

# FEASIBILITY OF INVERTING 3-D FTG DATA FOR RESERVOIR MONITORING

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## Abstract

Three-Dimensional Full Tensor Gradiometry (3-D FTG) acquisition system takes ultra sensitive real-time measurements of small gravity changes (gradients) caused by density differences in all directions. We have undertaken a numerical examination of the feasibility of using this system for reservoir monitoring. Special gravity modeling and inversion algorithms that can describe and predict the dynamic behavior of a hydrocarbon reservoir have been developed and tested on synthetic FTG data based on realistic 4-D petrophysical models. Our inversion yields estimates of uncertainty in hydrocarbon production data. Results show that the technique is robust and is particularly useful for direct GOC monitoring and CO<sub>2</sub> injection in heavy-oil reservoirs at moderate depths.

## Introduction

The Bell Geospace 3-D FTG acquisition system is a cost-effective high-precision marine gravity gradiometry technology that measures the full spectrum of the multi-component gravity gradient field as well as the magnitude of the gravity field itself. Five independent Tensor measurements are recorded. These data are taken as a part of the routine data gathering process. The FTG survey equipment has a sensitivity of 0.5 Eötvös (Eö), i.e. better than 0.1 mGal per km. Positioning is achieved using the standard Differential GPS techniques with an accuracy of better than 1 m. Hence, this system can accurately measure extremely small changes in density in all directions at prospect level resolution comparable to that of seismic reflection. The technique has been successfully applied to image both structural and lithological contacts in several challenging areas of the North Sea (Murphy et al., 2002). Here, we study the effect of production processes on the density of reservoir rocks. The objective is to determine the feasibility of using ultra-sensitive real-time FTG measurements for mapping small ("4-D") density changes caused by changes in fluid saturation and pressure during the production process. We will attempt to answer the following question: can differences between the base and monitored gravity anomalies be attributed to dynamic processes in the reservoir? To answer this question positively, we will develop special forward modelling and regularized inversion schemes that enhance fluid-related density anomalies of the reservoir. These anomalies might otherwise be masked by acquisition and processing artefacts. Our schemes will be tested on five 4-D petrophysical models being referred to as models A-E.

## Methods and Results

*Forward Modeling:* Our 3-D finite-element density model consists of  $M$  rectangular prisms, each  $j$ th prism having a fixed density contrast  $\rho_j$  to some constant background value  $\rho_0$ . The gravity potential at the  $i$ th observation point has the form

$$g_i = G \sum_{j=1}^M a_{ij} \rho_j, \quad (1)$$

where  $G$  is the gravitational constant and the matrix elements  $a_{ij}$  describe the influence of the  $j$ th prism on the  $i$ th gravity value. Differentiating eq. (1) with respect to the receiver coordinates, the  $i$ th FTG field value may be defined as  $\mathbf{G}_i = \nabla \nabla g_i$  (Dransfield, 1994). In the above equation, the density can be expressed as

$$\rho = (1 - f)\rho_s + f\rho_f, \quad (2)$$

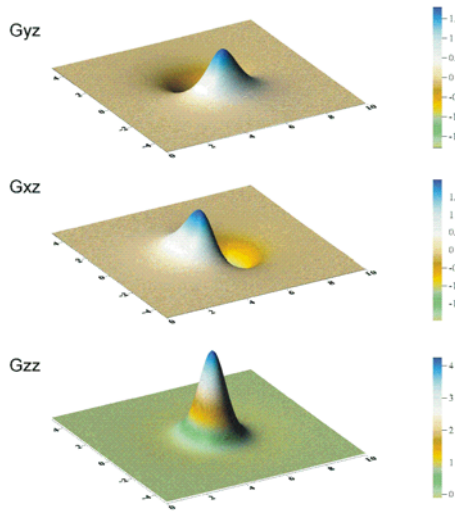
where  $f$  denotes the porosity,  $\rho_s$  the density of rock matrix (dry frame), and  $\rho_f$  the density of three-phase pore fluid given in turn by

$$\rho_f = S_O\rho_O + S_W\rho_W + S_G\rho_G, \quad (3)$$

$S_O$ ,  $S_W$ , and  $S_G$  being saturation values for the oil ( $O$ ), water ( $W$ ), and gas ( $G$ ) constituents.

**Table 1:** Saturation values and maximum 4-D density and gravity changes in models A and B.

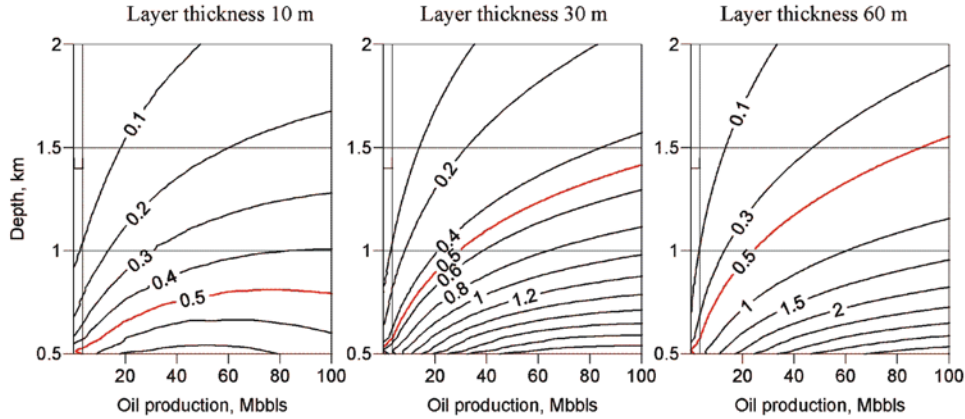
Model	$S_O$	$S_G$	$S_W$	$\Delta\rho$ (g/cm <sup>3</sup> )	$\Delta\mathbf{G}$ ( $\mu\text{Gal}$ )
A	0.78	0.00	0.22	0.036	0.9
B	0.62	0.04	0.34	0.25	6.0



**Figure 1:** Teal South model B: change of  $\mathbf{G}$  (Eö) due to gas-oil replacement.

Eqs. (1)-(3) were used to calculate 4-D anomalies of the vector  $\mathbf{G} = \{G_{xz}, G_{yz}, G_{zz}\}$  in the Teal South (GoM) reservoir models A and B represented by lateral movements of WOC and GOC, respectively. It is assumed that these movements are due to production-related changes in fluid saturation and pressure between exploration phases I and II. The depth of the  $X \times Y \times Z$  reservoir layer was set to be 1200 m. Other parameters are as follows:  $X = 200$  m,  $Y = 1500$  m,  $Z = 10$  m,  $\rho_s = 1.441$  g/cm<sup>3</sup>, and  $f = 0.29$ . The saturation values are presented in Table 1. Figure 1 shows 3-D plots of the gradient vector  $\mathbf{G}$ . The mapping of the layer edges by the off-diagonal components is particularly interesting. However, it appears that only model B produces an observable gravity effect, as illustrated in Figure 1 (see also Table 1). The accuracy of FTG measurements is not sufficient to map WOC in model A. Since 4-D density changes are directly related to oil production, eq. (1) can

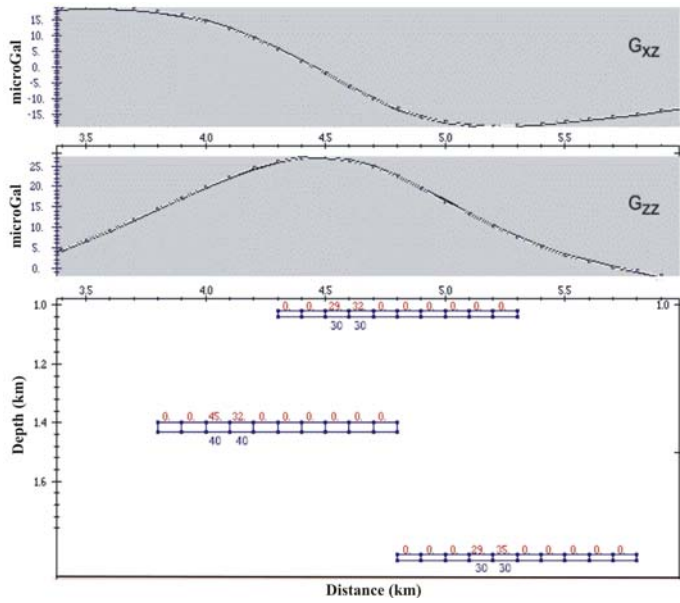
be used to constrain the history matching process as a part of reservoir simulation. This is illustrated in Figure 2.



**Figure 2:** Map of vertical gravity gradient  $G_{zz}$  (Eö) versus reservoir depth (km) and oil production (Mbbls) (model B,  $Y/X = 2$ ). A quantitative relationship between gravity effects and reservoir parameters is established.

*Regularized Inversion:* Let  $\mathbf{G}^I$  and  $\mathbf{G}^{II}$  be the base ( $I$ ) and repeat ( $II$ ) FTG surveys. Eq. (1) defines the relationship between these surveys and the corresponding density structures  $\rho^I$  and  $\rho^{II}$ . The 4-D inverse gravity problem of estimating  $\Delta\rho = \rho^{II} - \rho^I$  from  $\Delta\mathbf{G} = \mathbf{G}^{II} - \mathbf{G}^I$  may be formulated using Tikhonov's method of undetermined Lagrange multipliers, which permits the

incorporation of *a priori* information about the maximum compactness of anomalous sources along several axes (Barbosa and Silva, 1994). This method has proved to be versatile. It is particularly applicable to reservoir monitoring since the shape of the gravity sources (the geometry of reservoir) is often known from time-lapse surface and borehole seismic data.



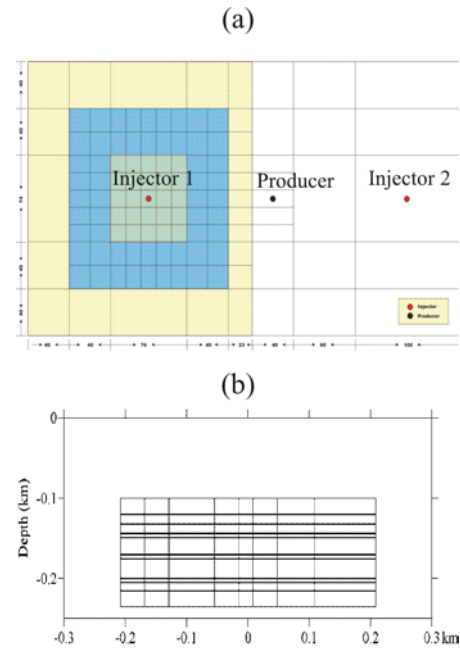
**Figure 3:** 4-D FTG inversion in model C:  $G_{xz}$  and  $G_{zz}$  curves (dotted line – observed data, solid line – predicted data), exact (below cells) and recovered (above cells) 4-D density changes between surveys *I* and *II* (in  $\text{kg/m}^3$ ).

monitor the movement of the injected steam within the  $200 \times 60$  m heavy-oil reservoir. When saturation changes as a high-temperature steam zone invades, density changes give a detailed map of the heat movement (cf. Table 2). Clearly, there is no ambiguity in interpreting temperature change from density change. In particular, Table 2 shows that the resistance of the cold viscous oil rim in the fractures prevents the steam from displacing the oil downwards.

To investigate potential applications of FTG monitoring to the steam pilot, a fifth reservoir model (E) was created using the thermal multi-block reservoir simulator. The  $417 \times 234 \times 120$  (m) model is represented by the irregular grid, as shown in Figure 4. The grid size varies from  $23 \times 40 \times 20$  (m) to  $100 \times 74 \times 20$  (m). Figure 4a shows two injector wells 1 and 2 (from left to right) and one producing well between injectors 1 and 2. Model E was created to study the areal advance of the steam zone, given the porosity map in Figure 5a and the constant initial temperature  $20^\circ\text{C}$ . The temperature distribution in Figure 5b was converted to the density model  $\rho^I$ . The initial density was  $\rho^0 = 0.8\rho^I + \delta\rho$ , where  $\delta\rho = \xi \max(\rho^I) / 4$  and  $\xi$  is the random variable in the range  $[0,1]$ . The result of inversion is denoted as  $\rho^{inv}$ . Through inversion, an improved estimation of density changes is achieved (Figures 5c,d).

Figure 3 shows the results of inversion in model C. This model consists of a target  $200 \times 40$  (m) density anomaly of  $40 \text{ kg/m}^3$  at a depth  $z = 1.4$  km. Two additional  $200 \times 30$  (m) density anomalies of  $30 \text{ kg/m}^3$  are located above and below the target ( $z = 1.00, 1.85$  km). The input data consist of  $G_{xz}$  and  $G_{zz}$  components with the addition of 4% random Gaussian noise. It is seen that all density anomalies are adequately retrieved without pre-processing.

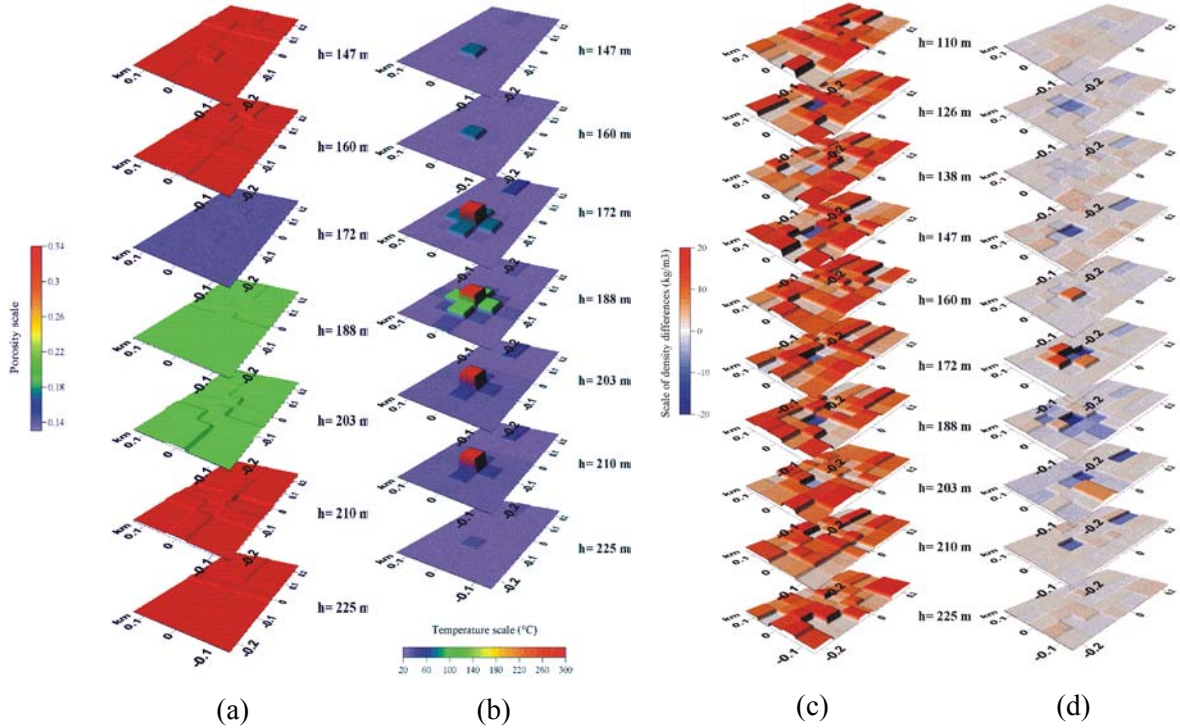
Next, we simulate density changes during monitoring steam injection in Alberta tar sands (the Steepbank-HASDrive project) using the simple Gardner's simple velocity versus density relationship. Here, the objective of gravity inversion is to



**Figure 4:** (a) ( $xy$ ) and (b) ( $xz$ ) sections of model E.

**Table 2:** Inversion results in  $10 \times 3$  grid model D: exact versus recovered (in brackets) density changes ( $\text{kg/m}^3$ ) in grid cells.

200 m										
60 m	0(7)	34(20)	43(43)	53(64)	75(73)	75(73)	53(64)	43(43)	34(20)	0(7)
	0(2)	0(5)	25(17)	39(39)	53(53)	53(53)	39(39)	25(17)	0(5)	0(2)
	0(-2)	0(1)	0(3)	25(24)	43(42)	43(42)	25(24)	0(3)	0(1)	0(-2)



**Figure 5:** Output of thermal reservoir simulator (model E) in the vicinity of the vertical injection well 1: (a) porosity map versus (b) temperature distribution after 212 days of continuous steam injection (horizontal slices  $z=h$ ). Results of 4-D FTG inversion: (a)  $\Delta\rho^0 = \rho^{II} - \rho^0$  and (b)  $\Delta\rho = \rho^{II} - \rho^{inv}$  (densities in  $\text{kg/m}^3$ ).

## Discussion

Good-quality 3-D FTG data can be produced during the reservoir monitoring process, and may be used for large-scale production history matching. Interpretation of these data requires reliable and efficient inversion methods, which adequately incorporate prior information. This paper has addressed all the above questions in the context of regularization theory. Questions of optimal FTG acquisition design and of resolution of the computed estimates have been answered. The results demonstrate that FTG data can be used for reservoir monitoring in conjunction with time-lapse seismic data.

## Acknowledgements

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