Time-shift inversion for dynamic reservoir characterization in the Elgin field

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Summary

A method is presented which numerically inverts the static field problem in a multilayered media, relating overburden strain directly to reservoir depletion. The present technique makes it possible to calculate the reservoir's stress state, strain and pressure changes from measured overburden strain via a least-squares inversion and linear filter theory, provided the overburden stays in the linear elastic regime. It requires however, a subsurface model and a geomechanical simulation in order to generate a set of transfer functions. The method is demonstrated using the HP/HT Elgin field.

Introduction

Until recently, dynamic reservoir characterization had only time-lapse well data to rely on, thus leaving a large gap of uncertainty between wells. Nevertheless, the advent of time-lapse seismic meant that this gap could be bridged, providing measurements of the changes taking place in the subsurface. In its origins, time-lapse seismic was conceived as a tool to image intra-reservoir fluid movements via the dependency of reflection amplitudes on impedance affected by fluid saturation in the porous reservoir rocks. However, changes in overburden velocity caused by changes of the effective stress in the reservoir are also non negligible. Furthermore, the subsurface reflectors may undergo deformations and displacements where compaction and subsidence are involved. As a consequence, analysis of amplitude changes is not straight forward, since in most cases, seismic events have been shifted by a non negligible time difference or time-shift.

There are many publications on the best way to calculate time-shifts and their applications (Hale, 2007; Hatchell and Bourne, 2006; Grandi et al, 2009). However, with few exceptions, time-shift analyses are confined to the reservoir and reduced to qualitative interpretations. Additionally, it is not uncommon for time-shifts inside the reservoir to be of poor quality, or for the whole area to be obscured. Meanwhile, the clear overburden time-shifts, are rarely used for reservoir characterization.

This study presents a method by which overburden strains, through their dependence on reservoir effective stress, can be inverted for reservoir compaction. This is accomplished on a case by case basis, i.e. for a specific subsurface configuration, where the static field problem is solved numerically. The solution comes in the form of Wiener-type estimated linear filters that are obtained using a subsurface model and preliminary geomechanical simulations in order to generate the transfer functions. The reservoir volumetric strain is obtained directly from the time-shifts by deconvolution with the filter, requiring only that the overburden can be regarded as a conjunction of linear elastic materials.

The study at hand uses measured time-strains from the Elgin field to calculate mean stress, porosity changes and pressure changes, and compares them with the values obtained from reservoir and geomechanical simulations.

Field description

The Elgin Field, discovered in 1991, is located 240 km east of Aberdeen in the South Central Graben Area, in the UK sector of the North Sea. The field lies in a complex geological structure almost six kilometers below the seabed. Three main reservoir units are identified, from top to base: Fulmar C sands, of moderate reservoir quality; Fulmar B sands with the best reservoir properties are the main contributor to production; and Fulmar A sands generally of poor quality. The overall Fulmar sand pay thickness is about 170 m with an average porosity of about 19 %. The good reservoir quality is due to the significant amount of porosity preserved by the extreme reservoir conditions; pressure of approximately 16,000 psi (110 MPa) and favorable diagenetic processes. These HP/HT conditions meant that production could not commence until 2001, when the many technological challenges were addressed.

The 1996 baseline survey covered an area of 290 km2. The acquisition parameters of the monitor survey, shot in 2005, were kept as close as possible to the baseline. The two surveys went through identical parallel processing sequences. Time and depth processing were carried out using the same velocity field, phase, time and amplitude corrections derived from the baseline and applied to both surveys.

A poroelastic multilayer solution

The problem posed by a static field propagating in multilayered media is common to many physical systems. On the subject of poroelasticity, various authors have studied and derived analytical solutions for elastic deformations in a halfspace, mainly by either of two methods: the nucleus of strain concept, Mindlin and Cheng

(1950) or by the activation of shear and tensile faults, Okada (1985). However, such analytical solutions are based on the assumption that 1) the Earth's crust is a semi-infinite ideal elastic body, and 2) deformations are caused by a hydrostatic pressure change in a spherical or point-source.

A natural choice to overcome these oversimplifications in search of a general solution might be to extend the closed solutions of elastodynamics to the limit of zero frequency. However, this leads to undesired numerical instabilities (Kuvshinov, 2007). For this reason, propagation of static fields in layered structures are analyzed numerically mainly by Finite Elements, Boundary Element, Finite Differences and the image source technique. All these methods however, are designed for forward modeling, e.g. to calculate subsurface displacements due to reservoir fluid extraction.

Successful inversion schemes have been so far confined to the simplest of Green's functions; i.e. a Geertsma (1966) type solution following Segall's (1992) approach. Under this methodology Du and Olson (2001), developed a forward/inverse model relating surface subsidence and reservoir pressure change, and validated it using some synthetic examples. Hodgson et al. (2007), extended this to invert measured subsurface displacements using time-lapse seismic from the Genesis Field in the Gulf of Mexico. Although encouraging, the results put in evidence the need for a more complete solution, to account for structure and especially different mechanical material contrasts.

Inversion by means of a transfer function

It is customary to write discrete linear inverse problems as a system of equations

$$\mathbf{G}(\mathbf{m}) \rightarrow \mathbf{Gm} = \mathbf{d}. \tag{1}$$

where **m** represents the set of physical parameters that characterize the model, **d** is a set of observed data and **G** is the function/s that relates **m** and **d**.

However, instead of solving the *inverse problem*, e.g. finding the system parameters **m** given **d** and the Green's function **G**; there is another case, that of the *system identification problem*, or determining **G** given samples of **m** and **d**. Such a system can be described by the convolution

$$\mathbf{d} = \mathbf{G} * \mathbf{m}, \tag{2}$$

where the aim is to find the set of equations **G**, to yield the smallest misfit. Note, that in equation (2) **G** operates as a linear-filter, thus from here onwards it will be identified as **f**, to avoid confusion with the conventional Green's function. As a consequence, applying least squares, one reformulates the objective function to minimize with respect to **f**

$$F(\mathbf{f}) = \left\| \mathbf{f} * \mathbf{m} - \mathbf{d} \right\|_2^2 \tag{3}$$

Solving numerically for **f**, one obtains the desired *optimum filter* or *Wiener filter* (Wiener, 1964). Having calculated **f**, or the transfer function in Laplace space, amounts to having found the coefficients that expand **d** as a set of differential equations with respect to the variable **m** (Arfken and Weber, 2001).

Knowing the Wiener filter of a system is of little practical use if the inverse filter cannot be calculated; that is the filter $\mathbf{f}^{-1}$, which has the property

$$\mathbf{m} = \mathbf{f}^{-1} * \mathbf{d}, \tag{4}$$

in a process known as Wiener deconvolution (Gonzalez and Wintz 1983). It is in this inverse mode that the Wiener filter has been applied in this study; to extract by deconvolution the reservoir's strain from measured overburden time-shifts.

Computation of the transfer functions

As time-shifts are a direct measure of subsurface displacements induced by reservoir activity (Hatchell and Bourne 2005), it will be of great use to know the displacement field induced by point-like sources; e.g. the Green's function that will make a solution of the inverse problem possible. However, despite the fact that no analytical or semi analytical solution exists for the complex non-homogeneous scenario; it is possible to cast the problem as a system identification problem, and calculate the transfer function/Green's function from the measured data as above. To compute the transfer function **f**, one needs to solve the set of equations (3), which requires knowledge of both **m** and **d**.

Given the difficulty of a reservoir-scale controlled environment to measure the sub surface's impulse response induced by a pulse-like reservoir pressure change, a coupled geomechanics and fluid flow simulator has been used. Though, the possibility of obtaining the Green's function directly from the data remains open.

Figure 1 describes schematically the process through which a system's transfer function can be approximated and used:

1. Selecting the appropriate pulse-impulse-response set. In other words selecting a confined and isolated production/injection area, with a spatial distribution as close to a pulse as possible, and its associated overburden displacement.
2. Once the input pulse and the system's impulse response have been selected, the Green's function or Wiener filter can be calculated by solving the set of normal equations (3).
3. Having calculated the Wiener filter **f**, it can be used either in forward mode by convolving the filter with known or simulated reservoir data, or in inverse mode, where measured overburden strains are deconvolved to invert for the reservoir data.

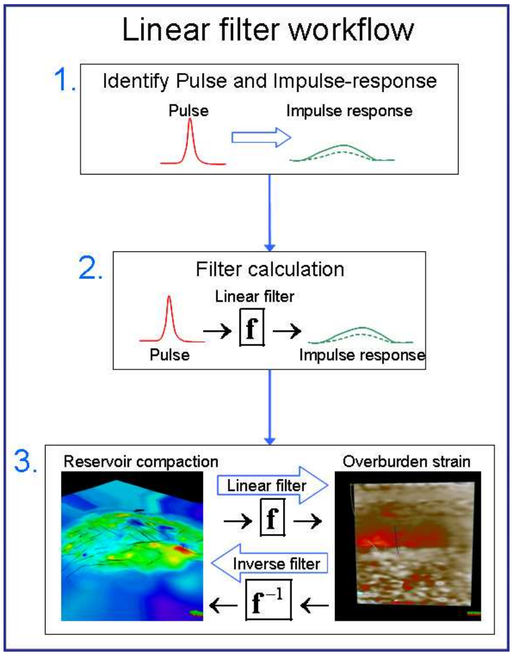

Figure 1: Workflow chart explaining the calculation and use of linear filters in time-lapse seismic data.

This ability to go easily back and forth proves the perfect tool to close the loop between seismic and the simulator.

Applications to the Elgin field

At the time the monitor survey was acquired (2005), four years after production started simultaneously in all wells, the pressure drop has spread through the reservoir area. Thus, it is not possible to identify from the data, any pulse-impulse-response pair in order to calculate the system's Wiener filter as described above. For this reason, a geomechanical model (VISAGE coupled to ECLIPSE) was used.

To this end, synthetic sources were placed in locations with minimal lateral inhomogeneities, e.g. porosity and permeability, in order to ensure a smooth pulse and correspondingly a well behaved impulse response. The synthetic sources or pulses are pressure changes that consist of a 1 MPa peak that decays to zero in the next 5 neighboring cells. This distribution is then fed into the geomechanics simulator to obtain the associated OB displacements or impulse-response.

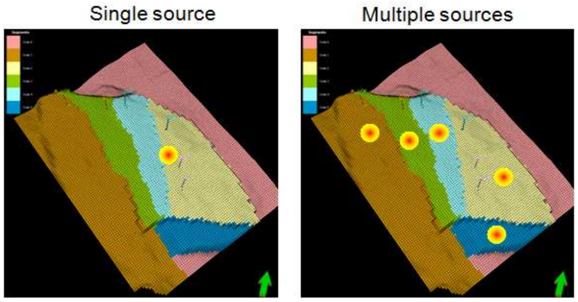

Figure 2: Source locations for the single source study (left) and multiple source study (right). The different colors correspond to the different reservoir compartments on Fulmar C (top reservoir).

In part to test the robustness of the method, but mainly to investigate the dependency on the source location, two separate studies were carried out: a single source placed in roughly the middle of the reservoir and five sources, each placed roughly in the middle of each of the reservoir compartments (Figure 2). Note that each "source location" actually contains several vertically stacked sources; one for each of the reservoir flow units (in this case three). This allows discrimination of the contributions from all reservoir layers, and thus the ability to invert them separately.

However, the very nature of linear filters requires that the system in question has to be linear and time invariant. In other words, that the linear elastic constants remain constant through time. For this reason, even though the "prize" will be to invert for pressure changes in the reservoir from measured time-shifts, this will require that the reservoir behaves as a linear elastic solid. It could be hypothesized that tight reservoirs should not deviate much from linear elasticity, nevertheless chalk or HP/HT reservoirs like Elgin certainly do. Thus, it is preferable to invert for reservoir volumetric strain, instead of pressure, since even if the reservoir's deformation is not elastic, that of the overburden nearly always is due to the smaller strains and provided no faults or weaknesses (Vasco and Ferretti, 2005). Hence, the relation $\Delta P \rightarrow \varepsilon_{zz}$ is not linear for reservoirs that deform plastically, but $\varepsilon_{vol} \rightarrow \varepsilon_{zz}$ will always be linear regardless of the reservoir's behavior.

The vertical strains ε_{zz} are calculated using an R-factor of 50 for the overburden, 8 for the caprock and 2 for the reservoir and underburden (De Gennaro *et al.* 2008). In order to increase the signal to noise ratio, the strains were averaged between formations.

Results and conclusions

Having calculated the set of linear filters for the three reservoir units, as described above for the single source and multiple source scenarios, the measured vertical strains are deconvolved with the respective inverse filters. Time-strains from the Hod formation were selected, given the apparent higher signal to noise ratio when compared with the other formations. The results are compared with simulated volumetric strain using VISAGE coupled to a history-matched ECLIPSE-300 reservoir model corresponding to the time lapse period.

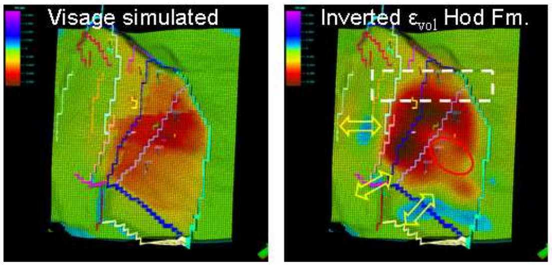

Figure 3: Volumetric strain for the Fulmar B sand (mid reservoir), for the single source location study. The left figure shows the simulated results, compared with inversions from average time-strains at the Hod Fm. (right).

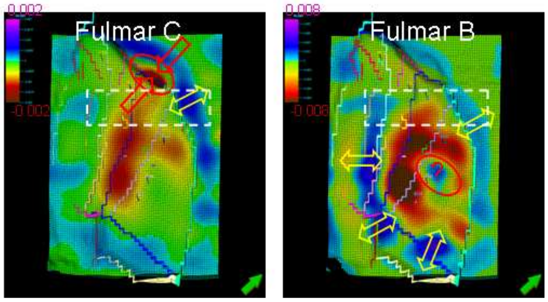

Figure 4: Inverted volumetric strain for the upper two reservoir units: Fulmar C (left) and Fulmar B (right). The inversions are from averaged time-strains at the Hod Fm and were obtained using multiple sources.

Figure 3 shows the inverted results for the Fulmar B sand. Taking the VISAGE simulated results as reference, several features are identified: the larger extensions at the reservoir boundaries including the south panel (yellow arrows), also the absence of compaction in the Central part of the Eastern Panel (red circle). The undershoot zone is represented by the dashed white line and appears as an apparent uncompacted area.

The inversions using multiple source locations, in Figure 4, have clearly higher resolution in contrast with the single source analysis shown in Figure 3, but the main features are preserved. Overall, larger than expected extensions at the reservoir boundaries are observed (yellow arrows). This could be caused by smaller pressure support, i.e. mainly compaction drive. Similarly, the south panel shows no evidence of compaction for the C and B sands, indicating that the area remains largely undepleted. The persistent anomaly at the centre of the Eastern Panel, observed also on the warping results within the reservoir (Grandi et al. 2010), can be tentatively interpreted as facies degradation. The striking feature at the NW corner of compaction on Fulmar C (red circle) at opposite end of the fault outside the reservoir hints to fault activity.

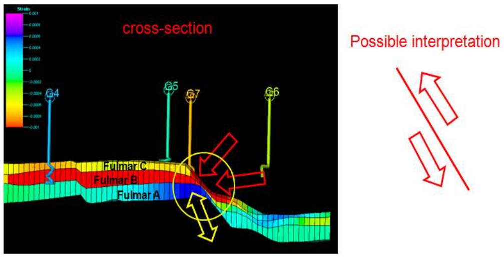

Figure 5: NW-SE reservoir cross section shows clearly the compression at the top caused by lateral-shifts of the side-burden on top of an underburden relaxation across the fault.

The feature at the NW corner in Fulmar C points to accumulation of compressive stress opposite to the N fault; a cross section is shown in Figure 5 for easier interpretation. Such a stress load after sufficient build up may cause the fault to slip. There is evidence to suggest that some faults have reactivated.

The proposed inversion methodology has not only proved useful as a tool for reservoir characterization, providing information of depletion patterns. It has also put in evidence facies degradation and demonstrated its potential as a means to monitor stress accumulation.

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