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# Estimation of reservoir fluid saturation from seismic data: amplitude analysis and impedance inversion as a function of noise

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**SUMMARY**

Noise in seismic data can create significant challenges for the integration of 4D information into seismic history matching procedures. Impedances derived from a seismic inversion are usually compared to impedances provided by the coupling between a fluid flow and a petro-elastic model. The problem is that uncertainties associated with noise in seismic data are rarely carried though all the seismic inversion steps. And the noise in seismic data can alter the correlation between acoustic impedance and fluid saturation, resulting in erroneous estimates of reservoir properties.

We hypothesize that the amplitude domain could be a better option than the impedance domain for seismic history matching, considering seismic noise. To verify this hypothesis we analyse amplitude and impedance changes as a function of water saturation and seismic noise. We demonstrate that the noise in seismic data causes higher variations on seismic inversion results than on amplitudes. A cross-domain comparison suggests that these impedance variations can be as high as their values derived from the seismic baseline survey.

These results indicate that matching time-lapse seismic and fluid flow data in the amplitude domain may be more reliable than using the impedance domain - in the presence of strong seismic noise. Errors in seismic data, such as noise, need to be considered when undertaking seismic history matching, and proper uncertainty analysis is required for accurate reservoir predictions.

**Key words:** seismic history matching; amplitude; impedance; time-lapse seismic; fluid flow model

## INTRODUCTION

Fluid flow models are an important management tool for oilfield development. These models are calibrated evaluating the mismatch between modelled and observed data which guides updates of reservoir properties such as permeability and porosity. Once hydrocarbon production starts, fluid distribution within the reservoir is likely to change. The ability of time-lapse (4D) seismic to map these fluid changes has proved to be crucial for modern reservoir development. The inclusion of seismic data in the calibration of fluid flow models is an area of active research (Stephen and Kazemi, 2014).

In general, integrating geophysics and reservoir engineering data is performed in one of the following domains (Figure 1):

- Fluid saturation and/or pressure
- Seismic impedance
- Seismic amplitude

Data in the fluid/pressure domain is a standard output of the flow simulator used to model production data. Thus, from an engineering perspective, data integration on this domain would be the first choice. Then information can be directly applied without any domain conversion or issues associated with global objective functions involving production data and maps derived from seismic data (Sagitov and Stephen, 2012). However from a geophysics perspective, this domain is the most complex as it requires two inversions that involve compounding errors and non-uniqueness issues Yet the ability to distinguish between pressure and saturation effects relies on the 4D amplitude versus offset (AVO) response of the reservoir (Tura and Lumley, 2000; Landrø et al., 2003), and uncertainties in the rock physics models remain (Johnston, 2013).

The impedance domain is also an option and as an interval property, it is arguably more intuitive than seismic amplitudes (Stephen and Macbeth, 2006). However, the problems with using impedances are twofold: (1) they require undertaking a seismic inversion procedure that introduces uncertainty and nonuniqueness issues; and (2) petro-elastic modelling is used and these models are a source of uncertainty as they are based on available rock and fluid physics data (core, logs, PVT, etc.) which are associated with measurement errors (Mavko et al., 2011).

Another option for integrating geophysics and reservoir engineering data is in the seismic amplitude domain (Kumar and Landa, 2008). Of the procedures involved in seismic history matching, this option is the most straightforward as there is no need for seismic inversion. However, it is the most difficult for engineers because it is not easy to quantitatively associate seismic amplitudes with reservoir properties and joint modelling of flow and seismic amplitude is required.

It is necessary to carry the uncertainties through all inversion steps to match the seismic and fluid flow model data in the fluid/pressure and impedance domains. Transferring uncertainties in a forward modelling process, such as going from simulation to seismic amplitude, involves much simpler, more stable and more straightforward processes. However, in practice, the impedance domain is widely used and most of the inversions performed are deterministic (Landa and Kumar, 2011).

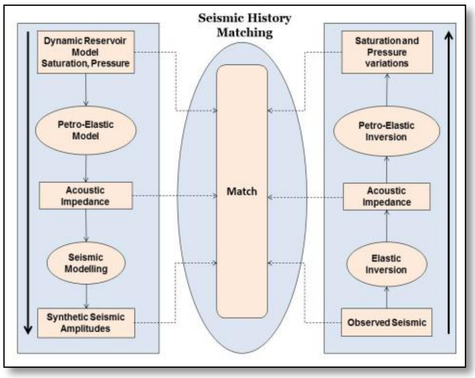


**Figure 1: Diagram presenting the domains in which seismic and fluid flow model data can be integrated.**

As an example, Figure 2a contains the output of the water saturation changes from a fluid flow model built for a history matching study (Maschio et al., 2013). We forward model synthetic amplitudes for two different production times and use them as inputs into a seismic inversion, deriving relative acoustic impedances. Random Gaussian noise is also added to the amplitudes. The noise free amplitude differences (Figure 2b) clearly identify main features of the water changes map (Figure 2a). The map of amplitude differences with noise (Figure 2c) also shows the main water trends. On the other hand, regions where the 4D signal is weaker are not identified and overall the image becomes noisier.

The noise free impedance changes in Figure 2d and the water saturation changes in Figure 2a, present similar trends; however, the overall quality of the image is poorer because of the variations of the seismic inversion results. We also observe the main water saturation changes in the map of impedances with noise (Figure 2e). However, the impedance estimates of the seismic inversion oscillate more due to the noise in the amplitudes.

Qualitatively, all maps indicate the observed main water trend (Figure 2a). Amplitudes clearly have a higher correlation with the water changes than impedances. However, adding noise to the amplitudes has a direct impact on the quality of the impedance estimates from the seismic inversion and quantitative analyses would certainly be compromised.

Thus, once we consider seismic noise, the amplitude domain could be a better option than the impedance domain for seismic history matching. To verify our claim, we explore a 1D synthetic problem obtaining amplitude and impedance behaviour as a function of water for various levels of noise in seismic data. This approach provides an estimate of the uncertainties associated with the noise in seismic data and how they can affect identification of the fluid changes in the amplitude and impedance domains.

Our experiment replicates an oil production scenario where water gradually replaces oil after the onset of production. To obtain amplitude and impedance as a function of water saturation, we fluid substituted the original logs with water saturations from 10 to 100%. Each resulting log is used as an input to the workflow described below.

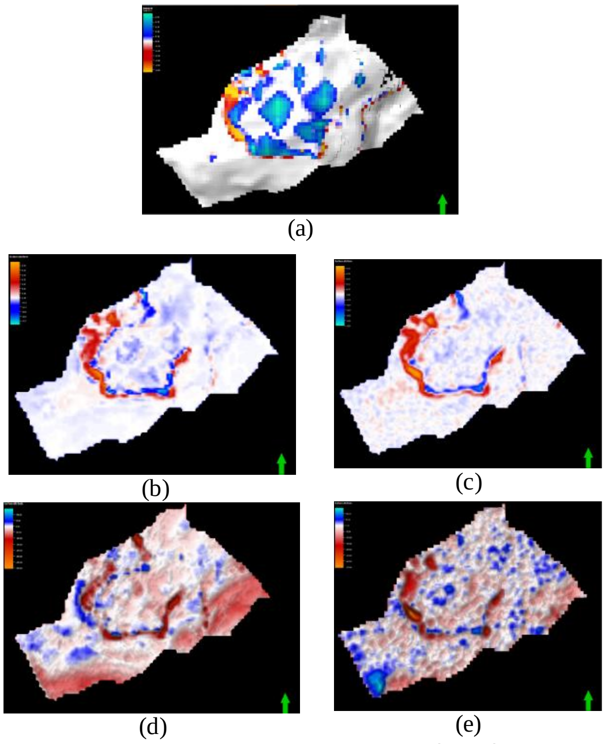


**Figure 2: 4D seismic modelling based on fluid flow model outputs. (a) Water saturation changes. Noise free amplitude differences (b); and with added noise (c). Noise free acoustic impedance differences (d); and with added noise (e).**

## METHODS

### Synthetic seismic attributes

Figure 3 presents the workflow developed to generate synthetic seismic attributes. We use compressional and shear wave velocities and densities from well-log data. Amplitude information is obtained by convolving these logs with a bandpass wavelet (with corners 5, 10, 80 and 90 Hz). We add random Gaussian noise with a standard deviation equal to a percentage of the maximum amplitude of the noise-free amplitudes. We model signal-to-noise (S/N) ratios of 10, 5 and 3 where the noise is in the same frequency band as the seismic data. Due to its simplicity and fast processing, a coloured inversion code (Lancaster and Whitcombe, 2000) is applied to obtain relative acoustic impedances. We then convolve the logs with the same wavelet used to generate the amplitudes, and obtain a smoothed version to help quality control the inversion results. Finally, noise-free trends are obtained by applying the same procedure described above. These trends were then used as references.

## RESULTS

### Time-lapse attribute versus water saturation changes

We first calculate the root mean square (rms) of amplitude and impedance changes in the region of interest. Then we plot amplitude and impedance changes as a function of water saturation changes and seismic noise. We consider water saturation of 10% as our baseline and define time lapse information in terms of monitor minus baseline. The noise is added to each survey before the subtraction. The curves S/N of 10, 5 and 3 are the averages of 9 independent noise realizations. Then the standard deviations are derived based on these 9 different noise realizations.

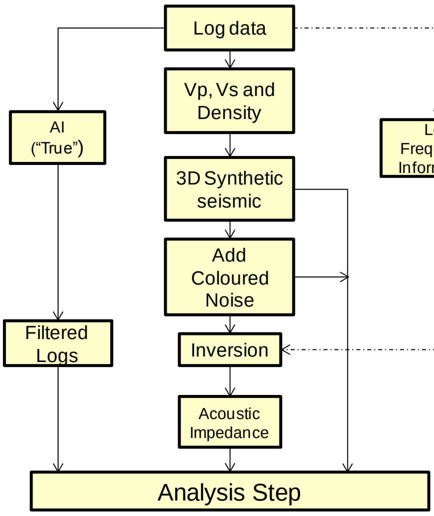


**Figure 3: Workflow applied to generate synthetic amplitudes and impedances.**

Figure 4 presents amplitude changes versus water saturation changes. The green line represents the noise free amplitude changes. The curves for S/N=10, S/N=5 and S/N=3 are the blue, red and black lines, respectively. The error bars indicate their respective standard deviations.

Figure 5 presents impedance changes versus water saturation changes. The green line represents impedance changes that do not contain noise and the pink curve is the impedance changes derived from the bandpassed log. The curves for S/N=10, S/N=5 and S/N=3 are the blue, red and black lines. The error bars indicate their respective standard deviations.

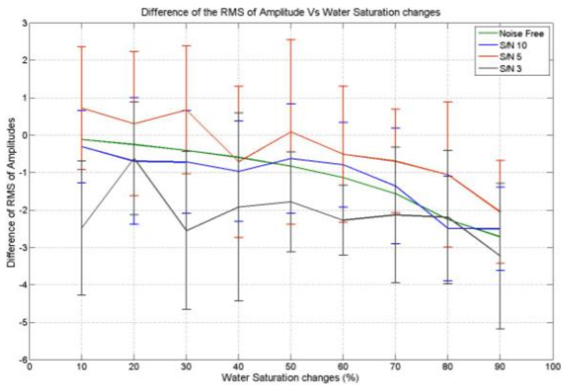


**Figure 4: Amplitude variation versus water saturation changes for noise free data and S/N ratios 3, 5 and 10.**

**Quantitative cross-domain comparison**

For a cross-domain interpretation we define a *4D ratio* criteria:

$$\mathbf{4DRatio} = \frac{abs(std(rms(MonitorAtt) - rms(BaselineAtt))}{rms(BaselineAtt)} \qquad \mathbf{(1)}$$

This indicates the amount of the variation the noise introduces to the attributes at each water saturation level in relation to the attributes from the baseline survey.

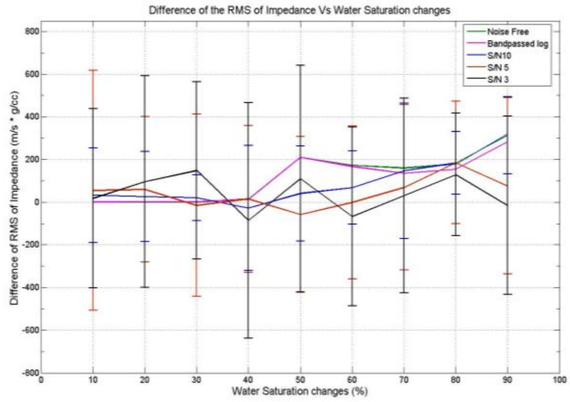


**Figure 5: Impedance Variations versus water saturation changes for noise free and S/N of 3, 5 and 10.**

The standard deviations in Equation (1) are represented by the error bars in Figure 4 and Figure 5. We use absolute values to enable a comparison between amplitude and impedance. For the same reason we take the rms of the baseline attribute as a normalization factor to allow cross-domain comparison.

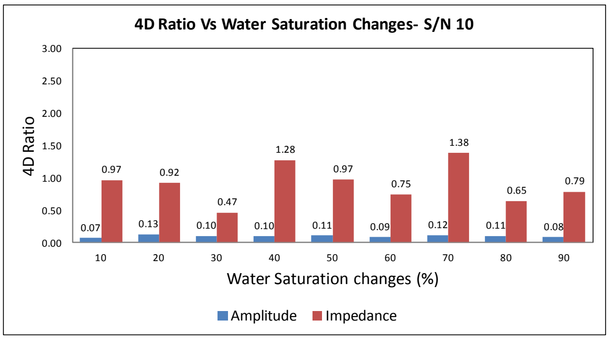


**Figure 6: Absolute ratio between standard deviation and average attribute per water saturation changes for S/N=10.**

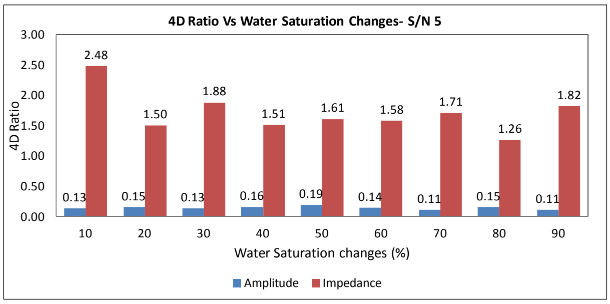


**Figure 7: Absolute ratio between standard deviation and average attribute per water saturation changes for S/N=5.**

## ANALYSIS

As expected, in Figure 4 we observe that amplitude values decrease as we increase water saturation for all noise levels. Also note how the average for S/N=10 (blue line) is closer to the noise free trend (green line) than the averages for S/N=5 (red line) and S/N=3 (black line). This pattern indicates that the errors are proportional to the amount of noise added. Further, amplitude has a response to water saturation changes <50%, while in Figure 5 we observe that impedance does not have a response below a 50% water saturation change.

However, we observe errors in the amplitudes for S/N=5 and S/N=3 that could compromise its use as a fluid change indicator for water saturation changes <50%.

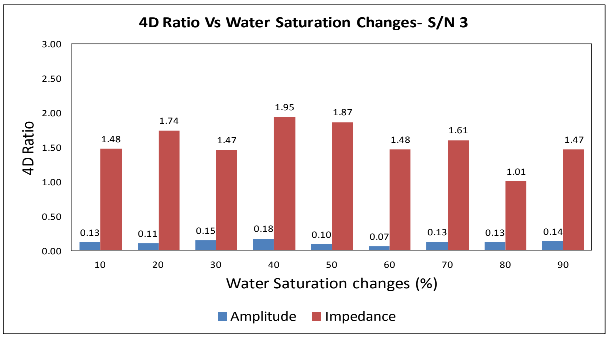


**Figure 8: Absolute ratio between standard deviation and average attribute per water saturation changes for S/N=3.**

In Figure 5 we observe that impedance values increase proportionally with water saturation. Two sources of error give us the uncertainties observed in the inversion results presented in Figure 5: (1) an inherent inversion error - defined as the very small difference between the noise free condition (green line) and the band-passed log (pink line); and (2) the effect of the noise added to the amplitudes – at the relative impedance estimate. The first source does not contribute much because the smoothed logs have the same frequency bandwidth as the seismic. Thus, most of observed uncertainties are caused by the noise in the amplitudes. These variations are also proportional to the amount of noise added.

The 4D ratio values in Figure 6 indicate that amplitudes are consistent with the level of the noise added to the amplitudes (approximately 10%); while the variations in impedances are comparable to the baseline signal itself (values around 1). This means that the effects of the noise on the results of the seismic inversion can generate uncertainties 10 times bigger than the ones observed in the amplitude domain.

Comparing the 4D ratios for S/N=5 and S/N=3 (Figure 7 and Figure 8, respectively) we note that the amplitudes remain proportional to the amount of noise initially added. While impedances present variations that are almost 2.5 times the impedance values observed on the baseline survey (Figure 7).

These results suggest that amplitudes are more stable than impedances, considering noise in seismic data. As a major consequence, the use of impedances as an indicator of fluid changes can lead to the incorrect update of reservoir properties.

## CONCLUSIONS

We derived amplitude and impedance changes as a function of water saturation changes for S/N=10, S/N=5 and S/N=3. Our analysis between the domains indicates that amplitudes are more stable than impedances. A proposed 4D ratio for cross-domain comparison demonstrate that noise effects in seismic inversion can generate uncertainties as high as the impedance derived from the baseline survey; while amplitude uncertainties remain proportional to the amount of noise added. Thus, matching time-lapse seismic and fluid flow data in the amplitude domain is likely to be more reliable than in the impedance domain. Further, more accurate workflows for seismic history matching should consider a nonlinear uncertainty analysis of reservoir seismic modelling and seismic inversion.

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