Th N106 12

The 4D seismic signature of gas in thin-bedded geology: results from an outcrop analogue model

M.-D. Mangriotis* (Heriot-Watt University) & C. MacBeth (Heriot-Watt University)

SUMMARY

Numerous examples of reservoir fields from continental and marine environments involve thin-bedded geology, yet, to our knowledge, the inter- relationship between thin-bedded geology, fluid flow and seismic wave propagation remains unexplored. This paper focuses on the 4D seismic signature of gas saturated thin layers, and addresses the challenge of identifying the relevant scales and properties which correctly define the geology, fluid flow and seismic wave propagation in the field. Based on the study of an outcrop analogue for a thin-bedded turbidite, we model the time lapse seismic response to gas saturation changes for different levels of model scale, from fine scale geological grid to upscaled coarse flow simulation grids. Our results show that multiples and converted waves vastly contribute to the measured amplitudes in the case of thin-bedded geology. Hence, any forward/inverse modelling from the flow simulation to the seismic domains involved in quantitative 4D has to take into account thin layers when these are present in the geological setting.

Introduction

There are numerous examples of reservoirs with thin bed challenges in both continental and marine environments (ex. fluvial, deep water clastics, aeolian, and shallow marine deposition). In an effort to simplify fluid flow and seismic wave propagation, geological fine-scale models are often coarsened via the process of upscaling (for example Pickup and Hearn, 2002). However, previous research has shown that upscaling may be problematic for fluid flow calculations especially in the case of gas injection, which results in heterogeneous fluid saturation distribution (Sengupta, 2000; Castro and Caers, 2005; Kirstetter *et al*., 2006; Falahat, 2012). Moreover, if small-scale heterogeneity exists, capillary pressure becomes important (Stephen *et al*, 2002) and should be included in the fluid flow calculations. In the seismic domain, many researchers have recognized that below seismic resolution geology impacts the seismic response (for example Sengupta, 2000; Castro and Caers, 2005; Falivene *et al*., 2010). To our knowledge, seismic scale effects in 4D have not been fully studied, and the relationship between thin bedded geology, fluid flow, and seismic wave propagation remains unexplored. It is therefore important to model the signature of thin bedded geology on fluid flow and seismic behaviour in order to assess the correctness (or lack thereof) of coarse models.

The current paper focuses on the 4D seismic signature of gas saturated thin bedded geology for which key is to consistently capture the relevant scales as well as the correct properties, which define the geology, fluid flow and seismic wave propagation in the field. Based on the study of an outcrop analogue for a thin-bedded turbidite, we model the time lapse elastic properties in response to gas saturation changes, and the consequent seismic response for different levels of model scale, from fine scale geological grid to upscaled coarse flow simulation grids.

Methodology

Geological Modelling - as an outcrop analogue for turbidite reservoirs, we selected the well-studied AinsaII outcrop in Spain (Clark, 1995). We followed the geological model created by the Genetic Units Project at Heriot-Watt University, which is a 2D model (750m wide, 50m depth), of vertical/horizontal grid sizes 0.25m/0.3m, containing two dominant facies (sand, shale). To emulate reservoir field conditions, we assigned sand/shale rock properties (Table 1) after a West Africa turbidite field (Rangel, personal communication), along with representative values of residual oil saturations to water (S_{orw}=0.2) and gas (S_{org}=0.05), critical gas saturation (S_{gc}=0.05) and irreducible water saturations (S_{wirr}=0.2).

Table 1 *Static rock properties used to model AinsaII as a West Africa reservoir field.*

Facies	Porosity	NTG	K (GPa)	G (GPa)	ρ (kg/m^3)
Sand	0.30	0.90	19.00	10.30	2619
Shale	0.12	0.10	24.61	8.90	2725

Saturation and Pressure Scenarios - as an alternative to flow simulation, we considered four saturation scenarios, which were conditioned by fluid flow simulations of a West Africa turbidite field. The range of saturation and pressure conditions involved pressure depletion as well as gas injection processes: i) pre-production condition in the oil leg (S_w=S_{wirr}, S_o=1-S_{wirr}, S_g=0), ii) pressure depletion in the oil leg (S_w=S_{wirr}, S_o=1-S_{wirr}-S_{gc}, S_g=S_{gc}), iii) pressure depletion resulting in an oil/water contact movement (S_w=1-S_{orw}, S_o=S_{orw}, S_g=0), and iv) pressure depletion creating a secondary gas cap /or gas injection resulting in gas cap expansion (S_w=S_{wirr}, S_o=S_{org}, S_g=S_{gmax}=1-S_{org}-S_{wirr}). Pressure values is kept constant spatially for each scenario, and varied between 25 to 26 MPa. Scenario i) is treated for the base case for seismic, and ii)-iv) as monitors, which correspond to a time period of roughly 1 to 2 years.

Upscaling -to assess scale effects in 4D seismic, we upscaled the original geological grid (Δz=0.25m, Δx=0.3m) to successively coarser grids (with the largest grid being Δz=10m, Δx=30m). The objective of upscaling is to preserve the fluid volumes between coarse and fine scale models, which implies mass conservation. Hence, upscaling whilst preserving pore volumes, leads to the following equations (1a, b, c) for pore volume, porosity, and residual saturations:

$$PV_C = \sum_f PV_f \quad (1a), \qquad \phi_C = \frac{PV_C}{V_{total}} = \frac{\sum_f \phi_f * V_f}{V_{total}} \quad (1b), \qquad S_{i,C} = \frac{\sum_f PV_f * S_{i,f}}{PV_{total}} \quad (1c)$$

where C represents coarse grid, f represents fine grid, PV is pore volume, ϕ is porosity, and S_i is the saturation for residual oil to water/gas, or irreducible water, or critical gas saturation. Modelled porosity and saturation scenarios for water-dominated (scenario iii) and gas-dominated (scenario iv) conditions are shown in Figure 1.

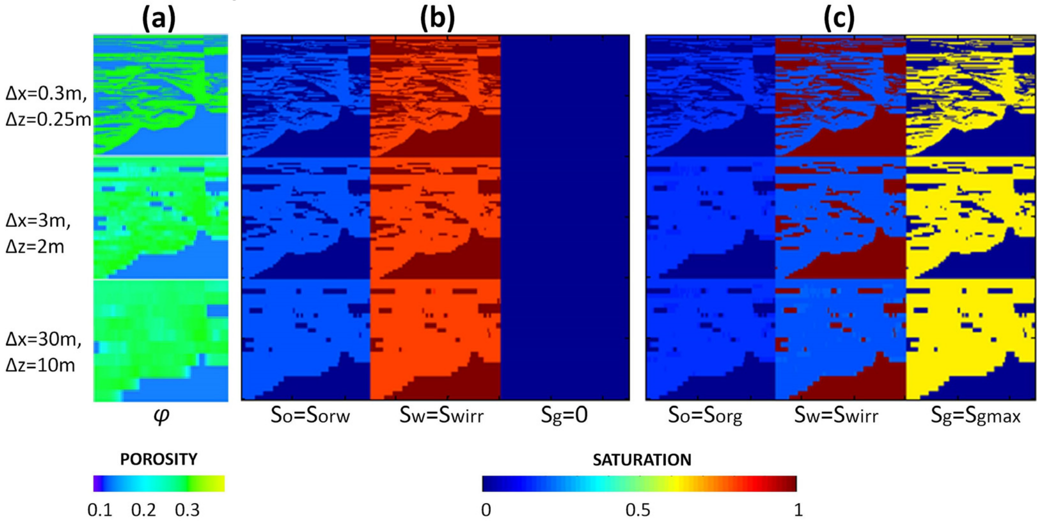

***Figure1** The effect of upscaling on porosity (a), showing fine scale (top), and coarser scales (middle and bottom). Saturation for fine scale and coarser models is also shown for the (b) water-dominated condition (Sw=1-Sorw, So=Sorw, Sg=0), and (c) gas-saturated condition (Sw=Swirr, So=Sorg, Sg=Sgmax=1-Sorg-Swirr)*

Seismic Modelling - it is well-known (for example O'Doherty and Anstey, 1971) that thin beds, if stacked through a thick sequence, result in non-negligible transmission loss, but also complex multiple reflections, which may interfere with the primary reflections. Hence, to ensure modelling of seismic interaction at thin scale models properly, one needs to account for transmission, multiples, as well as converted waves. For this purpose, the computed synthetics are based on the Kennett algorithm (Kennett, 1981), which involves the computation of all wave types.

Results and Discussion

Synthetic seismic data are computed for the four different saturation scenarios considered, and for the fine-scaled and coarser upscaled models. AVO effects are also considered by exploring three different stacks: 0-10°, 10-20°, and 20-25°. The modelled source is a 65 Hz Ricker wavelet, which captures a typical bandwidth from a West Africa field. To isolate the effect from multiples, we computed synthetics for primaries only, and also those including multiples. As shown in Figure 2, multiples constructively interfere and produce a brightening for the fine-scale model (an increase in 4D amplitude in the order of 30%), but have a less pronounced effect in the upscaled models (equal to less than 1% for the coarser model). This effect is due to the process of upscaling which practically smooths out the impedance contrasts between sandy/shaley layers; effectively the same volume of fluid going in the coarse and fine scale flow models, but occupies a very different space (blocks of intermediate porosity versus high porosity 'veins'). Hence, coarse scale models will contain not only a smaller number of interfaces (causing less multiples to be created), but also smoother impedance contrasts across boundaries. In terms of AVO, we found a weak increase of amplitude with angle (a 4D seismic amplitude increase in the order of 5% between near and far stacks); in addition, multiples appear to be consistently important for near/mid- and far- stacks, for the fine-scale model. To quantify AVO effects, we computed the NRMS (normalized root mean square) value from the 4D seismic data. As shown in Figure 3, for the coarse scale model, the multiples and converted waves have a negligible effect for all stacks. For the fine-scale model, the NRMS trend as a function of incidence angle is in the order of 6%, consistent with the AVO reflectivity trend, which also increases with incidence angle (by about 10%). Lastly, we analyzed the effect of the source frequency, by comparing two different source centre frequencies: a low frequency source (22 Hz) which would be more typical of a North Sea field, and a higher frequency source (65 Hz) which is more typical for a West Africa field. As shown in Figure 3, thin layers give rise to multiples, which can be detected even in the synthetics of the low frequency source.

Conclusions

Even though upscaling of the geological grid to a more computationally manageable flow simulation grid is common in research and the industry, the 4D seismic signature may be highly distorted. The key to understanding the effect of gas saturation interacting with thin bedded geology lies in capturing the correct scale and properties in all geological/fluid flow and seismic domains. Through synthetic seismic modelling of an outcrop analogue, we show that seismic wave phenomena, such as transmission, multiples and converted waves vastly contribute to the measured amplitudes. Hence, any forward/inverse modelling from the flow simulation to the seismic domains involved in quantitative 4D has to take into account thin layers when these are present in the geological setting.

Acknowledgements We thank the sponsors of the Edinburgh Time Lapse Project, Phase V, for their support (BG, BP, Chevron, CGG, ConocoPhillips, ENI, ExxonMobil, Hess, Ikon Science, Landmark, Maersk, Norsar, RSI, Nexen, Petoro, Petrobras, Shell, Statoil, Suncor, Taqa, TGS and Total). Thanks are extended to Schlumberger for providing the Petrel and Eclipse software. We would also like to thank Prof. Andy Gardiner for his helpful discussions on turbidite geology and providing the outcrop model.

References

Castro, SA, and Caers, J. [2005] Downscaling saturations for modeling 4D seismic data, Report of Stanford Center for Reservoir Forecasting. *Accessed June 2014 via: https://pangea.stanford.edu/departments/ere/dropbox/scrf/documents/reports/18/SCRF2005_Report18/SCRF2005_paperScarletCastro2.pdf*

Clark, J.D. [1995] Detailed Section Across the Ainsa II Channel, South-Central Pyrenees, Spain: in Pickering, K.T., Ricci Lucchi, F., Smith, R., Hiscott, R.N., and Kenyon, N.H. *An Atlas of Deep-water Systems*. Chapman and Hall, 139-144.

Falahat, R., Obidegwu, D., Shams, A., and MacBeth, C. [2014] The interpretation of amplitude changes in 4D seismic data arising from gas exsolution and dissolution. *Petroleum Geoscience,* **20**, 303-320.

Falivene, O., Arbues, P, Ledo, J., Benjumea, B., Munoz, J.A., Fernandez, O., and Marinez, S. [2010] Synthetic seismic models from outcrop-derived reservoir-scale three-dimensional facies models: The Eocene Ainsa turbidite system. *AAPG Bulletin*, **94**, 317-343.

Kennett, B.L.N. [1983] *Seismic wave propagation in stratified media*. Cambridge University Press.

Kirstetter, O., Corbett, P., Somerville, J., and MacBeth, C. [2006] Elasticity/saturation relationships using flow simulation from an outcrop analogue for 4D seismic modeling. *Petroleum Geoscience*, **12**, 205-219.

O'Doherty, R.F., and Anstey, N.A. [1971] Reflections on Amplitudes. *Geophysical Prospecting*, **19**, 430-458.

Pickup G.E. and Hern, C. [2002] The development of appropriate upscaling procedures. *Transport in Porous Media*, **46**, 119-138.

Sengupta, M. [2000] *Integrating rock physics and flow simulation to reduce uncertainties in seismic reservoir monitoring.* PhD Dissertation, Stanford University.

Stephen, K.D., Clark, J.D., and Pickup, G.E. [2002] Modeling and flow simulations of a North Sea turbidite reservoir: sensitivities and upscaling. *SPE 78292*.

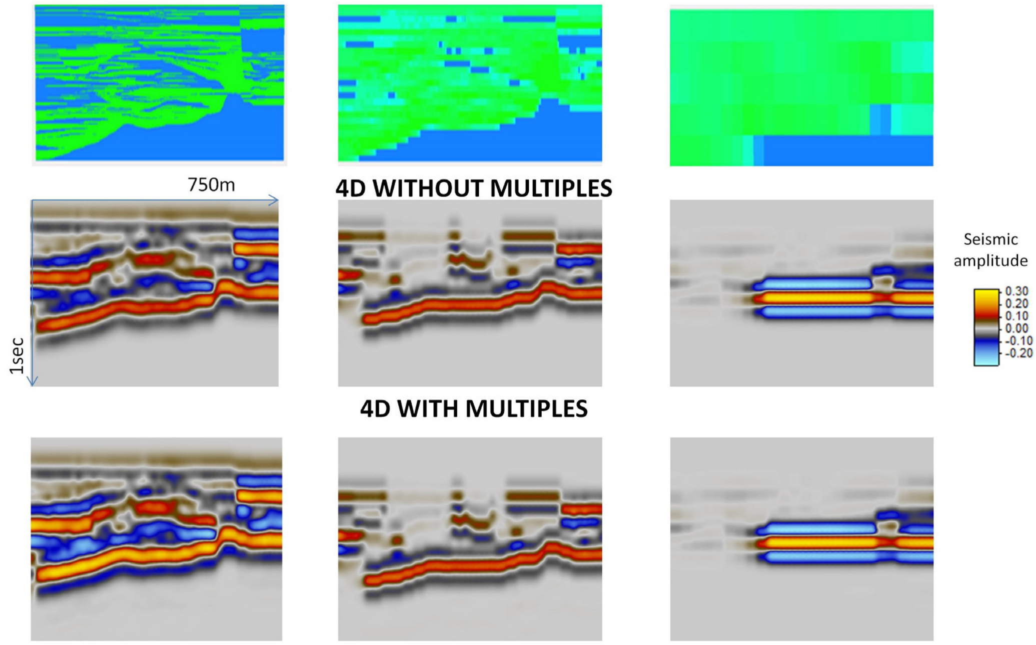

Figure 2 *Effect of scale and multiples. 4D difference (base: water saturated, monitor: gas saturated) for fine scale model (left), intermediate model (middle), and coarse scale model (left). All sections are for near-stack. The porosity models are shown in the top row for reference.*

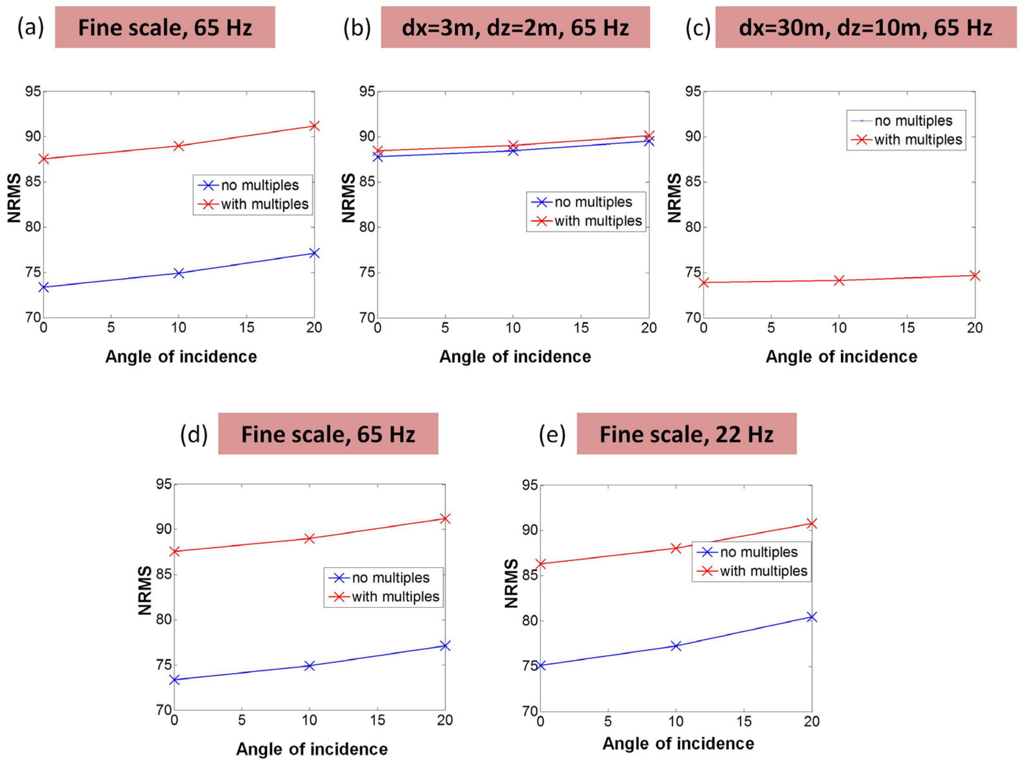

Figure 3 *NRMS values for the 4D seismic data (base: water-saturated, monitor: gas-saturated. The top three figures show the effect of scale in terms of the contribution of multiples, as a function of the angle of incidence. The bottom two figures show the effect of the source's centre frequency.*