Facies as the key to using seismic inversion for modelling reservoir properties

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Abstract

Although the general distribution of facies and corresponding reservoir properties should be predicted from geological understanding, the particular characteristics and heterogeneity of a field may not be readily anticipated, especially if well coverage is limited. Seismic data offer the possibility to provide additional constraints on the spatial distribution of facies. Seismic data on their own do not provide the complete solution, so a thorough integration of seismic, well and geological input, and any other available information, is required to reduce uncertainty and produce meaningful and predictive models. This has three serious implications for facies model building. Firstly, the seismic, well and geological constraints must be applied simultaneously to ensure a consistent and unbiased integration of all data. Secondly, the seismic and reservoir properties must be related through a predictive rock physics model that should be established through analysis of well log data and include facies-dependent depth trends. Thirdly, the facies definition must be meaningful in all domains: elastic, reservoir and geological. Naturally, the facies should also be identifiable from petrophysical well log data to ensure that wells can be used to constrain the models. Bayesian stochastic inversion provides a framework that is well suited to achieve all these goals.

Introduction

Reading (1996) defined facies in two ways: a facies is a body of rock with specified characteristics; and a facies should ideally be a distinctive rock that forms under certain conditions of sedimentation, reflecting a particular process or environment. These two definitions highlight why, when building static and dynamic models of reservoirs, it is important to include facies modelling as a critical part of the process. The distribution of reservoir properties such as porosity, permeability, and clay content, including connectivity and degree of heterogeneity, that define the static and dynamic characteristics depends on the distribution of facies, and the distribution of facies is controlled to a large extent by geology or geological processes. Therefore, geological insight should be used to construct and constrain models of facies distribution, which in turn controls to a significant degree the distribution of reservoir properties. Reservoir models thus derived are more likely to be geologically realistic, certainly compared to a purely geostatistical distribution or other trend-guided interpolation of the same properties.

However, geological knowledge is often not sufficient to ensure that the models are representative of the particular reservoirs under study, particularly if well coverage is limited. Seismic data, which are often present over the entire field, provide a means to constrain the property models to some degree through rock physics relationships between the desired reservoir properties and the elastic properties of the rocks and fluids. Equally, seismic data on their own cannot produce reservoir models at the detail required that are consistent with the geology. It is only through the integration of geological knowledge with seismic data that physically realistic models of the reservoirs under study can be generated.

There are a number of ways in which seismic data can be used to help build facies models as a means to constructing static and dynamic models, though few of them use facies as a means to constrain the property distributions. For example, it is common practice to use seismic attributes, including the results of deterministic seismic inversion, as trends to guide the facies population within models and then populate the facies models with reservoir properties (e.g., Dubrule, 2003; Nivlet et al., 2005; Doyen, 2007; Michelena et al., 2009). Such two-step approaches have been applied successfully in many fields over the years, but technical shortcomings have been documented (e.g., van Riel et al., 2005) that can lead to erroneous conclusions regarding connectivity and uncertainty caused by the difference of scale and support in using a low resolution constraint to generate a highly detailed model.

Another common approach is to use geostatistical inversion to populate models with properties which are then

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When reservoir models are built for static and dynamic modelling, it is desirable and often necessary for these models to have certain characteristics and honour certain constraints. Fundamentally, the models must provide accurate estimates of volumetrics and provide accurate history matches, if production has begun, or otherwise provide accurate predictions on the optimal development scenarios. Although this is simple in principle, it is a lofty goal in practice. Perhaps a more immediately attainable and realistic goal is to generate models that find acceptance for use by the geologist and reservoir engineer. This means that, for a start, the models must be geologically reasonable. One criterion that geologists would use to assess the realism is to look at the distribution, size, shape, and association of facies or groups of facies. Thus facies models must be built if acceptable reservoir models are to be generated. There are other reasons why this should be done, which we will come to later.

A range of tools and applications exist to allow geologists to build realistic facies models. However, there are limited applications that allow these models to be constrained tightly by seismic data. Most tools will allow the models to be driven by the degree of correlation between the facies distributions and one or more seismic attributes, but since the seismic data normally have lower resolution than the desired vertical detail of the models, there is a tendency, even in the best of cases, for such models to be unrealistically smooth and therefore not suitable for dynamic modelling. In the worst of cases, the facies and property distributions have little or no correlation with the seismic data. The concept of closing the loop, where synthetic seismic data are created from existing reservoir models for comparison with actual seismic, has put this lack of correlation into sharp focus (e.g., EAGE/SPE, 2011). However, there is currently little published work to clearly demonstrate that building a reservoir model tightly constrained to seismic data inevitably leads to a better dynamic model. If the seismic data cannot resolve the detailed flow heterogeneity and have no physical relationship with the flow properties, such as relative permeability, then the match to the seismic data from the point of view of reservoir property modelling is potentially of limited relevance. If the model gives a good history match but does not honour the seismic data, there is little reason why the reservoir engineer should care. Anecdotal evidence suggests that this lack of concern is quite a prevalent attitude within parts of the industry at the moment. On the other hand, if the upscaled reservoir model does not match the seismic data, one would wonder how accurate predictions of future production are going to be, even if the current history match is good. With the continued improvement in our understanding of rock physics, which describes the link between seismic and facies-dependent rock properties, and in the quality and bandwidth of seismic data, a model tightly constrained to seismic data should provide at least one of several scenarios for static and dynamic modelling.

The issues raised suggest that a number of criteria need to be fulfilled in order for reservoir models to be useful. Firstly, the models should be constructed in depth and consist of facies populated with reservoir properties needed for static and dynamic modelling. Modelling in depth is important to ensure that the well data are honoured in depth. If modelling is carried out in time and honours the well data in time, it can be very difficult to ensure that after time to depth conversion the models also honour the wells in depth to the required detail, typically less than 1 m, especially if deviated wells are present. On the other hand, if modelled in depth, the depth to time conversion to honour the seismic data only has to be as accurate as the resolution of the data, typically several metres. Secondly, the models should at a minimum also honour the following:

- Structural framework of the reservoir as interpreted from a geological and sedimentological analysis of the reservoir
- Well log data in terms of facies, elastic and reservoir properties appropriately upscaled to the detail required of the model
- Seismic data including variations in signal to noise and variations in frequency content that realistically capture spatial differences in data quality
- Petrophysical relationships between reservoir properties, such as porosity, permeability, and volume of clay
- Facies-dependent rock physics relationships between elastic and reservoir properties
- Facies-dependent depth trends such as compaction, pressure or geological trends
- Facies-dependent saturation height functions
- Geological expectations for zonal facies distributions and facies ordering rules
- Expected heterogeneity between facies as well as within facies
These criteria suggest a procedure whereby a starting model is generated that conforms to all the criteria except the seismic data; the elastic properties are then converted to time and used to generate synthetic seismic volumes. The match to the measured seismic is then evaluated, and the resulting residuals are used to guide the update of the model whilst continuously ensuring adherence to all other criteria. Iteration would continue until the desired match to the seismic data is obtained. This procedure could describe stochastic inversion, where the spatial distribution of facies and properties are controlled by geostatistical relationships as well as by the seismic data through an iterative process that seeks to reduce an objective function which includes the seismic misfit. There are many different types of stochastic inversion, but not all of them are capable of addressing all the criteria that have been outlined above. Importantly, not all are able to solve for facies and properties simultaneously combined with the seismic inversion. Many solve for properties with seismic inversion and subsequently assign facies in a secondary step. Clearly, if the facies are only assigned in a post-inversion step, no matter how sophisticated this step might be, it is then impossible to:

- Include different property trends (e.g., compaction trends) per facies
- Use different rock physics models per facies
- Drive facies distribution jointly between seismic and prior facies probability trends
- Have different degrees of heterogeneity per facies
- Assign facies-dependent saturation height functions that are consistent with the seismic data
- Include sharp boundaries in the properties (e.g., the sharp change in effective porosity when going from sand to shale) that are consistent with the seismic data, the rock physics, and the implied geostatistical smoothness constraints

If facies are interpreted from seismic inversion results instead of being inverted for directly, a significant amount of integration, consistency, and control over the characteristics of the reservoir model is lost. In a worst case, if the degree of heterogeneity within facies and between facies is not realistic, then the models will not be appropriate for dynamic modelling.

In the next section, a scheme is presented that addresses all the criteria, including solving for facies and reservoir properties simultaneously with seismic inversion. Before that, we need to discuss an additional issue that springs out of the need to solve for facies and properties simultaneously, which is the importance of the definition of the facies to be used in the modelling. If the distribution of the facies is to be partially driven by the seismic data, then the facies must have a reasonable degree of separation in the elastic domain. The facies must also have a geological meaning, to allow for geological constraints to be applied in terms of prior probability trends and to allow for the imposition of geological realism.

When the models are to be used for dynamic simulation, the facies must separate different dynamic properties such as different porosity-permeability relationships and regions of different flow heterogeneity. The facies should also be identifiable from well logs so that the wells can be used as constraints in the models. These requirements usually result in a different definition of facies than used in conventional geological modelling.

**Generating realistic and consistent reservoir models**

The approach advocated here for building reservoir models that honour all measured data and multidisciplinary constraints starts with building a model of facies populated with static and dynamic properties in depth constrained by geological information and beliefs. Functional relationships are then used to generate engineering properties within each facies and rock physics models are applied to these to generate elastic properties. The elastic properties are converted to the time domain and convolved with the appropriate wavelets to produce synthetic seismic data which are then compared to the measured seismic data to calculate residuals. The magnitude of the residuals is utilized along with all other information to update the facies and property model. The process continues until all data and constraints are honoured to the desired degree, thus ensuring the consistency of the resulting model with all available information. This approach is summarized in the workflow diagram illustrated in Figure 1, the details of which are delved into hereafter.

**Preparing the structural model, upscaling logs and defining facies**

The first step in this workflow requires building a 3D structural model in depth using horizons and faults picked in time and converted to depth using a velocity model derived from seismic velocities and calibrated to the well logs. A variety of depth models could be used to explore the impact of uncertainty in this velocity model. The zones within the structural model are defined to delimit intervals of differing geological, engineering, and geostatistical characteristics. Within each of the zones defined by the structural model, micro-layering is defined at the fine scale at which the model is to be built and aligned to represent the deposition of the rocks.

Next, the properties in the wells are upscaled appropriately to the micro-layering of the stratigraphic model. For example, the elastic logs are upscaled within each stratigraphic sample by applying Backus averaging to the logged values.

The facies are now defined based on the upscaled logs. The facies definition is a key factor, which has a great impact on the successful integration of all the data. It is, therefore, critical that the definition be made in close collaboration between the geophysicist, petrophysicist, rock physicist, geologist, and engineer. An illustration of such preparatory steps is given in Figure 2.
Including geological constraints

As emphasized throughout this paper, it is paramount to include geological constraints in any process that intends to use seismic data for modelling reservoir properties. Firstly, it is necessary for the simulation of facies to set a prior expectation of the facies distribution. This can be as simple as assigning a gross probability to each facies in a particular geological zone or as detailed as assigning a different probability for each facies at each sample throughout the model. Such information can, for instance, be extracted from net to gross maps available from a geological analysis such as depth to channel bottom (Figure 3a), from the amalgamation of available facies logs that have been intersected along the stratigraphic micro-layering of the model (Figure 3b) or from any volume-based interpretation. The point is that seismic data are clearly unable to resolve some of the vertical detail at which the model is constructed, yet it is important that the distribution of facies is acceptable to the geologist and engineer. For example, a sand that is 1 m thick may not have a noticeable impact on the seismic data, but if it is highly permeable it may have a profound impact on the dynamic properties of the model and thus must be captured during the inversion workflow.

Apart from the prior facies probability trends, it may be important to control the distribution of facies in other ways. It may be that facies are best represented in a multi-level fashion as in the example shown in Figure 3c, where the sands in a sand-silt-shale environment are further subdivided into three types of sands of various quality that depend on key traits of the local geological environment. In some geological settings it may be desirable to impose an ordering of the sands and isolate the low from the high quality as illustrated in Figure 3c. The flexibility of a mutually thresholded Gaussian approach, for example, easily allows different constraints to be placed on different levels, making it possible to model effects such as sands that are continuous across multiple fluid contacts, with the distribution of each type of sand being driven by a different probability trend. Naturally, it may be desirable in some cases to opt for other facies simulation algorithms such as...
the increasingly popular multipoint geostatistical techniques. Whichever the algorithm, the requirement is for it to be compatible with the stochastic updates and perturbations required by the framework of the workflow advocated herein.

In most cases, there are also geological constraints to be imposed on the petrophysical properties and, critically, these will differ significantly in each facies (Avseth et al., 2005). Petrophysical properties such as porosity and volume of clay that are required for determining the elastic properties through the rock physics model and for building the static model are analysed for any depth or stratigraphic trends that would not be resolved by the band-limited seismic data. Any trends can be removed from the upscaled well log data to leave what we will term residuals. For example, the porosity may vary systematically but differently for each defined facies with depth below seafloor even within one geological zone. If trends have been found then they need to be interpolated across the entire volume. Interpolation can be done deterministically or geostatistically to take uncertainty into account (Sams and Saussus, 2010).

**Modelling geostatistical characteristics of facies and properties**

The residuals that remain in the well logs after trend removal will be simulated during the modelling. In order to allow this, the expected distribution of the property residuals and the correlation with the other property residuals needs to be derived. For example, the porosity residuals and volume of clay residuals are plotted as histograms and cross-plots. The correlation between all properties is found and the histograms are modelled with either parametric or non-parametric distributions to provide multidimensional probability density functions.

The spatial correlations of the residuals and of facies are set using geostatistical constraints such as variograms or multipoint statistics. In Figure 4 the constraints applied are of the mutually thresholded Gaussian variogram form for the facies, possibly truncated if specific positional ordering is desired, and of the conventional two-point nature for the continuous properties within each facies. Whatever geostatistical smoothness constraint is used, it must be able to reflect
the different degrees of heterogeneity that exist between and within facies. As is always the case, assigning the suitable level of smoothness may not be straightforward, but it must capture the proper level of heterogeneity. Well log data and analogues provide some control, but several choices may be taken forward to acknowledge the uncertainty. It must also be noted that in the particular implementation of stochastic inversion used in the examples present here, the geostatistical smoothness constraints are a prior expectation, just as for the facies distributions described in the previous section, and thus act as a guide such that they do not override the requirement to honour the seismic data (Sams et al., 2011).

**Rock physics modelling and inversion**

We are now in a position to start the inversion described schematically in Figure 1. As indicated previously, there are potentially many stochastic inversion schemes that could be used to drive this workflow. We present one such scheme. The facies and property distributions detailed in the previous sections are used to create a posterior probability density function through Bayesian inference. This probability density function is then sampled using a Markov Chain Monte Carlo algorithm in order to produce a detailed model proposal, in depth, of facies and reservoir properties such as porosity and clay content. As depicted in Figure 5a, this model proposal can then be used to internally compute other petrophysical properties like permeability, using different functional expressions for each facies, and similarly saturation, which in the case shown is computed using facies-dependent saturation height functions that use all of the previous properties as input. The petrophysical properties are then converted internally to elastic properties through each of the facies-dependent rock physics relationships (Figure 5b), after which a velocity model is applied to convert the elastic properties from the depth to the time domain. Obviously, the rock physics modelling plays a central role in such approaches and so care should be taken to ensure the models reflect the geological characteristics of the reservoir being inverted and that these are able to accurately reproduce the key features of the measured petrophysical logs.

The elastic properties are subsequently passed through the desired convolutional model, usually with either Knott-Zoeppritz or Aki-Richards equations governing the reflection coefficients, with either constant or spatially varying wavelets in order to generate volumes of synthetic seismic data (Figure 6). These are compared to the measured seismic data to compute residual volumes whose contents are used in combination with the input data to update the conditional probability density function, which can then be sampled to produce an updated model proposal. A noteworthy point is
that in the particular stochastic inversion scheme used for the examples presented here, each model proposal contains a full volume of all properties, not just a few samples or traces. That is, the facies and reservoir properties at all points in the volume are updated simultaneously, removing any bias of a starting point or lengthy sub-iterations to remove such bias. The process iterates until the underlying algorithm reaches equilibrium or convergence.

An illustration of the impact each update has on the facies model throughout a single run of this process is shown in Figure 7. Note how the correlation between the seismic data and synthetic data resulting from the proposed model updates steadily increases as the run proceeds, while honouring the desired facies and property distributions each step of the way, thus ensuring the final reservoir model benefits from the proper integration of all constraints.

The final output of a single run of the workflow includes volumes of facies, petrophysical (e.g., volume of clay and porosity), and engineering properties (e.g., water saturation, permeability) in depth, as illustrated in Figure 8. All of these volumes are consistent with one another and reflect the desired heterogeneity and geological realism. By generating multiple realizations, it is also possible to get quantitative estimates of the uncertainties for each of the desired properties to aid in decision making.

Discussion
The goal of this paper was to present a detailed recipe for highly flexible and powerful approach to building reservoir models that will be acceptable to engineers and geologists whilst satisfying the constraints imposed by the seismic data. This workflow has been illustrated with examples from actual projects. The value added from following such an approach in practice is presented elsewhere. Such studies have demonstrated that the application of this sort of approach leads to successful predictions of volumetrics as confirmed by wells drilled after the inversion was completed (e.g., Filippova et al., 2011), geologically realistic distribution of facies below seismic resolution (e.g., Sams et al., 2010) and accurate detection and spatial delineation of thin reservoir beds verified by cross validation (Merletti et al., 2010), just to cite a few.

Caveats
Prior to running a detailed stochastic inversion it is important to run a deterministic inversion followed by a Bayesian facies probability analysis. There are a number of reasons to do so. Firstly, the results should look like a low resolution version of what is expected from the stochastic inversion at least in terms of facies and elastic properties distributions. If not, then perhaps the seismic data do not sufficiently constrain the facies distribution and the facies need to be redefined. Secondly, the results can be used to refine well ties, wavelets, and horizon interpretation. Thirdly, it is easier to assess the seismic data for special requirements such as laterally varying wavelets or signal to noise.

In order to ensure that the derived models are geologically meaningful and useful the results must be assessed and
the input parameters, such as the prior facies probabilities, adjusted. Clearly this cannot be achieved through software optimization alone but requires expert consultation with a geologist and reservoir engineer. This will usually mean that many models are generated on the way to a final set of models. With the use of readily available workstations, a single realization of facies, elastic, petrophysical and engineering properties covering hundreds of thousands of seismic trace locations and a depth window of 300 m can be generated at the metre scale in a few hours, making the application of such sophisticated workflows quite appealing.

Conclusions

Realistic facies models are essential to ensure that static and dynamic reservoir models observe the correct distribution, connectivity, and heterogeneity of key properties. Building realistic facies models requires integration of diverse data, information and beliefs from all relevant domains, notably geology, geophysics, rock physics, engineering, and petrophysics. Such a level of integration, particularly when dealing with data measured at different scales, is optimally achieved through a workflow that is driven by stochastic inversion within a Bayesian context that allows solving for facies and reservoir properties simultaneously. The key to the success of this approach lies in its ability to integrate various constraints while preserving the geological realism of the reservoir model properties and without degrading its fit to various measured data.

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References


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