Facies-based inversion through the asset lifecycle

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This paper was prepared for presentation during the 15th International Congress of the Brazilian Geophysical Society held in Rio de Janeiro, Brazil, 31 July to 3 August, 2017.

1. Introduction – the low frequency conundrum

Seismic lacks low frequencies, so for an absolute seismic inversion (which allows us to be quantitative) a so-called Low Frequency Model (LFM) is required.

Starting from an empty LFM, we would of course like to post Sand Vp values where there is Sand, Shale Vp values where there is Shale, etc. (for a minimum of 3 impedances and for all facies expected).

But unless we have very favourable circumstances where facies can be interpreted directly from the seismic, we don't know in any great detail where the facies are located in the subsurface (in fact, understanding the facies distribution is one of the main aims of seismic inversion). So populating a LFM as outlined in the previous paragraph is not possible in most cases.

The LFM's constructed to date are therefore compromised to a smaller or larger degree (for instance, using well log interpolation guided by picked horizons leads to averaging). Importantly during the inversion the seismic cannot 'fix' a compromised LFM as – we come full circle here – seismic lacks low frequencies!

2. Facies-based inversion

A modern approach to better low frequency modelling (Kemper & Gunning, 2014) is to over-specify the low frequency information (by inputting a LFM for each of the facies expected), and to let the inversion decide what the ultimate LFM is. In other words, the LFM used is not an input (as per Section 1), but is inverted for!

This new inversion is facies-based (i.e. outputs not only impedances but also a facies image) and works by iterating (until convergence) between the following two steps:

- Step a) Invert seismic for impedances given facies
- Step b) Invert the impedances for facies

Note that when Step a) is first run, no facies are used (as a facies image is not available at the start). In other words, the first incarnation of Step a) is a classical inversion as outlined in Section 1.

The two steps help one another. Clearly better impedances lead to a better facies estimate. The reverse is true also, as in each iteration of Step a) the LFM is re-created based on the facies estimate. So here we can do what was impossible in Section 1: copy Sand Vp LFM values where there is Sand, copy the Shale Vp LFM values where there is Shale, etc.

Because in the inversion loop we always have an (ever improving) facies estimate, we can (optionally) further constrain the inversion by promoting facies continuity (typically set higher laterally than vertically) and by preventing illegal hydrological facies combination (i.e. no Water-bearing Sand above Oil-bearing Sand).

The implementation is a Bayesian one, which means all inputs, the most important ones being the seismic (typically partial angle stacks), the wavelets and per-facies LFM's, all come with an assessment of uncertainty. And so are the outputs, impedances and facies (for an impedance, a continuous property, you can specify the uncertainty numerically as e.g. a standard deviation. This is not possible for discrete facies. Therefore multiple equi-probable facies realisations can be generated, for subsequent analysis).

3. Application from Exploration to Production

The parametrization of facies-based inversion changes from Exploration through to Production. In Exploration for instance, the inversion window is usually quite large, the number of zonations in that window quite small (as detailed sub-divisions of the zonations are not yet available), and the number of facies inverted for will be small, i.e. you would perhaps invert for Shale, not (yet) Hard-Shale and Soft-Shale, as limited log data does not (yet) allow such a discrimination. Conversely, in production the reverse is applicable: a small inversion window targeted on the reservoir, many zonations, and a larger number of specific facies. See Figure 1 for a cartoon.

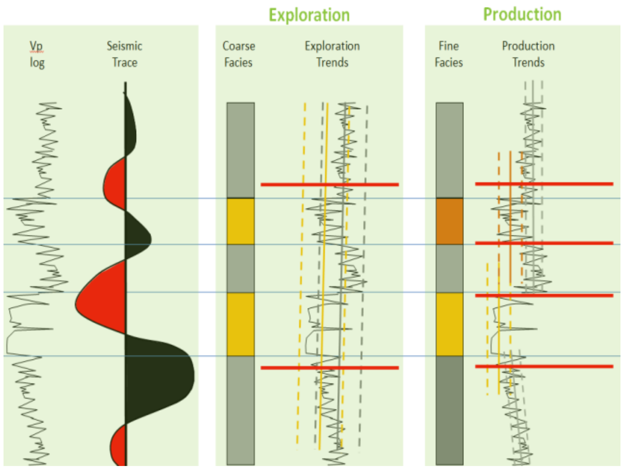

*Figure 1: Left: Vp log and seismic trace at well location. Middle: in an Exploration inversion, we may decide on only two faces (**Sand** and **Shale**), the trends/LFM's of which are shown. Note there are 3 zonations. Right: in a Development or Production setting, we may decide on only four faces (**CleanSand**, **DirtySand**, **SoftShale** and **HardShale**), the trends/LFM's of which are shown. Note there are 5 zonations*

Given these considerations, we will present Exploration, Appraisal/Development and Production case studies using facies-based inversion.

In the Exploration case study we invert the Willem survey offshore NW Australia (see Sams *et. al.*, 2016 for more details). The dataset consists of 2400 km^2 of seismic (four partial angle stacks) with only 2 wells with elastic logs (and a further three wells without elastic logs, and one well, Pyxis-1, of which at the time we only knew it's surface location and that it was a gas discovery).

In this first case study, we briefly describe the typical workflow for facies-based inversion. First perform log and seismic conditioning (not done in this study, as time was limited). Then wavelets are estimated (here, one per partial angle stack), and the seismic window is chosen (large, as we are in an Exploration setting), along with its zonations (here two extensive zones). Facies selection is critical for this facies-based inversion (here we chose 4 facies per zonation), and a LFM is constructed per facies (per facies we make depth trends of impedances referenced to a datum – in this study the seabed; these depth trends are then 'hung off' a horizon equivalent to that datum). Facies proportion per zonation are estimated in discussion with the geologist (here constant values; later in the asset lifecycle these can become e.g. maps), and the inversion is run (click a button). The most important step, as always, is inversion QC.

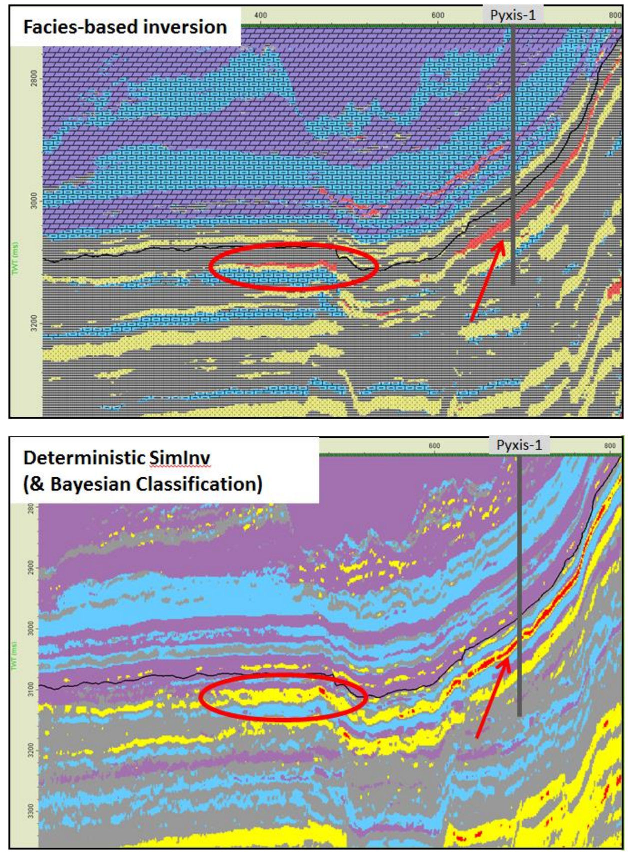

Figure 2: Facies-based inversion (top) and model-based simultaneous inversion followed by Bayesian classification to facies (bottom), of the Willem 3D survey. Grey = Shale, yellow = Water-bearing Sand, red = Gas-bearing Sand, Blue = Limestone, Purple = Marl.

Figure 2 (top) shows the facies-based inversion result (facies; impedances are not shown) on an arbitrary line through the Pyxis-1 gas discovery. For the sake of comparison we also ran model-based simultaneous inversion, which requires a LFM as an input. Elastic logs were first synthesized using rock physics models for the 3 wells that didn't have these profiles; subsequently the 1 LFM needed was interpolated from the 5 wells. This however only gives impedances, and so we subsequently derived facies using Bayesian inversion (see Figure 2 – bottom).

The facies-based inversion result looks more credible. This can be substantiated by (i) looking at the two ellipses (the facies-based inversion finds a lovely GWC not seen by Simultaneous Inversion followed by Bayesian classification) and by (ii) looking at the two arrows (the facies-based inversion images a continuous gas-bearing sand and predicts 18.2m of gas column at Pyxis-1 – later we learned that we were only 1m short; Simultaneous Inversion followed by Bayesian classification does find the gas leg, but it is broken up, has Water-bearing Sand (yellow) above and below the Gas-bearing Sand (breaking hydrological rules), and the gas column is too small).

For an Appraisal/Development case study, we turn to the Paleocene Avalon discovery, Central North Sea (Zabihi Naeini and Exley, 2016). In this stage of the asset lifecycle, we need to understand the impact of key uncertainties on Gross Rock Volume, Oil in Place (OIP), Connectivity, etc., to assist in rightsizing the number of producers and infrastructure. In this case the biggest unknown is the amount of OIP, and therefore the facies-based inversion was repeated a number of times with different estimates of prior proportion of Oil-bearing Sand facies. This is investigated in Figure 3 below.

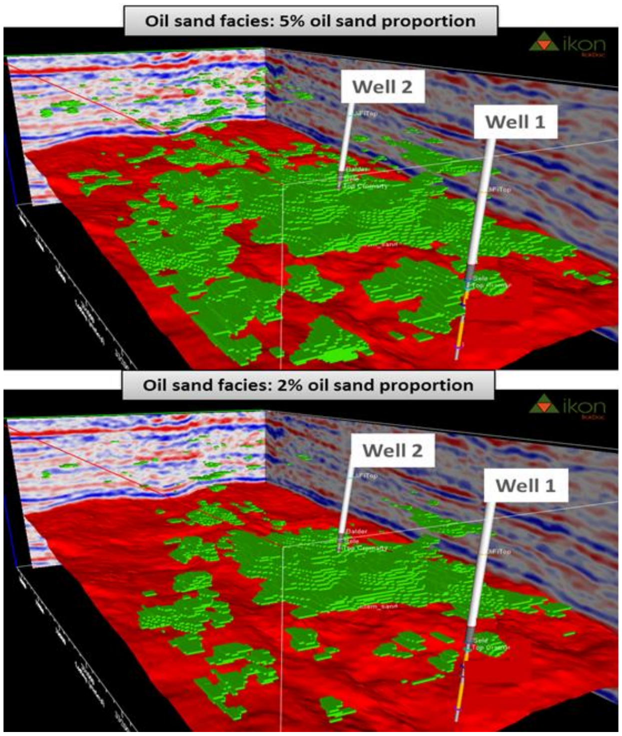

Figure 3: The Avalon facies result of facies-based inversion at 5% (top) and 2% (bottom) prior Oil-bearing Sand proportion.

The difference in OIP (percentage Oil-bearing Sand) clearly has a significant effect on development scenarios and reserves. Developing Avalon with the data available or acquiring further data to reduce uncertainty is a decision to be considered (using e.g. the Value of Information method).

In a production setting, the objective of seismic inversion is to assist in locating untapped hydrocarbons (by-passed, undrilled fault blocks, etc.). This is also true for the Forties field, which came on production in 1975. The first 3D survey was shot in 1988, which forms a 'baseline' for 4D studies (apostrophes are used, as this survey is definitely not pre-production), and which is available to this case study. Five monitor surveys have been acquired since, of which the last one (2013) was used here. For more detail refer to Waters *et. al.*, 2016.

Facies-based inversion as discussed so far is a 3D inversion, and therefore we applied this technique to the 1988 and 2013 surveys individually (see Section 5 below where 4D facies-based inversion is discussed). In Figure 4 we show a map view of the facies-distribution in 1988 (top) and 2013 (bottom).

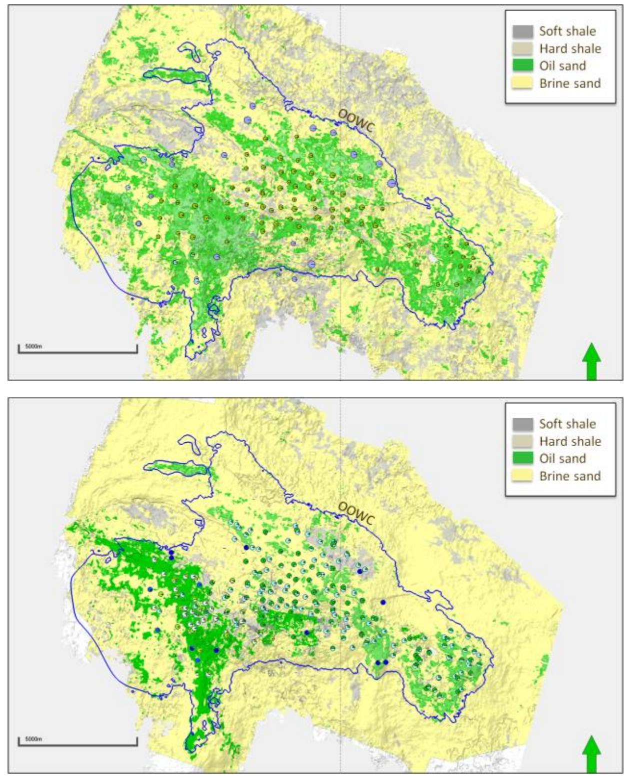

Figure 4: Facies image top 20m of the Forties reservoir, 1988 (top) and 2013 (bottom)

The massive 'sweep' signature to the Southwest is evident, but detailed analysis shows finer details also (e.g. 'halos' around water injectors). This results are now used by the operator (in a holistic sense; i.e. by incorporating other data such as offset wells, 4D differences, etc.) to assist in infill-drilling.

4. Look ahead

Facies-based seismic inversion is powerful because facies typically have distinct elastic properties (which are of course why facies transitions are the primary cause of loops on the seismic). But they usually have distinct resistivities too! So a facies-based seismic *and* CSEM inversion makes sense. One research study was completed 2016. Also for this case study we have limited show rights. However, we can show Figure 5 below. In this case study a cascaded approach was followed, i.e. facies-based seismic inversion was run first to estimate the location of the various facies. From this a resistivity prior model was constructed for use in a subsequent facies-based CSEM inversion step. The 'focusing' of the resistivity anomaly is clearly superior to CSEM-only inversion.

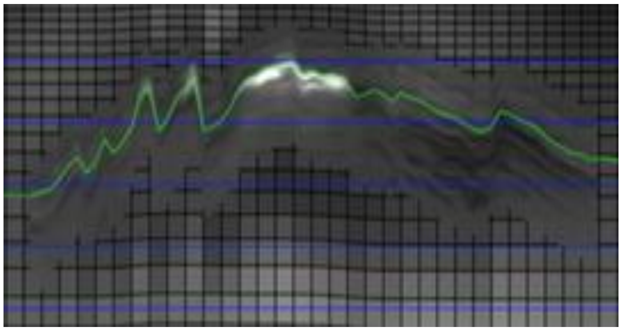

Figure 5: Resistivity from a simultaneous facies-based seismic and *CSEM inversion. Note that the (very focussed!) anomaly is where you expect it (at top of structure), and also notice the layering, typically absent from CSEM-only inversion.*

As alluded in Section 3 (the Forties case study), a 4D facies-based inversion would be powerful. Illegal temporal facies transitions (example: in Figure 4 where just under the 'OOWC' label we see Oil-bearing Sand in 1988. After 25 years production this should in 2013 come out as Water-bearing Sand, but in fact comes out as 'Shale'?!) would not be permitted. Furthermore, any seismic difference in non-reservoir facies can't be caused by a change in saturation, so therefore has to be a change in pressure. Note that these sensible but potent 4D constraints are impossible in facies agnostic inversions.

In virtually all seismic inversion algorithms, facies-based inversion included, you forward model the seismic response (this then gets compared to the real seismic, and the residual then causes an update to the impedances, etc.). In isotropic inversion typically the Zoeppritz forward model, or derivatives thereof, are used. These forward models are driven purely by the impedances – you need not know the facies distribution for this facet of seismic inversion. However when anisotropy plays a role, the forward model *does* become facies dependent. As an example, the HTI forward model for a Sand is different to the VTI forward model for a Shale. In a facies-agnostic inversion you either have to invert with, say, the HTI forward model, hoping that the fact you use the wrong forward model in Shale does not deteriorate the result too much, or you have to invert with the higher order Monoclinic anisotropic forward model (the 'parent' of HTI and VTI), but that has too many parameters to invert for. This is likely why anisotropic inversion has a bad reputation.

In facies-based inversion the solution is almost embarrassingly straightforward: Where facies is Sand use the HTI forward model, and where facies is Shale use the VTI forward model. Prototyping has confirmed that this approach works very well indeed.

There are more facies-based research ideas, which will form the subject of later papers.

5. Conclusions

We have seen a rapid adoption of facies-based inversion over the full asset lifecycle. The reasons are as follows:

- The LFM is inverted for, whereas populating credible LFM's in conventional workflows is a huge challenge (Note that the LFM changes in 4D. Facies-based inversion can deal with that, but most facies-agnostic inversions can't, which is why mostly relative inversions (using 4D differences) have been performed to date)
- Better facies correlation at the wells is achieved, compared to conventional techniques.
- The facies image is quite akin to geo-cellular models (i.e. facies-based inversions help the geo-modeler greatly)
- Rigorous uncertainty assessment is possible through:
  - Scenario modelling (reference the Avalon case study – section 3)
  - Multiple equi-probable realisations
- In the Forties 4D case study, we performed a 3D facies-based inversion twice:
  - It showed that absolute inversion on a 4D dataset is possible
  - It achieved a good match to the production history
  - Of course to be interpreted holistically (offset wells, production data, 4D differences, …)
  - A 4D facies-based inversion should give further improvements
- Facies-based inversion opens the door to new subsurface workflows (we mentioned facies-based seismic & CSEM inversion, facies-based 4D inversion and facies-based anisotropic inversion, and more are in the pipeline).

References

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Acknowledgments

We thank Tullow Oil Plc for sponsoring this Ji-Fi project and CSIRO for their cooperation.