress.

We find that strain development in the field accounts, in part, for increased reservoir sand production. Our laboratory measurements and fluid substitution model show strong sensitivity of amplitude variation with offset (AVO) attributes to changes in reservoir stress and water saturation. Extending the workflow described by Landro, (2001) to account for porosity change, we decouple the seismic time-lapse difference into pressure and saturation effects.

Time-lapse effects: Rock sensitivity to production effects

Time-lapse seismic difference (amplitude, impedance differences and time lag) is a combined effect of fluid substitution and stress increase accompanying a decrease in pore pressure.

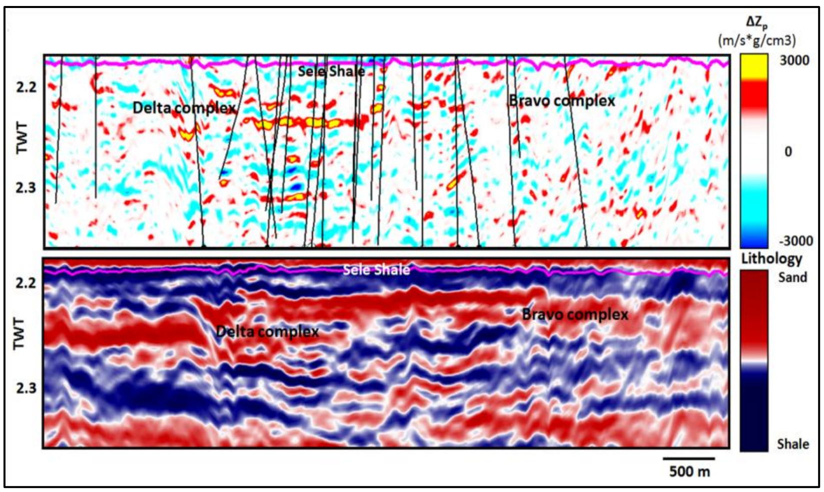

Figure 3. (upper) difference in Acoustic impedance, ΔZ_p. (lower) the corresponding lithology indicator section

The linear relation between effective and pore pressure is expressed as

$$P_e = P_o - \alpha P_p \,, \qquad (1)$$

where P_e, P_o, α and P_p represent effective pressure, overburden pressure, Biot's constant and pore pressure respectively. While fluid substitution may be effectively handled by Gassmann's model and others, understanding sandstone sensitivity to stress is far more complex, requiring

DOI http://dx.doi.org/10.1190/segam2012-0491.1

a good knowledge of the geomechanical behavior of the reservoir rock. For a laterally extensive reservoir, we define the parameter γ_v as the change in the total vertical stress, $\Delta\sigma_v$, over the change in pore pressure, Δp, expressed as:

$$\gamma_v = \frac{\Delta\sigma_v}{\Delta p} = \frac{GC_u h}{R} f\left(\frac{D}{R}\right), \qquad (2)$$

where G is the shear modulus, C_u is the compaction coefficient, h is the reservoir average thickness, R is the average lateral extent of the reservoir, while the function $f\left(\frac{D}{R}\right)$ depends on the ratio of reservoir depth to its radius (Hettema et al., 1998).

The change in total horizontal stress, $\Delta\sigma_h$, gives rise to a parameter γ_h (for an isotropic state) as pore pressure changes expressed as:

$$\gamma_h = \frac{\Delta\sigma_h}{\Delta p}. \qquad (3)$$

The change in total horizontal stress, $\Delta\sigma_h$, is defined as

$$\Delta\sigma_h = \left(\frac{v}{1-v}\right)\Delta\sigma_v + \alpha\Delta p\left(1-\frac{v}{1-v}\right), \qquad (4)$$

where v is the Poisson's ratio. With these definitions, equation 3 can therefore be written as:

$$\gamma_h = \frac{\Delta\sigma_h}{\Delta p} = \left(\frac{v}{1-v}\right)\gamma_v + \alpha\left(1-\frac{v}{1-v}\right). \qquad (5)$$

Using the Forties Field reservoir properties, we observe that γ_v is on the order of 6.58 x10^{-3}. This is insignificant when compared with γ_h, which is of the order of 0.72. This observation allows us to attribute the velocity changes within the reservoir and overburden to changes in the total horizontal stress and saturation. The decrease in total horizontal stress, which in this case is of the order of the pore pressure change, might be significant enough to induce fault slippage in the overburden.

Analysis and discussion

Reservoir monitoring is a vital tool in field development as a source of information on changes in reservoir fluid saturation, drainage pattern and stress changes. Our ability to interpret time-lapse differences effectively is enhanced by decoupling them into their components saturation and pressure effects. Knowledge of reservoir saturation variation is vital for in-fill well drilling and fluid front movement, while reservoir stress variation provides useful information for sand production management, casing design, carbon storage management and injector well placement.

Time-lapse seismic effects are sometimes pressure dominated, such as Magnus Field, (Watts et al., 1996), or saturation dominated, such as Gullfaks Field, (Landro et al., 1999), and the Draugen Field, (Gabriels et al., 1999, Veire et al., 2007). In other cases, time-lapse differences are a combined effect of both pressure and saturation changes. In such cases it is necessary to decouple production related differences (Tura and Lumley, 1999; Landro, 2001; Lumley et al., 2003).

Recalling the linearized PP reflectivity, Landro (2001) assumed showed that the change in reflectivity associated with fluid substitution can be written as :

$$\Delta R^F(\theta) \approx \frac{1}{2}\left(\frac{\Delta\rho^F}{\rho} + \frac{\Delta\alpha^F}{\alpha}\right) + \frac{\Delta\alpha^F}{2\alpha}\tan^2\theta, \qquad (6a)$$

while change in reflectivity attributable to pressure change, assuming that density is unchanged, can be written as

$$\Delta R^P(\theta) \approx \frac{1}{2}\frac{\Delta\alpha^P}{\alpha} - \frac{4\beta^2}{\alpha^2}\frac{\Delta\beta^P}{\beta}\sin^2\theta + \frac{\Delta\alpha^F}{2\alpha}\tan^2 \qquad (6b)$$

where the P-velocity, S-velocity, change in P-velocity (due to pressure, $\Delta\boldsymbol{P}$, and saturation change, $\Delta\boldsymbol{S}$), and change in S-velocity (due to pressure change) are denoted as α, β, $\Delta\alpha^P$, $\Delta\alpha^F$ and $\Delta\beta^P$.

For highly compacting reservoirs (e.g. chalk reservoirs), where saline water interaction with carbonate can weaken the reservoir matrix), the 4D difference could be dominated primarily by changes in porosity, $\Delta\Phi$. Therefore, accounting for this change in reservoir elastic properties becomes necessary in the interpretation of time-lapse difference.

Modifying Landro's (2001) equation, we can write that the relative changes in compressional, shear velocities and density as:

$$\frac{\Delta\alpha}{\alpha} \approx n_\alpha\Delta S + j_\alpha\Delta P + m_\alpha\Delta P^2 + k_\alpha\Delta\Phi, \qquad (7a)$$

$$\frac{\Delta\beta}{\beta} \approx n_\beta\Delta S + j_\beta\Delta P + m_\beta\Delta P^2 + k_\beta\Delta\Phi, \text{ and} \qquad (7b)$$

DOI http://dx.doi.org/10.1190/segam2012-0491.1

$$\frac{\Delta\rho}{\rho} \approx n_\rho \Delta S + j_\rho \Delta P + k_\rho \Delta\Phi\ , \qquad (7c)$$

where $\Delta\Phi$ represents the change in porosity as the reservoir stress state changes. Solving equations 6a-c we can show that for a highly compacting reservoir,

$$\left[m_\propto - nc_7 + k\left(\frac{n_\propto}{k_\propto}c_7 - \frac{m_\propto}{k_\propto}\right)\right]\Delta \boldsymbol{P}^{2}\ \left[j - nc_6 + k\left(\frac{n_\propto}{k_\propto}c_6 - \frac{j_\propto}{k_\propto}\right)\right]\Delta \boldsymbol{P} + \left[nc_5 + \ k\ \left(\frac{2\,\Delta b_2}{k_\alpha} + \frac{n_\propto}{k_\propto}\,c_5\right)\right] - \Delta b_0 = 0 \qquad (8a)$$

Given a change in pressure, ΔP, from the solution of equation (8a), we can further show that the change in water saturation is :

$$\Delta \boldsymbol{S_w} = \ c_5 - \ c_6 \Delta \boldsymbol{P} - \ c_7\ \Delta \boldsymbol{P}^{2}, \qquad (8b)$$

while the change in porosity can be written as:

$$\Delta\boldsymbol{\Phi} = \frac{2}{k_\propto}\Delta b_2 - \frac{n_\alpha}{k_\alpha}\Delta \boldsymbol{S} - \frac{j_\alpha}{k_\alpha}\Delta\mathbf{P} - \frac{m_\alpha}{k_\alpha}\Delta \boldsymbol{P}^{2}\ , \qquad (8c)$$

where the scalar quantities n_α, n_β, n_ρ, m_α j_α, j_β, j_ρ, and m_β are determined from laboratory measurements and the fluid substitution model, while k_α, k_β and k_ρ can be determined from coupled reservoir simulation and geomechanical model. $c_1 - c_7$ are combinations of the above scalar quantities

We adopted the above methodology to invert for pressure and saturation changes in Forties Field between 1988 and 2005. However, we assumed that the quantities k_α, k_β and k_ρ are negligible for this case study i.e. stress-porosity sensitivity is low within the range of pore pressure changes in the interval of study). Figure 4 shows the pressure and saturation change maps at the top of the reservoir. Significant variation in saturation is observed at the various well locations across the field. Production records show that over 600 million barrels of oil were produced across the field during this interval of investigation, which accounts for the observed variation. On the other hand, the pressure map reveals little or no change in reservoir pressure in the non-Charlie complexes but a higher variation of pressure in the Charlie complex. This result is validated by the reservoir pressure measurements, which indicates a 5 MPa decrease in pore pressure in the Charlie complex.

Conclusion

Significant changes in reservoir pore pressure can impact not only the reservoir but also the overlying shale. Direct effects may include increased sand production within the reservoir and dilation of the overburden. Changes in AVO attributes provide an indication of reservoir sensitivity to changes in pore pressure and water saturation. Time-lapse (4D) differences inverted for saturation and pressure effects and calibrated by well and production data, provide an additional and reliable tool for reservoir pressure monitoring.

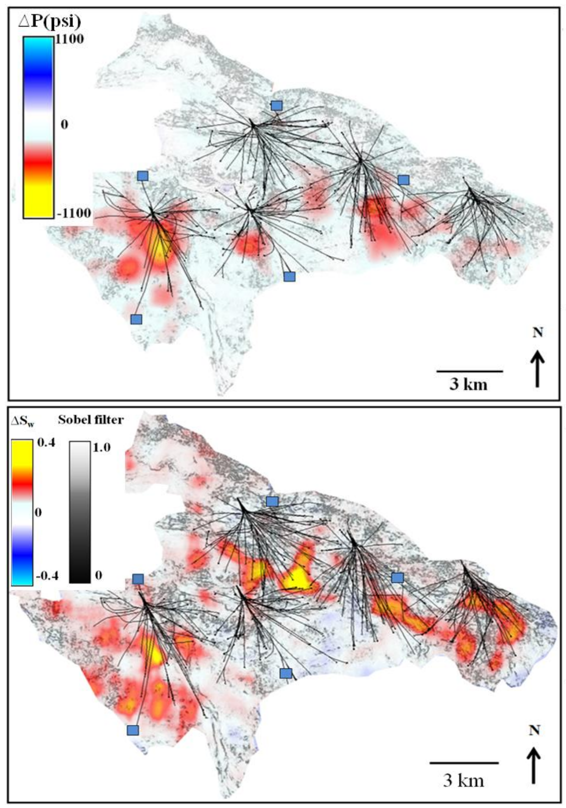

Figure 4: Time-lapse difference (1988-2005) inverted for changes in pressure (upper) and water saturation (lower). An edge detection attribute, Sobel filter, is shown in the background. Injector wells are shown in blue squares.

Acknowledgement: The authors will like to thank Apache North Sea Ltd for providing the data for this study and granting the permission to publish the results. Funding was provided by the OU AASPI consortium members.

Corresponding author: amoyedo@gmail.com

DOI http://dx.doi.org/10.1190/segam2012-0491.1

http://dx.doi.org/10.1190/segam2012-0491.1

EDITED REFERENCES

Note: This reference list is a copy-edited version of the reference list submitted by the author. Reference lists for the 2012 SEG Technical Program Expanded Abstracts have been copy edited so that references provided with the online metadata for each paper will achieve a high degree of linking to cited sources that appear on the Web.

REFERENCES

Gabriels, P. W., N. A. Horvei, J. K. Koster, A. Onstein, and R. Staples, 1999, Time-lapse seismic monitoring of the Draugen field: 69th Annual International Meeting, SEG, Expanded Abstracts, 2035–2037.

Hatchell, P., and S. Bourne, 2005, Rocks under strain: Strain-induced time-lapse time shifts are observed for depleting reservoir: The Leading Edge, **24**, 1222–1225.

Hettema, M. H. H., P. M. T. M. Schutjens, B. J. M. Verboom, and H. J. Gussinklo, 1998, Production-induced compaction of sandstone reservoirs: The strong influence of field stress: European Petroleum Conference, SPE, SPE 50630, doi: 10.2118/50630-MS.

Hill, P. J., and G. V. Wood, 1980, Geology of the Forties Field, U.K. Continental Shelf, North Sea, *in* M. T. Halbouty, ed., Giant oil and gas fields of the decade 1968–1978: AAPG Memoir 30, 81–93.

Landrø, M., 2001, Discrimination between pressure and fluid saturation changes from time-lapse seismic data: Geophysics, **66**, 836–844.

Landrø, M., and R. Janssen, 2002, Estimating compaction and velocity changes from time-lapse near and far offset stacks: 64th Conference and Exhibition, EAGE, Extended Abstracts, P036.

Landrø, M., O. A. Solheim, E. Hilde, B. O. Ekren, and L. K. Strønen, 1999, The Gullfaks 4D seismic study: Petroleum Geoscience, **5**, 213–226.

Landrø, M., and J. Stammeijer, 2004, Quantitative estimation of compaction and velocity changes using 4D impedance and travel-time changes: Geophysics, **69**, 949–957.

Landrø, M., H. H. Veire, K. Duffault, and N. Najjar, 2003, Discrimination between pressure and fluid saturation changes from marine multi-component time-lapse seismic data: Geophysics, **68**, 1592–1599.

Lumley, D., D. Adams, M. Meadows, S. Cole, and R. Ergas, 2003, 4D seismic pressure-saturation inversion at Gullfaks field, Norway: First Break, **21**, no. 9, 49–58.

McIntyre, B., T. Hibbert, D. Keir, R. Dixon, T. O'Rourke, F. Mohammed, A. Donald, L. Change, A. Syed, and V. Biran, 2009, Managing drilling risk in a mature North Sea field: Offshore Europe Oil and Gas Conference and Exhibition, SPE, SPE 124666.

Papamichos, E., I. Vardoulakis, J. Tronvoll, and A. Skjaerstein, 2001, Volumetric sand production model and experiment: International Journal for Numerical and Analytical Methods in Geomechanics, **25**, 789–808, doi: 10.1002/nag.154.

Sayers, C. M., 2010, Geophysics under stress: Geomechanical applications of seismic and borehole acoustic waves: SEG Distinguished Instructor Series No. 13.

Sayers, C. M., and P. M. T. M. Schutjens, 2007, An introduction to reservoir geomechanics: The Leading Edge, **26**, 597–601.

Shuey, R. T., 1985, A simplification of the Zoeppritz equations: Geophysics, **50**, 609–614.

Thomas, A. N., P. J. Walmsley, and D. A. L. Jenkins, 1974, Forties Field, North Sea: AAPG Bulletin, **58**, 396–406.

Tura, A., and D. E. Lumley, 1999, Estimating pressure and saturation changes from time-lapse AVO data: 69th Annual International Meeting, SEG, Expanded Abstracts, 1655–1658.

Veire, H. H., H. G. Borgos, and M. Landrø, 2007, Stochastic inversion of pressure and saturation changes from time-lapse multi component data: Geophysical Prospecting, **55**, 805–818.

Watts, G. F. T., D. Jizba, D. E. Gawith, and P. Gutteridge, 1996, Reservoir monitoring of the Magnus field through 4D time-lapse seismic analysis: Petroleum Geoscience **2**, 361–372.

Zhang, L., and M. B. Dusseault, 2004, Sand-production simulation in heavy-oil reservoirs: SPE 89037.

DOI http://dx.doi.org/10.1190/segam2012-0491.1