Facies-based Reservoir Characterisation through the Asset lifecycle

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Introduction

Reservoir characterisation is essentially the process of getting as much valuable information as possible out of a variety of data sources (wells, seismic, …) so that geological modelling and subsequent flow simulation, and key economic and technical decisions are optimally underpinned by that information.

And reservoir characterisation needs to take place at all stages of the life of an asset. In green-field exploration the database may be scarce (there may be no wells, some 2D seismic lines, …), and reservoir characterisation will be uncertain; subsequent geological modelling may be as simple as an idea in the head of a geologist (and flow simulation is not considered). Conversely towards the end of an asset's life, the database will likely be huge. It will contain multiple seismic datasets and many wells, obtained at different dates; interpretations will abound. Production will have started years ago, and the reservoir characterisation job now is to 'abstract and integrate' all this data so that the geology can be optimally represented in the geological model (of which there often are many incarnations), and that the flow simulation model is to be fully calibrated ('history matched'); ideally geomechanics is considered also, as production (and injection) alters the properties as well as the stress state…

Although there are other data sources (some of which will be addressed in the presentation), the two main ones for reservoir characterisation are data sources derived from wells and reflection seismic data. These are initially interpreted almost independently of one another (petrophysical and geological evaluations on the one hand, seismic structural interpretation on the other). However from a reservoir characterisation point of view it is the integration of these two data sources (and others, such as basin history) that is crucial. In a structural sense we see this in time/depth conversion, where well and seismic velocity data are merged; this is not further discussed in this presentation.

Here we focus on how reservoir properties can be optimally derived from well and seismic data. An important reservoir characterisation technique to (try to) integrate these two data types for property estimation is seismic inversion; we will in the presentation show that to date rock physics is often not fully part of the seismic inversion, which has adverse knock-on effects. A new inversion system that does incorporate rock physics adequately and which therefore fully integrates well and seismic data is introduced in the presentation. The crux of this new technique is that we not only invert for impedances but also for rock-type/facies; this in turn allows per-facies Rock Physics Models (RPM's) to be employed, which is key.

Conventionally seismic inversion is followed by conversion, using RPM's, of impedances to rock properties, as required by the geological model. We will show that with the new seismic inversion method this step is a natural one, as RPM's are already fully incorporated within the inversion

Facies-based seismic inversion

Seismic lacks low frequencies, so for an absolute seismic inversion (which allows us to derive quantitative rather than relative or qualitative properties) a so-called Low Frequency Models (LFM) is required (for three impedances typically – however below we only discuss Vp for ease of notation).

Starting from an empty Vp LFM, we would of course like to post Sand Vp values where there is Sand, Shale Vp values where there is Shale, etc.

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

The LFM's constructed to date are therefore compromised to a small or large degree (for instance, using well log interpolation guided by picked horizons leads to smoothing, resulting in impedance values unrepresentative of the facies present). Importantly, during the inversion the seismic cannot 'fix' a compromised LFM as – we come full circle here – seismic lacks low frequencies!

We introduce a new facies-based approach that overcomes this issue. In essence, for each facies expected (e.g. Shale, Water-Sand, Oil-Sand), a LFM representing compaction behaviour for that particular facies is constructed, and all are input to the inversion (i.e. the low frequency information is over-specified). The inversion can then decide which LFM is used where, based on the facies estimate, which is one of the quantities inverted for. So the LFM ultimately used in the inversion is an output, not an input.

As per-facies RPM's were employed in the inversion, the impedances inverted for are consistent to them. Which means that these impedances can be readily converted to rock properties: where the facies (also inverted for!) says there is Sand, use the same Sand RPM as used in the inversion to obtain, say, porosity. Same for Shale, etc…

Case studies through the asset life cycle ranging from exploration through appraisal/development to production, will be discussed which demonstrate the commercial and technical advantages gained by this new paradigm,

Finally, we shall present future plans regards facies- based inversion and reservoir characterisation.