A fast-track simulator to seismic proxy for quantitative 4D seismic analysis

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Summary

We propose a stable and accurate proxy for generating maps of 4D seismic attributes using only the original baseline seismic data and fluid-flow simulation predictions. The approach provides a fast track procedure for generating 4D seismic data from the simulator. It has particular use in quantitative 4D seismic analysis, and specifically for incorporating time-lapse seismic data into the history-matching loop where many seismic modeling iterations are required. The method circumvents the petro-elastic model with its associated uncertainties and also the need to choose a seismic full-wave or convolutional modeling solution. Despite the relative simplicity of the proxy, it is found not to bias the choice of optimal solution for the history match. Application to synthetic datasets based on a two North Sea fields indicates that the proxy can remain accurate to within a mean error of 5%.

Introduction

In reservoir management, integration of the dynamic well data into the reservoir model is achieved via history matching, the process of calibrating the model to make it reproduce the historical well behavior. The more static and dynamic data the simulation model is consistent with, the more reliable will be the model forecasts of future performance. An increasingly popular type of dynamic data that can be used for history matching is time-lapse (4D) seismic data (for example: Gosselin et al. 2001, Stephen and MacBeth 2006, Roggero et al. 2007). 4D seismic data has a better areal coverage of the reservoir than 1D well data, and is thus potentially useful as a further constraint. However, unlike well data, where the simulation model predictions can be compared with the production activity, time-lapse seismic data are not directly comparable with the output of fluid flow simulation.

From a practical perspective, simulator to seismic modeling is one of the most difficult and potentially erroneous tasks facing a reservoir engineer engaged in a seismic history matching (SHM) project. It requires selection and calibration of a petro-elastic model (PEM) (Alvarez and MacBeth 2014), building of a seismic geo-model of impedances, followed by seismic wave propagation modeling (Figure 1(a)). Finally, the key geological events for the reservoir must be identified and picked on the synthetic data and the requisite attributes evaluated. Unfortunately, in this process there is no straightforward way of avoiding the petro-elastic modeling or seismic modeling route. Indeed, if the comparison is performed by firstly inverting the seismic to pressure and saturation changes, then the PEM is still involved (Landrø 2001, MacBeth et al. 2006). Furthermore, if the intermediate domain of seismic impedances is used, the PEM must convert the simulator output to impedances (Stephen and MacBeth 2006). For this latter choice, although seismic modeling is avoided, one must still convert the seismic into an impedance volume using a suitable rock physics model. Thus, the simulator to seismic modeling step still affords a considerable bottleneck to making full use of seismic data in the final quantitative update of a simulation model. It significantly increases the difficulty of undertaking an SHM that requires fast model runs and the computation of seismic data at each iteration. The seismic modeling steps are both time-consuming, carry considerable uncertainty due mainly to the stress sensitivity component (MacBeth 2004; Furre et al. 2008), and require extensive calibration which is non-trivial (Amini 2014).

In an attempt to circumvent the difficulties outlined above, this current work implements a proxy (or response surface) for the PEM plus seismic modeling steps of the calculation (Figure 1(b)). This approach speeds up the workflow considerably and allows a reservoir engineer with no prior knowledge of seismic data or modeling to gain immediate access to 4D seismic data as a matching tool.

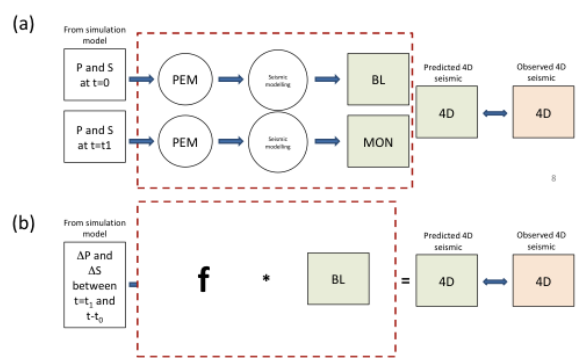

Figure 1 (a) Schematic illustrating the workflow required for modeling 4D seismic data for the purposes of comparing with the observed data. The processes in the red box are those for which a proxy is to be sought. (b) The proxy solution from this work, where the function *f* is at most a quadratic in terms of pressure and saturation change.

Development of the proxy

The objective of this work is to provide a quick and robust prediction of the seismic data from the pressure, water and gas saturation changes output from fluid-flow simulation. To do this we limit ourselves to only mapped seismic attributes, where the attribute has been evaluated with respect to a clear, stable and interpretable seismic horizon such as the top of the producing reservoir clearly identified in the seismic volume. The use of mapped seismic quantities is justifiable as many of the reservoirs we have interpreted are generally thinner than a fraction of a seismic wavelength, and the seismic response provides an adequate average of the fluid saturation and pressure for the entire producing depth interval. Maps for time-lapse seismic analysis are created by differencing the monitor and the baseline survey maps. The challenge is to calculate the time-lapse seismic map from depth-averaged pressure and saturation changes obtained via fluid-flow simulation.

Figure 2 shows observed maps of the root mean square amplitude of the top reservoir event for a North Sea clastic field (Obidegwu et al. 2015). Maps for the baseline (pre-production) survey and several subsequent monitor surveys are displayed. For reference purposes, Figure 3 gives an identical sequence of maps, but all are now derived from full synthetic seismic computation from a known simulation model using a well-log calibrated petroelastic model (see Amini 2014 for details). Inspection of the sequence for both observed and synthetic data indicates that both baseline and monitor images look visually similar. This is what we might expect, as the baseline response reflects the geological imprint of the reservoir's depositional architecture together with the initial fluid saturations and pressure. The monitors represent the same geology but with the fluid component and pressure perturbed due to well production and recovery. Key to our understanding is that these saturation and pressure signals only modify the seismic amplitudes in the regions bounded by reservoir, and thus the regions defined by the initial amplitude distribution. Of course, there are examples of saturation or pressure related time-lapse signals present outside the initially defined reservoir boundaries (Kloostermann et al. 2003), but these are generally not common and would be known prior to our analysis. A reservoir-related amplitude on the baseline seismic data will thus either brighten or dim in response to fluid saturation or pressure changes, but non-reservoir related amplitudes do not – assuming no geomechanical effects. A strong reservoir amplitude, consistent with a thick high porosity and low net-to-gross sand, also gives a strong time-lapse seismic response in response to production activities. The reverse is true for a lower quality reservoir sand. Obviously there is a limit this process - if the acquisition survey for the monitor seismic data does not adequately match the pre-production baseline survey, then non-repeatability noise will dominate.

To capture the above remarks, let $A_0(x,y)$ represent the seismic response at the pre-production baseline time and ΔR the effect of subsequent fluid saturation and pressure changes in the reservoir. Analysis of modeling and data suggests that the time-lapse seismic map $\Delta A(x,y)$ can be constructed as the product

$$\Delta A(x,y) = f(\Delta R, G).A_0(x,y) \tag{1}$$

where f is a function of the production-related changes and the geology, G, which depends on the petroelastic and seismic modeling. By involving the observed pre-production baseline survey in the time-lapse seismic calculation, we account for known (or unknown) lateral variations of the static reservoir properties such as thickness, porosity and net-to-gross, as well as destructive and constructive wavelet interference effects such as tuning in the 3D dataset. An additional benefit is that ΔA is already calculated in the attribute 'currency' of the seismic data. The form of the proxy function f can be considered from analogy with successful proxy (or response surface) modeling elsewhere (He et al. 2015). In our case, as we are dealing with relatively small changes, one obvious form for $f(\Delta R, G)$ can be obtained by a second order Taylor's series (see also MacBeth et al. 2006)

$$\Delta A = (a_1\Delta P + a_2\Delta S_w + a_3\Delta S_g + a_4\Delta P^2 + a_5\Delta S_w^2 + a_6\Delta S_g + a_7\Delta P\Delta S_w + a_8\Delta P\Delta S_g + a_9\Delta S_w\Delta S_g).A_0. \tag{2}$$

The relationship in (2) amplifies or diminishes the baseline seismic response according to the depth-averaged pressure ΔP and saturation (ΔS_w, ΔS_g) changes obtained from simulator predictions (they already obey material balance, and so too will the 4D seismic data), to yield the mapped time-lapse response ΔA. The coefficients a_i: i=1,9 are derivatives of the seismic attribute with respect to the individual pressure and saturation changes. The coefficients are functions of the reservoir geology, rock properties and fluid properties. As the bulk of the variability is supplied by the baseline amplitude the weighting coefficients a_i can be assumed fixed across the reservoir.

This approach is valid in practice provided the seismic survey configurations are reasonably repeatable, and that additional wave interferences are not induced by the time-lapse differencing procedure (i.e. 4D tuning). For the latter, it is helpful that differences of attribute maps are utilized rather than maps of the raw difference volume as these are more robust to time-shift effects, particularly for attributes calculated within a window such as the RMS (root mean

square) or sum of negative amplitudes. An additional benefit of the generalized framework in (2) is that any particular seismic attribute such as impedance, RMS amplitude, instantaneous frequency, time-shift etc., will work in practice for ΔA. Finally, although the 'proxy' relationship in (2) is partially empirical in origin, and thus seems to be less physically justifiable than a full-fledged petro-elastic model and full-wave propagation, the utility of the dynamic part of this equation has been established in past inversion studies (for example, Alvarez and MacBeth 2014). It should be noted that in the literature some debate has arisen as to whether only the linear terms in (2) should be preserved (Falahat et al. 2013). The quadratic form does appear necessary in some cases if gas is present, with perhaps the necessity of an exponential behavior in some reservoirs (Floricich et al. 2006). At a practical level, the linear version of this proxy is found to be useful for the purposes of directly inverting to pressure and saturation changes (Landrø 2001, MacBeth et al., 2006, Falahat et al., 2013). The accuracy and robustness of these proxy forms for modeling and history matching purposes will be tested in the next section.

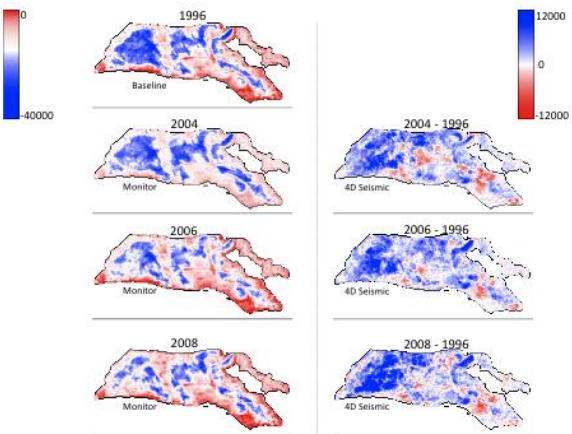

Figure 2 Comparison between the observed mapped seismic amplitudes for multiple 3D seismic surveys (left); and the corresponding mapped 4D seismic responses (right). The 1996 survey is the pre-production baseline, and all others are the monitors. The seismic attribute evaluated is the normalised RMS amplitude in a time gate of +/- 15ms either side of the picked horizon for the top of the producing reservoir interval for this North Sea field A.

Application to seismic history matching

The key to using (2) effectively in modeling as part of history matching is the rapid evaluation of the a_i coefficients without recourse to the time-consuming

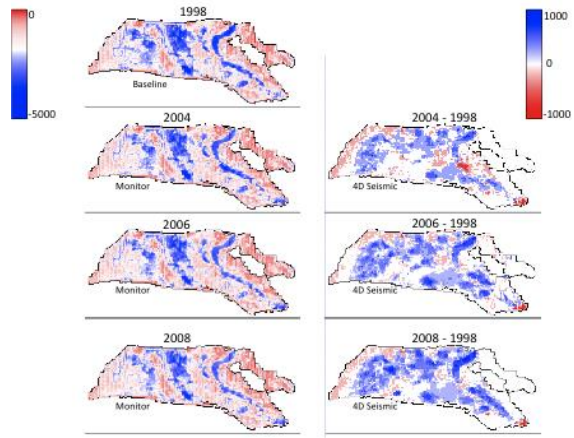

Figure 3 As in Figure 2, but for the synthetic data calculated using the full simulator to seismic modeling of Amini (2014).

calibration and modeling steps that we are trying to avoid. For any given simulation model run (and thus output pressures and saturations), the coefficients are determined by matching the righthandside of (2) to the observed time-lapse seismic data on the lefthandside. As there are only, at maximum, nine coefficients for the proxy and typically thousands of data points, this matching procedure is over-determined and can be achieved by multiple linear regression. An important feature of the matching algorithm, to ensure robustness and accuracy, is the introduction of physical constraints or inequality rules to the coefficients. This is necessary, as the relative magnitudes of the individual terms do behave according to predictable physical laws. For example, if impedance is the measured attribute, then a reservoir pressure decrease ($\Delta P < 0$) leads to a reservoir hardening or increase in ΔA. The coefficient a_1 must therefore be negative for the solution to remain physical. Similar scenarios also arise with the other coefficients, giving $a_1 < 0$, $a_2 > 0$ and $a_3 < 0$. Figure 4 shows the result of this procedure for the multiple-monitor synthetic data in Figure 3 from a North Sea field. The overall pattern of the mapped response is captured well, and the proxy is observed to fit to within a mean error of a few percent. Variations between the linear and the quadratic application are seen to be slight: 3.2% error versus 4.5% respectively. The coefficients for ΔP, ΔS_w and ΔS_g do not vary significantly when moving from the linear to quadratic form of the proxy (a_1=-0.6MPa^{-1}, a_2=101.5, a_3=-230.6) -> (a_1=-0.5MPa^{-1}, a_2=124.6, a_3=-208.0), and the cross-terms are reasonably small (a_4, a_5, a_6 < max(a_1,a_2,a_3)), suggesting that in this reservoir and for these fluid mechanisms a linear form may be appropriate.

For seismic history matching the most important question is whether the multi-linear regression could compensate for a

bad model choice with equally bad predictions, and can influence the choice of the optimum and thus bias the selection of the best models. To test the impact of our approach on the ability of the SHM procedure in finding the correct optimal solution, synthetic tests are performed on reservoir models from two different North Sea field datasets A and B. The flow in Field A is governed by stratigraphy and for Field B it is governed by structure. In both tests, a full simulator to seismic modeling (sim2seis) has been performed with an extensively calibrated petroelastic model as a reference. A proxy model is created that matches the chosen reservoir model and its predictions to the reference case seismic data. Next, an ensemble of model scenarios are generated by stochastic variation of the controlling parameters (fault or geobody transmissibility multipliers and vertical permeability). For each model in the ensemble, the L2 norm objective function is determined for the difference between the reference 4D seismic response and the proxy response, and also between the reference case and the full simulator to seismic modeling. The results for thirty additional realizations for Field A and B are shown in Figure 5. Two tests are performed: in the first, the original a_i coefficients are fixed after one iteration; in the second the coefficients are re-evaluated after every iteration. Importantly, the behavior in the solution space for the objective function appears to well defined by the proxy, both in fixed and adaptive mode, and in good agreement with the full seismic modeling.

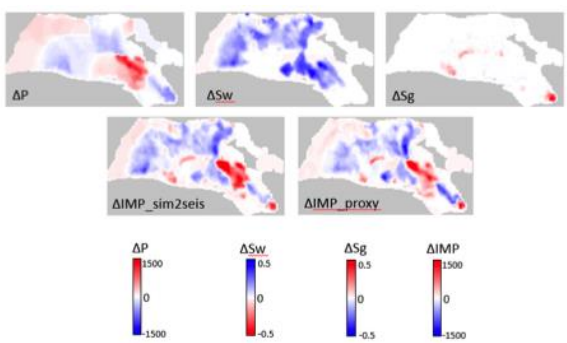

Figure 4 Field A comparison of pressure and saturation change output from the simulator with changes of impedance calculated with the full calibrated petroelastic model and the proposed proxy.

Discussion and conclusions

We have developed a fast-track seismic modeling procedure that helps to simplify seismic history matching and avoids the need for a petro-elastic model or full seismic modeling. The procedure relies on a data-driven relationship between the 4D seismic data and the reservoir dynamic properties. The procedure has been tested in a full seismic history matching workflow for two North Sea

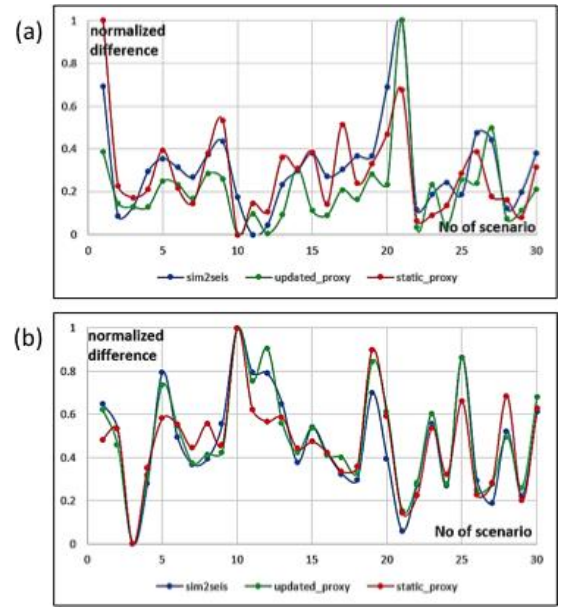

Figure 5 Misfits between predicted sim2seis solutions for thirty realizations of the simulation model and a pre-selected reference model. Blue line – full sim2seis calculation; Green line – adaptive proxy result; Red line – fixed proxy result. Results are for: (a) Field A; and (b) Field B.

fields and found to work well. The optimal SHM solution can still be found using the proxy, and solution space appears to have a similar character to that defined by full modeling. Whilst a perfect fit is not of course completely possible with a proxy, as the relationship between the depth-averaged pressure and saturation changes and the seismic data is in reality quite complex, it does appear that by working with mapped seismic attributes the response simplifies to the level where a good practical comparison is possible. The approximate result appears good enough to run a comprehensive seismic history matching, without recourse to the petroelastic model or seismic modeling tools that may not be readily available by an asset team engineer.

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EDITED REFERENCES

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