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Quantification of Reservoir Pressure-sensitivity Using Multiple Monitor 4D Seismic Data

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SUMMARY

Key to quantitative interpretation of 4D seismic data for the separation of pressure and saturation effects is accurate knowledge of their individual contributions to the 4D seismic signatures. Currently, pressure sensitivity is calibrated using laboratory measurements on core plugs that have limited applicability to the in-situ field-scale reservoir response. A complementary technique for estimating pressure sensitivity is to compare seismic and pressure measurements. This is possible in selected areas around and away from wells where pressure variations contribute predominantly to the 4D signatures. Multiple monitor 4D seismic data are utilised to sample these areas as a function of field production time. The technique is applied to seismic amplitudes across a variety of producing North Sea clastic reservoirs. The results indicate that pressure sensitivity varies according to the geology of each reservoir. Also, estimates around some water injectors appear to show elevated sensitivity, suggesting the presence of induced fractures.

Introduction

The stress sensitivity of the reservoir rocks (due to fluid pore pressure change) though a mature subject, lacks proper in-situ calibration. Much of our current knowledge is based on laboratory experiments with core plug samples, where elastic moduli of the rock are measured under various isotropic or uniaxial applied loads. However, many studies have raised concern with these laboratory measurements and their suitability for replicating the in-situ reservoir response (Alvarez and MacBeth 2014). Alternative attempts have also been made to measure the stress sensitivity using other data. For example, Fürre et al. (2009) combined repeat formation tester and well log data to reveal weaker in-situ stress sensitivity than in the laboratory. Amini and MacBeth (2015) inferred the sensitivity by comparing observed 4D seismic data with synthetic data from a simulator to seismic study at areas around water injectors where pressure changes dominate. The purpose of this current study is to extend the latter approach by generalising the concept beyond just water injectors by including data acquired at different monitor times, and to apply the method to a wide range of offshore fields with different geological environments.

Method

Our method relies on the use of multiple repeated monitor surveys shot across a field undergoing production and recovery. We measure the magnitude of 4D seismic signals at different times and at specific locations in the reservoir where pressure changes are considered to be the over-riding influence, this is then cross-plotted against the estimated pressure changes. At these key locations, the hydrocarbon reservoir can experience a diversity of pressure changes, ΔP, over time and across the different monitor surveys (such as injection, depletion, re-pressurisation or relaxation). Sampling the seismic response over a sufficiently wide range of pressure changes enables us to evaluate the pressure sensitivity (Figure 1). The fields we have selected have up to five monitor surveys. For the method to work, there has to be significant pressure change between monitor surveys and good knowledge of the pressures at these reference locations. Estimated pressures are obtained from bottom-hole-pressure (BHP) for wells perforated in the reservoir, repeat-formation-tester (RFT) logs and depth-averaged maps of simulated pressures from a well history-matched reservoir model. These pressure data sources carry their own uncertainties, with the measured historical BHP or RFT pressure generally more reliable than simulated data (Beaumont et al. 1999). For the seismic data, our current work focuses around amplitudes sensitive to reservoir changes. Specifically, we work with top reservoir amplitude maps of post stack migrated data (full stack) computed using appropriate window parameters to suit each reservoir. Before proceeding, the seismic data are calibrated via 3D and 4D well ties (well production data co-located in space and time with the seismic response), and also calibrated for sim2seis studies (Amini 2014).

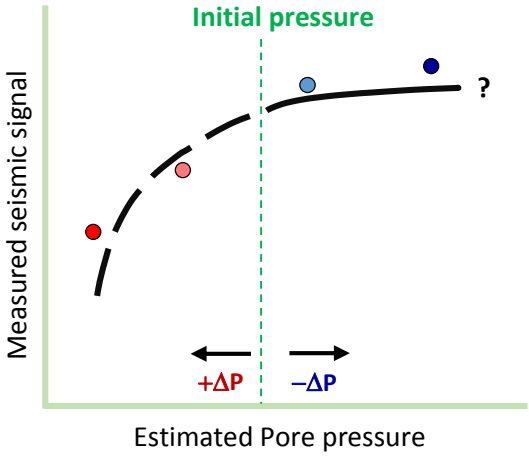

Figure 1 *Generalised stress-sensitivity curve (black). Areas in the reservoir may exhibit a range of pore pressures for sampling across monitor times.*

Although areas where pressure changes dominate are likely to be strongly field dependent, some generalisations are possible to guide our study: **(i)** ***Inside water-flooded areas or regions of undisturbed fluid saturations*** **-** areas water-flooded at a previous monitor time are likely to show pure pressure signals in subsequent monitor surveys. This result may however be biased by fractures existing around the borehole. We start by calibrating signals around water-flooded wells and expand outwards to larger water-flooded regions. Areas in the natural water or gas leg are useful as initial saturation levels are likely to remain fixed over time. **(ii)** ***Outside areas undergoing significant saturation changes*** **-** whilst theoretically small, pressure signals should still exist away from injectors and outside the influence of a growing water-flood front. Likewise, in areas away from producers undergoing depletion but no associated gas breakout in oil leg or negligible gas condensation effect in gas fields. These areas could be significant if the injection or depletion response is inside a compartment. One assumption is that other changes such as temperature, salinity or saturation changes are negligible, and this can be checked to some extent by modelling.

Application to field datasets

The method is applied to four North Sea clastic reservoirs with different characteristics. Pressure scenarios are identified by the polarity of the pressure change, reservoir location, and measurements at and away from wells. For measurements around wells, the 4D signals are taken within 200 m of the well perforation points. Measurements away from wells and in compartments are extracted by drawing polygons around the pressure signals on 4D maps. In Figure 2, we show pressure calibration using well pressure and injection data to interpret the 4D amplitude signatures for one scenario of a single water injector in an oil-leg compartment in field A. The analysis must be performed on a monitor by monitor basis per location as not all monitor surveys give clear pressure signals depending on well activity. Furthermore, complexities arise when calibrating pressure signals in other parts of field A because the signal variations predominantly relate to other effects across the reservoir. Below, we briefly describe each field and Table 1 details our results for their identified pressure scenarios.

- **Field A** is a tertiary deep water stacked turbidite reservoir composed of calcite cemented channel sands with average effective porosity 1 to 15%. The reservoir has black oil close to bubble point and production is by water injection to maintain pressure. Connectivity is a problem, and several compartments exists. Five monitor surveys (1999 to 2008) have been acquired with average non-repeatability noise 30 to 60%. Pressure effects are around water-flooded injectors, away from the water-flood front (outside wells) and in a compartment using the 2004, 2006 and 2008 surveys.

- **Field B** is a horst block of four segments divided into two separate compartments with good internal connectivity, composed of lower to middle Jurassic cemented fluvial sands with effective porosity 15 to 20%. Production of the oversaturated oil is by water injection and water-alternating-gas (WAG) injection. Four monitor surveys between 2001 (base) and 2006 have been acquired with non-repeatability 20 to 40%. Post 2001 re-pressurisation occurred and the pressure effects grew with time in the smaller compartment (a segment with a producer and water injector).

- **Field C** is a large fault-bounded dip closure with numerous fault segments but good connectivity composed of late Jurassic shallow marine sands. Reservoir sandstones are unconsolidated and homogenous with porosities 27 to 30%. Production of the oversaturated oil is by water injection and gas and WAG injection. Five monitor surveys (2001 to 2011) have been acquired with non-repeatability 20 to 30%. Oil had been produced by 2001 and subsequent surveys show mild pressure effects in the water leg (around injectors) and water-flooded oil leg (around producers).

- **Field D** is a highly stressed rotated fault block composed of deep water Jurassic stacked shoreface slightly consolidated sands with porosity 20 to 25%. The reservoir is a high-pressure-high-temperature (HPHT) gas condensate above dew point. Four seismic monitor surveys in 2001 (base), 2002, 2004 and 2013 with non-repeatability 5 to 15%. Production is by pressure depletion.

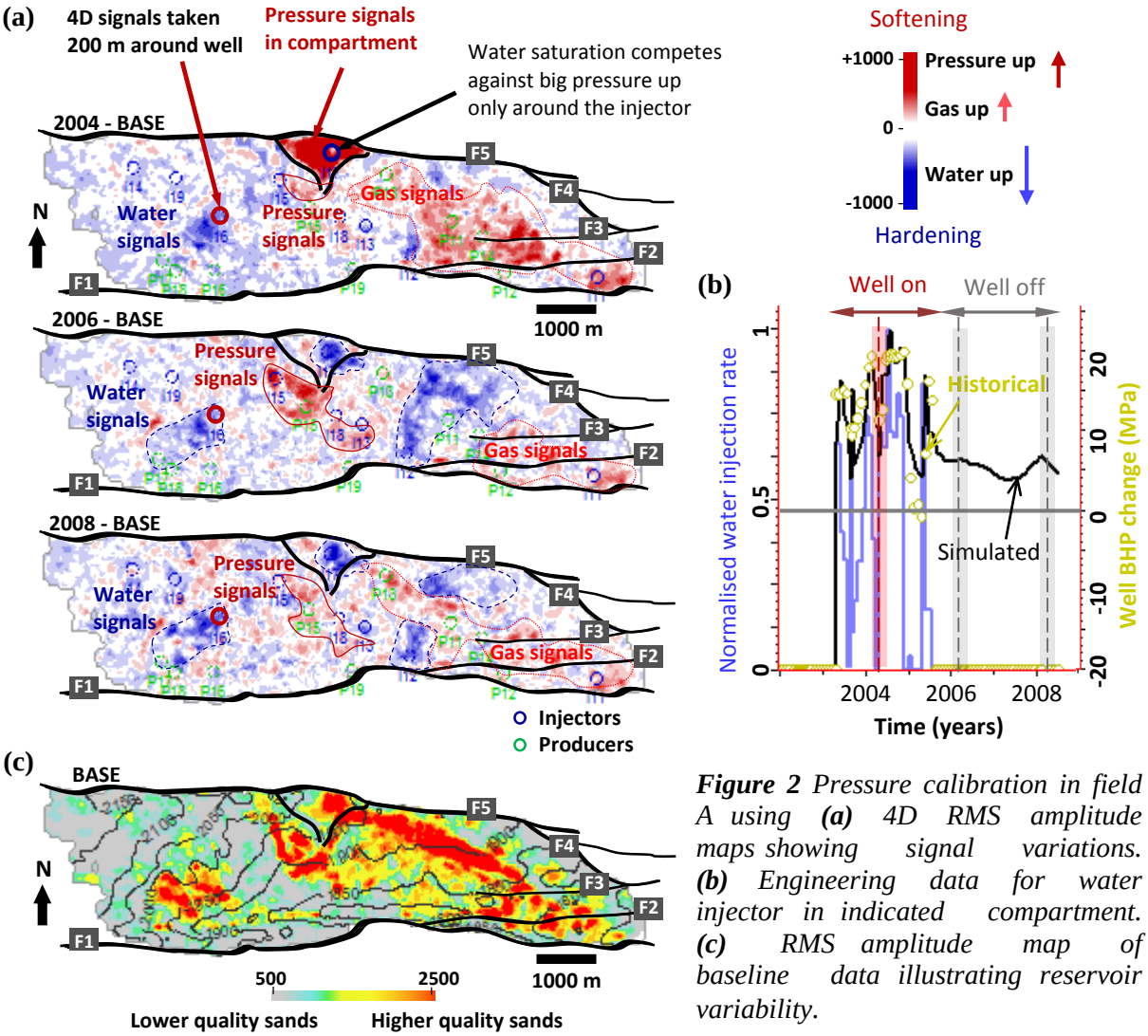

Figure 2 *Pressure calibration in field A using* ***(a)*** *4D RMS amplitude maps showing signal variations.* ***(b)*** *Engineering data for water injector in indicated compartment.* ***(c)*** *RMS amplitude map of baseline data illustrating reservoir variability.*

Results and discussion

The results are shown in Table 1. We find pressure sensitivity varies quite considerably across the fields. The normally pressured unconsolidated sands of Field C are the most pressure sensitive while the slightly consolidated sands of the HPHT Field D are the least sensitive. Pressure sensitivity is certainly a seismic attribute dependent quantity, and we believe that the results may depend on the attribute measured, time gate, and also if time shifts are used instead. Interestingly, we observe an increased sensitivity around some water injectors in Field A, which may be due to induced fractures. The pressure sensitivity for amplitudes ranges from 4.5%/MPa to a much higher 17% for these fractured areas. Pressure sensitivity is 1.0%/MPa for Field B, 8.0%/MPa for field C and 0.3%/MPa for Field D. In comparison, laboratory-derived pressure sensitivity using bulk moduli (MacBeth, 2004) recorded a maximum of 10%/MPa for high porosity unconsolidated sands and 1%/MPa for the lower-porosity, cemented, and more-consolidated sands. All core sample measurements were assumed to be over-estimates. Whilst our measurements are consistent, limitations are: non-repeatability noise, assumption of the negligible influence of other phenomena in the areas studied and unreliability of available pressure measurements. In areas where there are no wells, depth-averaged maps of reservoir model simulated pressures are used, which may be in error. Likewise, analysis on Fields A, B and C used simulated well BHP and these are less accurate than historical pressures. Errors in simulated pressures are likely to be up to 25% - based on the misfit between their historical and simulated field production rates for gas, oil and water.

Conclusions

A technique for quantifying pressure sensitivity using multiple monitor seismic amplitude data has been successfully applied to four offshore clastic reservoirs. Our seismic-based method is transferable to other field types e.g. carbonates and could fill the gaps in rock-physics derived or laboratory-based measurements of pressure sensitivity. The method can also be extended for sensitivity measurements of other time-lapse effects such as saturations, temperatures etc. In doing so, we can better tackle the separation of pressure versus saturation for improved reservoir management. Finally, we note the implications of using post-stack data for pressure related studies (Omofoma and MacBeth, 2015) but justify our practical approach to be effective in areas with sufficiently large seismic signals.

Field	Pressure scenarios	No. of wells / monitors used	ΔP (MPa)		%ΔA	
			Mean	**std**	**Mean**	**std**
A	Compartment	1 injector / 1	18.0	0.35	122	71.6
	Water-flooded	4 injectors / 2	3.31*	1.81*	14.9	14.9
	Outside wells	None / 3	4.00	1.50	30.7	30.6
	Fractured	2 injectors / 2	-2.12*	0.84*	-36.4	8.80
B	Compartment	1 injector / 2	25.2*	5.40*	26.0	21.0
C	Water-flooded	7 producers / 4	-4.66*	3.21*	-21.0	5.10
	Water leg	5 injectors / 4	6.42*	3.80*	21.3	11.9
D	Gas leg	6 producers / 2	-53.3	4.40	-15.0	9.90

Table 1 *Mean and standard deviation (std) of amplitude-pressure sensitivity in four clastic reservoirs for each pressure scenario identified, number of wells and a number of monitor surveys. Pressure is well BHP (historical or simulated), or a depth-average prediction from the history-matched simulation model. * denotes simulated pressures.*

Acknowledgments

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