A Pragmatic Approach to Simulator-to-Seismic Modelling for 4D Seismic Interpretation

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Abstract

Here, I develop a method for modelling 4D seismic data from simulations of fluid flow and pressure evolution in hydrocarbon reservoirs during production. To achieve this objective, previous work is firstly critically analysed to identify key features, limitations and requirements. Consideration is given to grid geometry, spatial sampling, a petro-elastic model, and a modelling algorithm. A practical method is employed to link the petrophysical domain to that of the simulation domain. Central to this connection is the choice of an appropriate common ‘porosity’ measure. Another key study is the calibration of the rock stress-sensitivity, which utilises the seismic response observed near water injectors. For the seismic modelling, the 1D convolution and finite difference are contrasted. The former (faster approach) is found to be as accurate as the latter when an acquisition-controlled smoothing operator is included. Sim2seis modelling is applied initially to a field simulation model to highlight the role of pressure and saturation in determining the seismic response. It is then applied to two North Sea case studies, revealing the benefits in assessing vertical and lateral connectivity, and tracking fluid-fluid contacts using seismic amplitude change and time-shifts. The strong role of the static model is also revealed from this application. Overall, my work has shown that well-calibrated sim2seis modelling can provide quantitative interpretation of 4D seismic data, and facilitate update of the simulation model on which forward predictions of field performance and economics are based.
To my brother, Navid
Acknowledgments

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\(^1\) David H. Johnston (ExxonMobil), Making a difference with 4D: Practical applications of time-lapse seismic data, SEG Distinguished Instructor Short Courses (DISC), 2013.

\(^2\) Olav I. Barkved (BP), Seismic surveillance for reservoir delivery, EAGE Education Tour 6, 2012.
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Degree Sought | PhD, RESERVOIR GEOPHYSICS

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2) where appropriate, I have made acknowledgement of the work of others and have made reference to work carried out in collaboration with other persons
3) the thesis is the correct version of the thesis for submission and is the same version as any electronic versions submitted*.
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The highest activity a human being can attain is learning for understanding, because to understand is to be free.

Baruch Spinoza (1632-1677)
For want of a nail the shoe was lost.
For want of a shoe the horse was lost.
For want of a horse the rider was lost.
For want of a rider the message was lost.
For want of a message the battle was lost.
For want of a battle the kingdom was lost.

And all for the want of a horseshoe nail.

and the nail was the detail ...
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CHAPTER 1

Simulator to Seismic Modelling for
Reservoir Surveillance and Monitoring
1.1 4D seismic and simulation model in reservoir management

Reservoir management is an integrated dynamic practice that ‘relies on the utilisation of available resources (i.e., human, technological and financial) to maximize profits/profitability index from a reservoir by optimising recovery while minimising capital investments and operating expenses’ (Satter and Thakur 1994). The essential elements of a reservoir management plan are shown in Figure 1.1; once the management goals are set, the initial development plan will be designed and implemented accordingly. Throughout the implementation phase, constant monitoring and surveillance of the reservoir performance is required in order to evaluate whether the reservoir performance is conforming to the management plan. The monitoring and surveillance programme will depend upon the nature of the project. Prior to the popularity of 4D seismic technology, conventional monitoring and surveillance tools were limited to the engineering solutions, including measuring the (1) oil, water and gas production, (2) gas and water injection, (3) static and flowing bottom-hole pressure, (4) production and injection tests, (5) injection and production profiles (Satter and Thakur 1994).

Figure 1.1 The key elements of the reservoir management workflow (Satter and Thakur 1994).
Chapter 1: Simulator to Seismic Modelling for Reservoir Surveillance and Monitoring

Figure 1.2 Integration of the different elements of reservoir management (Satter and Thakur 1994). Among the different technologies, seismic (marked in red) is present throughout the lifecycle of the field. Since publication of this plot, more seismic-related tools have been developed, including quantitative reservoir geophysics analysis and, in particular, 4D seismic.

A successful reservoir management program requires full integration of the different elements of management, including people, technology, tools, and data (Figure 1.2). Among the different technologies that contribute to reservoir management, seismic is one of the technologies that is present throughout the lifecycle of the field (Table 1.1).

Satter and Thakur (1994) anticipated that geophysicists will be involved throughout the life of the reservoir beyond the exploration, appraisal and development phases toward production phase. The paradigm perceived in their book about the future role of geoscience in reservoir management has become reality; since publication of their book, in the past 20 years 4D seismic has continuously gained a significant recognition as a surveillance tool. Following the 1990’s successful implementation of 4D seismic in the North Sea (Draugen 1998; Gullfaks 1996; Ekofisk 1995; Valhall 2002), 4D seismic technology (acquisition, processing, and interpretation) and the breadth of its application has expanded drastically. The evolution of the 4D seismic in the past three
**Exploration/Appraisal** ➔ **Define and evaluate the reservoir**

- Characterise the trap
- Determine structural nature
- Structural closure
- Fluid-flow boundaries
- Lateral/vertical extent of the hydrocarbon
- Reservoir thickness distribution
- Volume

**Development** ➔ **Depletion planning and well placement**

- Reservoir model construction
- Property distribution
- Seismic stratigraphy
  - Depositional pattern
  - Facies distribution
- Fluid contacts
- Lithology and porosity
- Fracture characterisation

**Production** ➔ **Maximise profitability**

- 4D seismic
  - Primary surveillance tool
  - Increase reserve/recovery
  - Optimise field development plan
  - Maximise efficiency in EOR

**Table 1.1** The role of seismic technology at different stages of the life of the field cycle (Johnston 2013).

<table>
<thead>
<tr>
<th>Seismic Survey</th>
<th>Focus</th>
<th>Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permanent Onshore 1980-1990</td>
<td>Complex combustion process</td>
<td>EOR performance</td>
</tr>
<tr>
<td>Legacy Marine 1990-2000</td>
<td>Identification of barriers/baffles</td>
<td>Infill wells</td>
</tr>
<tr>
<td></td>
<td>Fluid contacts</td>
<td></td>
</tr>
<tr>
<td>Dedicated/Permanent Marine 2000</td>
<td>Pressure and saturation estimate</td>
<td>Water management</td>
</tr>
<tr>
<td></td>
<td>Bypassed oil</td>
<td>Reservoir management</td>
</tr>
<tr>
<td>Permanent/Passive Marine/onshore?</td>
<td>Frequent survey</td>
<td>Well performance</td>
</tr>
<tr>
<td></td>
<td>Well focus</td>
<td>Base management</td>
</tr>
<tr>
<td></td>
<td>Outside reservoir</td>
<td>Stress change</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Drill-cutting re-injection</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Out of zone injection</td>
</tr>
</tbody>
</table>

**Table 1.2** The evolution of 4D seismic technology in the past three decades (Barkved 2012).
Corporate impact

- Cash flow prediction
  - Need economic forecast of hydrocarbon price

Reservoir management

- Coordinate reservoir management activities
- Evaluate project performance
  - Interpret/understand reservoir behaviour
- Model sensitivity to estimated data
  - Determine need for additional data
- Estimate project life
- Predict recovery versus time
- Compare different recovery process
- Plan development or operational change
- Select and optimize project design
  - Maximise economic recovery

Table 1.3 The benefits of the simulation model (Fanchi 2001).

decades is summarised in Table 1.2. Nowadays, 4D seismic technology is a primary surveillance tool that can be used to help increase reserves and recovery, to optimise the field-development plan, and to maximise efficiency in enhanced oil recovery operations (Johnston 2013).

Another important technology in reservoir management is the fluid-flow simulation model. There are many reasons to run simulation models. Perhaps the most important reason from a commercial perspective is the ability to generate economic forecasts (Fanchi 2001). Simulation provides a production profile, and the combination of the production profile and price forecast gives an estimate of future cash flow. However, simulation models also provide the most sophisticated methodology available to target the primary objectives of reservoir management – determining the optimum conditions needed to maximise the economic recovery of hydrocarbons. The forecasts from simulation models can play a crucial role in establishing the reservoir management plan. Table 1.3 lists how reservoir management benefits from simulation models. The key problem is the reliability of the predictions of simulation models; it is thus vital to capture the heterogeneities that control the reservoir performance and to narrow the range of uncertainties in the model.
1.1.1 4D seismic data and the simulation model in synergy

In the previous section, the importance of both 4D seismic data and simulation models in reservoir management is has been explained. These two technologies provide tools with different timelines in reservoir management. The simulation models are intended to provide a long-term perspective on the future performance of the reservoir. On the other hand, each 4D seismic survey – as a monitoring and surveillance tool – helps to evaluate the reservoir management decisions that have been implemented to date, and revise future plans. 4D seismic data provides invaluable information about reservoir performance and reservoir heterogeneity; this information can be used to assess and restrict the existing uncertainties in the simulation model. During the field life of cycle, different revisions of the reservoir model are generated and the information from earlier 4D surveys is essential in conditioning the reservoir models. Therefore, bringing the 4D seismic data and simulation model together helps to improve the reliability of the simulation model forecasts.

Figure 1.3 shows the different processes related to the 4D seismic technology throughout the field lifecycle. At the early stages of discovery and

![Figure 1.3 4D seismic processes at different stages of field lifecycle. Sim2seis (labelled as s2s) is applicable for 4D feasibility studies and model-based 4D interpretation (Johnston 2013).]
appraisal, preliminary 4D screening studies should be performed to study the 4D signature of the reservoir, considering the reservoir drive mechanism, fluid properties and parameters that represent the average reservoir rock and. During the development phase, more advanced 4D seismic feasibility studies are performed. In addition to 1D well-based modelling, a simulation model can be used to model the expected magnitude of the 4D signature, and make predictions of the characteristics of repeat surveys. During the production phase, if the interpretation of the initially acquired 4D seismic data proves to be a successful monitoring tool, the plan regarding the acquisition of future repeat survey(s) will be reviewed. As will be covered in Section 1.3, 4D seismic data interpretation can be performed in conjunction with the simulation model, and more frequent repeat surveys give the opportunity to continuously assess the performance of the simulation model against the observations based on 4D seismic data.

1.2 Simulator to seismic modelling (sim2seis) – an introduction

As reflected in its name, simulator to seismic modelling bridges the gap between the fluid-flow simulation model and the seismic, and opens a new platform for taking 4D seismic data into the core of the reservoir surveillance and management plan. Simulator to seismic modelling (hereafter sim2seis) is a process to create the synthetic seismic response from a simulator during different stages of production.

In addition to pressure and saturation changes, stress and strain variations within (and outside) the reservoir are inevitable effects of production. Geomechanical models coupled with the simulation models have been developed to characterise the geomechanical effects of production (Hatchell and Bourne 2005; Staples 2007). However, in this research attention is restricted to reservoirs with minimal geomechanical effects, and hence geomechanical models are not discussed in this thesis.
The basic steps of sim2seis workflow are as follows:

1. Run the simulation model (black-oil or compositional) and extract the static ($\phi$, $V_{\text{state}}$, lithofacies index, etc.) and the dynamic properties (pore pressure and saturation for different fluid phases, solution gas-oil-ratio, oil formation volume factor, etc.) from the simulation model at the selected time-steps.

2. Convert the static and dynamic properties into elastic properties ($V_p$, $V_s$, and density) using a petro-elastic model (PEM). The underlying equations and parameters in PEM should be calibrated according to the specific field of study. This calibration ensures realistic values for changes in in-situ elastic parameters due to changes in saturation and pressure.

3. To be able to calculate the synthetic seismic response, elastic properties should also be assigned to the overburden and underburden.

4. Choose a seismic modelling approach and an appropriate wavelet to generate the pre/post stack synthetic seismic.

5. Assessment of the 4D signal in the presence of non-repeatable noise might also be required in some applications.

6. Interpret the 4D signals by generating attributes that can be tied to the production data.

As will be laid out throughout this thesis, sim2seis is a multi-disciplinary tool which requires data integration from petrophysics, engineering, and geophysics disciplines. The workflow, as outlined above, represents a very simplistic description of the process, but when it comes to its implementation in practice, it takes a great deal of attention to detail to overcome the various hurdles at each step.

1.2.1 Sim2seis applications

During the field lifecycle (Figure 1.3), sim2seis can be used for two main purposes: feasibility studies at the development phase and 4D seismic data interpretations during the production phase.
For 4D seismic to be a part of the reservoir surveillance plan, one cannot rely solely on the outcome of the preliminary 4D screening. As pointed out by Johnston (2013), 4D screening studies depend on the average reservoir properties, and feasibility studies are required to assess the 4D signal over the full range of variations in the rock properties, fluid saturation, and pressure. Typically, well-log based 4D seismic modelling is performed to cover these aspects. However, this modelling can be biased if the log data is not representative of the true variability of the reservoir properties. Moreover, well-based modelling does not offer enough information to address lateral sweep interpretation and the optimum timing of repeat surveys in the presence of non-repeatable noise. Sim2seis provides a powerful tool to examine these features of feasibility studies. However, the main focus of interest in this thesis is to construct a pragmatic sim2seis workflow to address the second application of sim2seis during the production phase – the use of sim2seis in 4D seismic data interpretation. Compared to the feasibility studies, the second application requires a more detailed insight into the connection between the simulation model and the observed 4D seismic data.

1.3 4D seismic data interpretation

As shown in Figure 1.4, 4D seismic data interpretation can be performed at different successive levels. By moving towards more sophisticated levels, the simulation model becomes an integral element of the analysis and more integration between the engineering and seismic disciplines is required. Although reservoir management potentially benefits from bringing the 4D seismic data and the simulation model together, more sophisticated multi-disciplinary approaches bring about more complications. It should therefore be noted that the higher levels of the 4D interpretation should not substitute the lower ones; i.e. it is absolutely essential that by starting from the first level and moving sequentially to higher levels, the complications and issues related to each element of every level can be recognised and remedied. In the following section, the details of such complexities at each level of 4D interpretation are covered. Additionally, the role of sim2seis in 4D interpretation is explained and the
• 4D analysis with production data (qualitative)
• 4D analysis with simulation model (qualitative)
• 4D analysis with simulator to seismic modelling (qualitative)
• 4D analysis with simulator to seismic modelling (quantitative)
• Seismic history matching (quantitative)

Figure 1.4 Different levels of 4D seismic data interpretation.

concept of closing the loop is outlined. It is intended here to provide the perspective on how sim2seis as a high-level interpretation tool fits into the bigger picture of reservoir surveillance and monitoring, and ultimately into the reservoir management plan.

1.3.1 4D seismic data interpretation in conjunction with the production data

In comparison to 3D seismic data interpretation, where the seismic data are tied to the well data, in 4D seismic data interpretation the production data stand as the ground truth. The term production data commonly refers to the (static/flowing) bottom-hole pressure measurements and the measured cumulative volumes of injected and produced fluids. The cornerstone of any 4D seismic data interpretation is to register a sensible 4D signal that conforms to the production data. In other words, it is aimed to establish a one-to-one relationship between the production data and the 4D seismic data that represents hardening/softening signals. Generating such 4D attributes is a challenge and typically requires detailed scrutiny of the seismic data during acquisition, processing, and interpretation. Quite often the horizons used for mapping need to be revised; the wavelet artefacts, such as tuning and side-lobe effects should be considered; the producing and non-producing (active/inactive) intervals (e.g. in the case of stacked reservoirs) should be distinguished at the mapping stage. Generally the reservoir heterogeneity is underestimated and the assumption of the reservoir being a layer-cake model does not suffice; hence simply generating conformable horizons that are between the top and base of
the reservoir often fails to extract coherent 4D maps within the reservoir sub-intervals. It is therefore, it is essential to take into account the internal heterogeneous architecture of the reservoir, which typically involves interpreting the horizons that confine the active/inactive geobodies (e.g. channel boundaries or internal shale layers). Seismic inversion can be used to address some of these challenges, such as by reducing the wavelet artefacts and by providing a better understanding of the reservoir geometry and architecture.

Depending on the nature of the reservoir drive mechanism and the thickness of the reservoir, different choices of seismic attributes can be made for 4D signal registration. For example, for bottom water drive, looking at the vertical sections is more convenient for inspecting the fluid contact movements, whereas for edge water drive, mapping shows the extent of the lateral sweep. Generally, two approaches for mapping can be taken: either by differencing the attribute maps from the baseline and monitor surveys or by generating a map from the difference between seismic cubes. When using the root-mean-square (RMS) attribute, the former approach is preferred, as it distinguishes between the hardening/softening signals with different polarities, whereas in the latter approach, the 4D signal represents the resultant of both these effects. It should be noted that the time-shifts between the different 4D seismic cubes should be removed before differencing; this is not of concern in the first approach where the maps are subtracted and not the seismic traces.

Once the 4D signal is tied successfully to the production data, the inter-well 4D interpretations are fed to the reservoir surveillance and management plan by optimising well locations, managing water and gas sweep, revising reserve estimation, and optimising well completions (Johnston 2013). Since the early implementation of the 4D seismic technology, numerous published examples have described successful well-planning and the avoidance of dry-holes based on the basic, yet fundamental 4D seismic data interpretation in conjunction with the production data (Gouveia et al. 2004). This approach remains the key technique in 4D seismic data analyses, and to date is a well-established tool in reservoir surveillance and monitoring.
**Figure 1.5** Different domains of comparison between the seismic data and the simulation model. The horizontal arrows (solid line) show the domains for which the loop between seismic and simulator can be closed. The tilted arrows (dashed line) show the possible cross-domain comparisons. The darker arrows show the more popular domains of comparison.

### 1.3.2 Model-based 4D seismic data interpretation and closing the loop

Incorporating two approaches to reservoir surveillance and monitoring – the simulation model and 4D seismic data – is beneficial in both updating the simulation model and in resolving the ambiguities in the interpretation of the 4D signal away from the wells. Bridging these two disciplines can be performed in different domains. Figure 1.5 shows the domains in which 4D seismic data and the simulation model can be assessed against each other. The simulator to seismic modelling technique is used to generate variations in elastic parameters and also synthetic 4D seismic attributes. Cross-domain comparisons are very common in model-based interpretations, where the observed 4D seismic attributes are compared with the saturation/pressure maps from the simulation model or with the modelled impedance from sim2seis. Hypothetically, it is best to perform the comparison in the same domain; a task that involves a great deal of meticulous effort. Updating the simulation model by bringing the simulation model and the 3D/4D seismic into similar domains is also referred to as closing the loop between the two disciplines.
4D seismic data interpretation in conjunction with the simulation model

In theory, the boundaries of the 4D signal anomalies could potentially be the flood-fronts, the barriers/baffles, the compartment borders, or the edges between active/inactive units; all of which can be cross-checked by observing how the pressure and saturation evolve in the simulation model. The lateral/vertical connectivity between flow units in the simulation model can also be validated from 4D seismic data (MacBeth and Al-Maskeri 2006; Thore et al. 2011). Fluid contact movements in the presence of a number of horizontal wells can be quite irregular. Simulation models simulate the pressure gradients around horizontal wells, which result in the coning of the contacts, and this information can potentially be used to interpret the contacts from seismic data or to update the simulation model.

The details mentioned above are some of the intriguing aspects of 4D seismic data interpretation alongside the simulation model; however, prior to engaging the information from both sides some questions should be addressed. 'Is the simulation model history-matched?' Although matching to the history of production at well location does not guarantee the realistic behaviour of saturation and pressure away from the wells, history-matching does rule out the models that are far from reality. 'How consistent is the geological model (hence the simulator) with the seismic?' A reservoir model that is built to be consistent with the 3D seismic data makes it easier to be tied to the 4D seismic data. 'How genuine is the 4D signal?' The non-repeatability analysis (e.g. Normalised Root Mean square (NRMS) analysis, Kragh and Christie 2002) can be helpful in identifying areas where the 4D signal might be less reliable. 4D mapping (as mentioned in Section 1.3.1) also needs to be checked.

4D seismic data interpretation and sim2seis

One of the uncertainties in cross-domain 4D seismic data interpretation occurs when the average pressure and saturation maps from the simulator are assessed against the 4D seismic maps. Simulation models are capable of providing very detailed vertical variations of pressures and saturations at the scale of the simulator grid. Although seismic data is not blind to those details, nonetheless,
they are represented as a low resolution, smooth, band-limited response. As well as the change in saturation and pressure values, the seismic response is influenced by the geometry (thickness) of such changes. A simple *averaging* of the properties from the simulation model does not reflect the way that seismic data represents such details. Closing the loop between the simulator and seismic using sim2seis gives the opportunity to transform those features into the band-limited seismic data, hence enabling us to perform a one-to-one assessment of the simulator versus the 4D data by generating the same attributes (4D amplitude or time-shift). Seismic attributes are influenced by the seismic wavelet, and sim2seis modelling allows recognition of the wavelet’s footprints over the 4D attributes.

In the cases where the production induced effects do not overlie each other, the interpretation of the 4D signal is straightforward. These cases are limited and include (1) injecting water into an aquifer where there is no fluid phase change and a pure pressure build-up can be recognised, (2) pressure depletion around a producer where no fluid phase change is observed, and (3) pressure build-up due to water/gas injection in a sealed compartment in areas where the saturation front has not yet reached to the boundaries of the compartment. However, in most cases the pressure and fluid-phase changes are coupled, and can thus either constructively or destructively interfere in the seismic domain. These cases include (1) water injection into an oil-bearing zone, where pressure build-up softens (decrease in P-impedance) the rock while oil being replaced by water hardens (increases P-impedance) the rock, (2) pressure depletion around producers and, potentially, gas breakout, which result in hardening and softening respectively (e.g. Schiehallion Field, West of Shetland), (3) pressure build-up due to gas injection for storage or disposal in an aquifer, where both pressure build-up and water being replaced by gas soften the rock (e.g. An Teallach Field, West of Shetland) and (4) pressure build-up due to gas injection into the oil-bearing zone, where both pressure build-up and oil being replaced by gas soften the rock (e.g. Girassol Field, offshore Angola). Clearly, the main question in these cases is the balance between the two effects, and whether the 4D seismic data can be used to discriminate between these coupled effects? Sim2seis analysis is an invaluable tool to address this question. It should be
noted that in these examples, the water influx is assumed to be mainly horizontal (edge-drive) and the analyses are therefore mainly map-based; when the water influx is vertical (bottom-drive), particularly in three-phase systems where the gas-oil contact and oil-water contact are moving simultaneously, the seismic vertical resolution can be an issue and 4D interpretation is more problematic. An example of such a situation is discussed in detail in Chapter 6.

**Seismic history matching**

In a reservoir management plan where the simulator is an integral part of the workflow, the predictive capability of the simulation model is an important feature. Throughout the field lifecycle, continuous assessment of the simulation model’s performance against the production data from wells decreases the uncertainties in the model and improves the forecast reliability of the simulator. *Production history matching* (or *history matching* in brief) is a mature technology put in place to facilitate this process. Although the match to the historical production data does not guarantee the success of future predictions, history matching rules out the model realisations that fail to simulate the production profile to date and hence decreases the uncertainty in future predictions. As stated by Fanchi (2001), ‘a fundamental concept of history matching is the concept of a *hierarchy of uncertainty*. The hierarchy of uncertainty is a ranking of model input data quality that is used to determine which data is the most and least reliable.’ The hierarchy of uncertainty is used to choose which parameters should be updated first. Clearly, another important criterion of ranking the parameters is the influence of the parameters on the

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Pressure match</th>
<th>Saturation match</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pore volume</td>
<td>$\Delta P/\Delta t$</td>
<td>*</td>
</tr>
<tr>
<td>Permeability thickness</td>
<td>$\Delta P/\Delta x$</td>
<td>$\Delta S/\Delta t$</td>
</tr>
<tr>
<td>Relative permeability</td>
<td>*</td>
<td>$\Delta S/\Delta t$ and $\Delta S/\Delta x$</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>*</td>
<td>Not used</td>
</tr>
<tr>
<td>Bubble point pressure</td>
<td>$\Delta P/\Delta t$</td>
<td>*</td>
</tr>
</tbody>
</table>

* Avoid changing if possible

**Table 1.4** The influence of key history matching parameters (Fanchi 2001).
reservoir performance. Table 1.4 summarises the key history matching parameters. As an inverse problem with multi-dimensional parameter space, an unwelcome inherent feature of the history matching process is the non-uniqueness of the solutions. Lack of constraints away from often sparsely distributed wells adds to the non-uniqueness of this workflow.

In the fields where 4D seismic has proven to be a successful monitoring technology, acquisition of more frequent repeat seismic surveys can be accommodated into the reservoir management plan. In this case, the high resolution 4D seismic data (compared to the well spacing) is very appealing for utilisation into the conventional (production) history matching process. The underlying motivation of this process is to use the 4D signal as a high resolution spatial constraint to guide the updating algorithm in the history matching workflow. This process is known as seismic history matching (SHM), where, in addition to the evaluation of the match quality to the well production data, the loop between the simulation model and the seismic is closed and the simulation model is assessed against the observed 4D data in the desired domain (Figure 1.6). To close the loop in the seismic domain, sim2seis should be used to generate the synthetic 4D response. Updating the simulation model can be achieved by adjusting the parameters in the simulation model either manually or by a semi-automated method. The automated (or semi-automated) approach is an iterative process where the misfit function is a combination of the match to the production data and the match to the 4D seismic data. The outcome of this workflow is a simulation model with a performance consistent with both the production data at the wells and the 4D seismic data. Satisfying both the production and 4D seismic data means that the quality of the match to production data in the SHM workflow might be lower, compared to a model that is only production history matched. Deciding on the relative weights for production data and 4D seismic data in the misfit function in SHM is case dependent. These weights vary subject to the reservoir production mechanism, the quality of the production and 4D seismic data, the success of the 4D seismic monitoring and the role of the production and 4D seismic data in reservoir management. In cases where the 4D seismic is key in the development of the field, a reservoir model with a poorer match to production data that conforms
to the 4D seismic data is preferred over a model that is matched only to the production history.

Figure 1.6 The seismic history matching (SHM) workflow. The black arrows show the conventional (production) history matching workflow. The misfit function in SHM is a combination of the match to the production data and the match to the 4D seismic data. Closing the loop and 4D data evaluation can be performed across different domains (adapted from Lumley and Behrens 1998).
Figure 1.7 Semi-quantitative application of sim2seis in manual model updating. The transmissibility across the baffle (marked in red) is studied. (a) observed 4D (2005-1991), and synthetic seismic responses for (b) sealing baffle, (c) strong baffle (800x), (d) moderate baffle (200x), (e) weak baffle (50x), (f) no baffle (1x). Based on these results, a strong or a moderate baffle is suggested; weak or open baffles fail to generate the observed the 4D signal in the south of the field (Helgerud et al. 2011).

1.4 Sim2seis challenges and the thesis outline

The previous sections have highlighted the importance of sim2seis in 4D seismic interpretation. It has been described how sim2seis contributes to the reservoir management plan by reducing the ambiguities in the 4D data interpretation and updating the reservoir model. Several applications of sim2seis in this regard are reported in the literature. Helgerud et al. (2011), in a semi-quantitative application of sim2seis in model updating in the Hoover Field in the Gulf of Mexico, generated synthetic 4D maps of the simulation model by varying the transmissibility across a baffle to match the 4D signal in the south of the field (Figure 1.7). In a quantitative approach based on sim2seis, van Gestel et al. (2011) applied seismic history matching workflow to Life of Field Seismic data (LoFS) at the Valhall Field, to update the reservoir model. Forty realisations of the simulation model, which were matched to the production data, were evaluated against the observed 4D seismic. Vertical permeability, fault transmissibility, and pore volume multipliers were varied to update the reservoir
models. A quality match factor (QMF) was designed to quantitatively compare the synthetic and observed 4D maps and rank the best models accordingly. The best and worst matches are shown in Figure 1.8.

In this thesis, it is not intended to use sim2seis as a tool, but to focus on a critical assessment of the existing algorithms behind this process, instead. Sim2seis appears to be a well-established technique; however, this thesis highlights those aspects that are overlooked in the literature in. It should be noted that providing a universal recipe that covers all aspects of the sim2seis workflow may not be practical, because the challenges in sim2seis are defined by the reservoir specific drive mechanism and reservoir heterogeneity and architecture, which are governed by the geological settings.

As mentioned earlier, sim2seis is a multi-disciplinary tool that brings petrophysics, geophysics and engineering disciplines together. In fact, an independent research project could be set up for every element of the sim2seis process. One of my main challenges and concerns in this piece of research was to keep the bigger picture of the sim2seis workflow in perspective. Becoming an expert petrophysicist, an expert geophysicist, and an expert engineer is not affordable in the time-frame of a PhD project; my aim was to integrate the relevant concepts from the different disciplines, while keeping the sim2seis
workflow as a whole was of paramount importance. What follows highlights the challenges in constructing a robust yet practical sim2seis, which form the areas of focus in my research.

1.4.1 The petro-elastic model

The petro-elastic model (PEM) is the cornerstone of sim2seis. For the purpose of this study, I will confine its application to clastics. PEM for clastics has been extensively investigated in the literature e.g. different fluid substitution (Biot, 1956; Geertsma and Smit, 1961; Gassmann, 1951; Brown and Korringa, 1975; Berryman and Milton, 1991; Ciz and Shapiro, 2007); and stress-sensitivity models (Hertz-Mindlin, 1949; Eberhart-Phillips, 1989; Khaksar et al., 1999; MacBeth, 2004; Shapiro and Troyan, 2002) are developed to capture the effect of saturation and pressure changes on the elastic parameters. However, cases that represent a model that combines both pressure and saturation effects and are applicable to heterogeneous sand/shale systems are limited. Moreover, the calibration of these models to the specific field of study remains a challenge. Chapter 2 and 3 are dedicated to finding a suitable petro-elastic model for sim2seis. In Chapter 2, by concentrating on the Gassmann’s fluid substitution model, in conjunction with the effective medium theories for solid and fluid components, a PEM is developed for sand-shale in the petrophysical domain by use of well-logs and the laboratory measurements. A major part of this chapter concerns the dry-rock characterisation, which in association with the rock stress-sensitivity remains the highest uncertainty in the PEM. Different sand-shale mixing theories and petrophysical models based on total and effective porosity are adapted for the Gassmann’s model and their implications on the 4D signal are assessed.

Finally, the necessity of calibration of the PEM parameters to the specific field of study is explained and an optimisation algorithm is presented, accordingly. Furthermore, in the context of sim2seis, the PEM requires additional considerations. Chapter 3 concerns the link between the parameters of the petrophysical and the simulation model domains. The static reservoir properties that appear in the fluid-flow equations are investigated to construct an appropriate rock model in the simulation model. The concepts of porosity and net-to-gross (NTG) in the petrophysical domain versus those in the engineering
domain are discussed, and the underlying relationships between the two disciplines are extracted.

### 1.4.2 Seismic modelling

The second key step of sim2seis is the seismic modelling. Different modelling techniques are developed for the 4D seismic modelling (Lecomte, 1996; Hokstad et al., 1998; Gjoystadal et al., 1998; Robertson and Chapman, 2000; Robertson et al., 1996; Kirchner and Shapiro, 2001). Although quantitative reviews of the different approaches are very scarce in the literature, there appears to be a bias in favour of more sophisticated techniques (e.g. numerical modelling). Nonetheless, as it is concluded in Chapter 4, not all of these models are fit for purpose, because they lack consistency with the philosophy of sim2seis. Following a discussion on the spectrum of the seismic modelling techniques in the context of sim2seis, a quantitative comparison is made between the two end-members: the 1D convolution is compared with pre-stack finite-difference seismic modelling, and the considerations that need to be made to ensure satisfactory results from 1D convolution are discussed.

Different attempts are made to distinguish the coupled effects of fluid phase and pressure changes from 4D seismic data (Landro, 2001; Tura and Lumley, 1999; MacBeth et al., 2006). In Chapter 4, it is shown how sim2seis modelling can be used to investigate the 4D response of pressure and saturation changes from different angle stacks. This method can also be used to calibrate the 4D inversion algorithms. Chapters 5 and 6 include the application of sim2seis to two different fields, where the importance of overburden properties and inactive cells are highlighted. The interpretation of the 4D tuning effects due to multiple fluid contact movements is not straightforward. Wavelet characteristics play an important role in such cases. In Chapter 6, the wavelet effects on the 4D response due to simultaneous movement of the oil-water contact and the gas-water contact in a water-bottom-drive reservoir is illustrated.
1.4.3 Scale and geometry

Due to the computational limits, it is not practicable to run fluid flow simulations at the fine scale of geological models. Typically, to reduce the number of cells, a group of grid-blocks in the geological model are merged together to represent one grid-block in the simulation model. The coarsening of the cells is done through a process known as upscaling. Upscaling is performed in both vertical and horizontal directions. In sound upscaling practice, it is intended to preserve the volume of hydrocarbon in place and the fluid-flow characteristics; nonetheless, the vertical upscaling inevitably will alter the pseudo-logs and hence the reflectivity series to be used in calculating the synthetic seismic traces in sim2seis, and the seismic response at each scale will be different. Figure 1.9 shows the different vertical scales in sim2seis. The variation of the seismic response at different vertical scales is illustrated in Chapter 3. The proposed solutions to decrease this effect, known as scale-dependent PEM, are challenged, and the difference between property upscaling and reflectivity upscaling is highlighted.
Different approaches for reservoir gridding exist (Aziz 1993). Grid blocks may be defined in terms of corner-point geometry or block-centred geometry. Block-centred geometry is the most straightforward technique, but corner point geometry has gained popularity because it yields a more visually realistic representation. The grid geometry implications on fluid flow are investigated in the literature (Fanchi 2001), and it is shown that there is little computational difference between the results of corner-point and block-centred geometry. However, very irregular corner point grids can lead to distortion of flood fronts and numerical stability problems. The grid orientation in respect to fluid flow can also have an effect on the lateral displacement and flow pattern. From the sim2seis perspective, the orientation of grids in the simulation model is usually different from the orientation of the seismic grid (inline and xline direction). This inconsistency is not significant on the sim2seis results; what matters is the relative scale of the seismic grid (bin size) and the horizontal grids in the simulation model. The amount of detail in the sim2seis results is a function of the lateral size of the simulation cells, seismic bin size and the horizontal seismic resolution, that is dictated by the seismic resolution function (Figure 1.10).

![Figure 1.10](image)

**Figure 1.10** Different lateral scales in sim2seis. The illustrations are in scale. (a) a cell from the geological model (50m×50m×1m), (b) a cell from the simulation model (100m×100m×5m), (c) the seismic bin size (25m×25m×25m); the size in the vertical direction represents an average length for the vertical resolution of the seismic data, and (d) the resolution function of the migrated seismic data; the shape and the size of this operator varies based on different factors.
details that lie below the horizontal seismic resolution are not resolvable in the
seismic domain. Chapter 4 covers the discussion related to the geometry and
horizontal scale, where the complications of extracting the pseudo-logs from
corner-point geometry grids and the considerations about horizontal scale in the
simulation and seismic domain are discussed in detail.

1.4.4 Using sim2seis to update the reservoir model

3D seismic data can be used to assess the property distribution within the
reservoir models. Generally, geostatistical methods are used to populate the
reservoir properties away from the wells. The reliability of such methods in
intra-well locations can be assessed by comparing the synthetic seismic from the
reservoir model and the observed 3D seismic. 4D seismic data can be used to
evaluate and update the dynamic features of the reservoir model. Using sim2seis
for update of the simulation model involves three steps:

1. Assess the mismatch between the synthetic and the observed 4D response
2. Isolate the parameters that cause the mismatch
3. Update the parameters

Firstly, the match quality between the synthetic and the observed 4D response
should be assessed. The comparison can be performed either qualitatively or
quantitatively (seismic history matching). Defining a misfit function in the
quantitative comparison is a challenge; a trace by trace comparison is only
feasible when the property distribution in the simulation model is fully
consistent with the observed 3D seismic i.e. the pre-production synthetic seismic
response is matched accurately to the pre-production observed seismic. However,
this process is not straightforward and the luxury of a simulation model fully
consistent with the 3D seismic is not often affordable. Depending on the efforts
in the geo-modelling stage, the degree of reservoir model consistency with the
3D seismic data varies, and even models with less consistency might be capable
of capturing the major anomalies of the 4D signature. In these circumstances, a
trace by trace comparison generally under-states the 4D match quality.
Therefore, to achieve a fairer evaluation, the comparison is performed on 4D
maps and a comparison criterion is designed that is able to take into account
the main features of the 4D signature. Another issue in quantitative comparison is that the absolute values of the sim2seis results are always different from the observed data; hence, a normalisation technique should be developed to make the comparison viable. Clearly, in a simulation model fully consistent with the 3D seismic data, this problem does not exist.

Hierarchy of uncertainty in Seismic History Matching

Once the mismatch has been recognised – either qualitatively by visual comparison or through quantitative methods – the source of the mismatch need to be identified; this is the step that requires the user’s insight into the process. Isolating the parameter (or a selection of parameters) depends on the heterogeneity of the reservoir and the reliability of the available information.

<table>
<thead>
<tr>
<th>Simulation model</th>
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<tbody>
<tr>
<td>- Model geometry</td>
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<tr>
<td>- Active/inactive geobody distribution (NTG)</td>
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<tr>
<td>- Fluid contacts</td>
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<tr>
<td>- Reservoir top and base</td>
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<tr>
<td>- Connectivity of reservoir units</td>
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<tr>
<td>- ...</td>
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<tr>
<td>- Production history matching</td>
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<tr>
<td>- Hierarchy of uncertainty</td>
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<table>
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<tr>
<th>Consistency?</th>
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</thead>
<tbody>
<tr>
<td>- Observed seismic</td>
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<tr>
<td>- Noise (acquisition)</td>
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<tr>
<td>- Processing and imaging</td>
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<table>
<thead>
<tr>
<th>PEM</th>
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<tbody>
<tr>
<td>- Dry-frame characterisation</td>
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<tr>
<td>- Stress-sensitivity</td>
</tr>
<tr>
<td>- Sand/shale properties</td>
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<tr>
<td>- Fluid properties</td>
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<tr>
<td>- Overburden/underburden properties</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Seismic modelling</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Wavelet</td>
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</table>

Table 1.5 Hierarchy of uncertainty in updating the simulation model using sim2seis.
This shows why the (seismic) history matching process is not a fully automatic task, and computers cannot be left alone to solve the problem. The concept of a hierarchy of uncertainty that was mentioned earlier is also applicable here. As is expected, the list of parameters in the hierarchy of uncertainty is more extensive in this case, compared to that for the (production) history matching. Table 1.5 shows the hierarchy of uncertainty for the process of updating the simulation model using sim2seis. Based on the case studies that are covered in this thesis, generally, the main source of uncertainty is the simulation model. However, in an application of SHM to the Girassol Field (Offshore Angola), Roggero et al. (2012) recognised that the PEM stress-sensitivity parameters to have a significant effect, and they were introduced as seismic history matching parameters.

Compared to production history matching, a strong controlling parameter on the seismic response is model geometry. The reliability of the observed 4D signal is also important; any 4D anomalies that are not genuine (i.e. not induced by the production effects) should be discarded in the updating process. Although not favourable, the modelling parameters (PEM and seismic modelling) can also be the source of mismatch. The best practice should be followed to minimise the modelling artefacts in such a way that the detected mismatch can be attributed to the simulation model.

Finally, in the last step, after isolating the parameters that cause the mismatch, they should be updated using an efficient approach. Generally this is carried out in an iterative process until a satisfactory match is achieved. As stated by Fanchi (2001), ‘a clear understanding of the study objectives should be the standard for making the decision.’ In Chapters 5 and 6, in two different case studies, different parameters that control the sim2seis response are studied by focusing on the hierarchy of uncertainties and suggestions are made regarding the update of the simulation model based on qualitative evaluation of sim2seis results. The third step, the actual update of the simulation model, is beyond the scope of this thesis and is fit for a project concerning seismic history matching. The central theme of Chapters 5 and 6 is to highlight the value of sim2seis in model-based 4D seismic data interpretation.
1.5 Publications and deliverables

1.5.1 Publications

Selected aspects of this research have been presented in some conferences and meetings:


1.5.2 Tangible outcomes of this research

Putting my ideas into practice was a painstaking task. The existing commercial packages did not offer the capabilities that were required to investigate different aspects of the sim2seis workflow. Specifically, compatibility with the Eclipse simulation models and flexibility of implementing the different petro-elastic models were important to achieve the goal of the thesis. I dedicated a considerable amount of my research to the development of a deliverable sim2seis package. I am glad that the outcome of this research has also been used in several research projects in the Edinburgh Time-Lapse Project (ETLP) and the MSc programme in the Institute of Petroleum Engineering at Heriot-Watt University. What follows are a summary of some of the programmes that were created during this research.
3D simulator to seismic modelling package

The simulator to seismic modelling package is programed using MatLab. Here are some of the features of the package:

- It is compatible with Eclipse 100 simulation models.
- All the PEM parameters are exported as ASCII files and can be imported to the simulation model grid.
- It comes with a very accurate pseudo-log extraction tool, which can deal with the complexities of corner point gridding in simulation models, such as pinch outs, faults, and non-vertical pillars.
- It has the capability of using the observed seismic trace layout to generate the synthetic traces at the same location as the observed traces.
- It has the capability to generate a synthetic seismic within a polygon over the reservoir.
- Use of an external wavelet is available.
- The option for aligning the synthetic seismic to the observed seismic is available.
- Allows user to extract two-way-time horizons in ASCII format, which can be used for time-shift analysis.
- It provides a *time matching* option, which allows the user to remove the time-shifts from the reflectivity series of different surveys by choosing a reference seismic vintage.
- It provides an option that allows the user to map any seismic attributes to the reservoir grid. Time to depth conversion is performed based on PEM velocities.

2D simulator to seismic modelling package

This package is programed using MatLab. It is compatible with Eclipse 100 simulation models. The main feature of this program is the ability to convert CPG to Cartesian grids along any arbitrary 2D line over the reservoir grid.
2D finite-difference elastic seismic modelling program

This is programmed in Fortran90. This is based on a 2D staggered-grid finite difference (FD) scheme (Virieux, 1986; Levander, 1988) to solve the elastodynamic (velocity-stress) wave equation (2nd order in time and 4th order in space). To increase the accuracy and the computational efficiency of the FD modelling, Holberg’s (1987) differentiators are implemented in the calculations. To minimise the effect of the spurious reflections from the computational boundaries of the model, the perfectly matched layer (PML) method (Berenger, 1994) is implemented at four sides of the model.
CHAPTER 2

A Suitable Petro-elastic Model for Sim2seis: Seismic Petrophysics Perspective
2.1 Introduction

A review of the published literature in Geophysics, Engineering and Petrophysics reveals that the first use of the phrase *petro-elastic model (PEM)* is coincident with the early works on 4D seismic data interpretation (Al-Najjar et al., 1999). Originating from the 4D community, the development of the PEM derived from the need to evaluate the production-induced effects (i.e. changes in saturation and/or pore pressure) on in-situ elastic properties and the seismic signature of the reservoir.

Different features of the PEM are extensively covered in the literature (see Mavko et al., 2009 for a review). This includes issues such as the various fluid substitution models, fluid substitution in heterogeneous matrix-clay mixtures, in-situ acoustic properties of fluids, fluid-mixing theories, and dry-rock characterisation. Each of these concepts can be a subject for an independent research; however, the focus in this thesis is to provide a pragmatic model by putting together the different components of the PEM. This model captures both effects of saturation and pore pressure variations, together with the static parameters, in a single 4D framework, and, more importantly, it is applicable to the sim2seis analysis.

In this chapter, well-log data are used to understand how different rock constituents in the petrophysics domain contribute to the 4D response i.e. to investigate the influence of the solid and fluid components on the changes in the elastic parameters (\(\Delta V_p, \Delta V_s, \Delta \rho\)) due to pore pressure and saturation changes. To do so, a petro-elastic model is designed that takes pore pressure and saturation variations into account through reconstruction of the \(V_p, V_s,\) and \(\rho\) logs, based on the rock-constituents. Smith (2011) summarises three different approaches for the reconstruction of the \(V_p, V_s,\) and \(\rho\) logs from seismic petrophysics: 1) application of effective medium models, 2) application of heuristic models, and 3) application of empirical models. He also mentions that the most rapid and robust approach for generating the pseudo-logs is via multiple linear regression. However, it should be emphasised that the desired PEM in this thesis, while being practical, should fulfil the following three essential criteria:
1) it acknowledges the physics of rock and fluid;

2) it is able to capture the production induced effects; this implies including a fluid-substitution model to take the saturation changes into account and a stress-sensitivity model to capture the effect of changes in pore pressure;

3) it is applicable to sim2seis application; hence, it should be compatible with the parameters of the simulator in the engineering domain.

In this chapter, two major components of the PEM, 1) fluid substitution, and 2) dry-rock characterisation are discussed in relation to matrix-clay mixtures.

### 2.2 Fluid substitution

Fluid substitution concerns the prediction of changes in density and velocities of saturated rocks due to the changes in pore fluid phases or changes in the acoustic properties of the existing fluids. Modelling the changes in density is straightforward, because the bulk density is linearly dependent on the volume fraction of each rock constituent and their individual densities (Section 2.7). For velocities, Gassmann’s model (1952) is the most frequently used theory (Equations 2-1 and 2-2).

$$\kappa_{sat} = \kappa_{dry} + \frac{(1 - \kappa_{dry}/\kappa_m)^2}{\phi/\kappa_f + (1 - \phi)/\kappa_m - \kappa_{dry}/\kappa_m^2} \quad (2-1)$$

$$\mu_{sat} = \mu_{dry} \quad (2-2)$$

where $\kappa_{sat}$ and $\mu_{sat}$ are the saturated bulk and shear modulus, $\kappa_m$ and $\mu_m$ are mineral bulk and shear modulus, $\kappa_{dry}$ and $\mu_{dry}$ are dry-rock bulk and shear modulus, $\kappa_f$ is the fluid bulk modulus, and $\phi$ is the porosity. Gassmann developed this theory for a porous medium with a single homogeneous solid component and a single homogeneous fluid phase. These assumptions break down in natural sediments, where the rock is comprised of different minerals and the pore space is occupied by both water and hydrocarbon. More
sophisticated models are proposed to generalise fluid substitution by introducing additional quantities into Gassmann’s equations (see Mavko et al., 2009 for a review). However, it should be noted that calibration of reservoir-dependent PEM parameters is not straightforward; this is due to the fact that PEM parameters outnumber the available measured quantities that can be used for calibration. As the PEM calibration is an underdetermined problem, introducing more variables into the Gassmann equations is not a favourable option, because it increases the uncertainty of the calibration process. Therefore, effective medium theories for solid and fluid components are utilized to extend the Gassmann’s model to heterogeneous multi-mineral, multi-fluid systems; this idea is supported by the published applications of Gassmann’s model in such cases (Simm, 2007; Smith, 2003).

2.3 Acoustic properties of fluids

In-situ acoustic properties of reservoir fluids (oil, gas, brine) are required for fluid substitution. Batzle and Wang (1992) provide the most widely used method to allow for variations of the fluid properties with pore pressure and temperature changes. The popularity of their work can be tied to the ease of use of the proposed equations, which are generated by a limited number of parameters. Black-oil properties (oil API, solution gas-oil ratio, oil-formation volume factor), and gas gravity are used to characterise the hydrocarbon properties. Brine properties depend only on NaCl salinity. Walls and Dvorkin (2005) showed that, in the higher pressure range (more than 50 MPa), Batzle and Wang equations underestimate the oil bulk modulus substantially. In the case of the compositional models where the volume fractions of different hydrocarbon components are available, some additional calculations are required to adapt the Batzle and Wang equations to include the compositional data (Hamdi et al., 2012). PVT measurements can also be used for the acoustic properties of the oil. Clark (1992) describes the modifications that should be applied to PVT measurements to be used in fluid substitution.
Figure 2.1 Static and dynamic parameters in the simulation model for a turbidite reservoir in the North Sea. (a) pore volume fraction, (b) sand volume fraction, (c) change in pore pressure after 6 years of production, (d) change in water saturation after 6 years of production, (e) change in gas saturation after 6 years of production, (f) the predicted percentage of change in acoustic impedance.
It should be noted that the major saturation-related changes are due to a change in the fluid phases, i.e. where hydrocarbon has been replaced by water or gas has come out of solution. The effects of changes in fluid properties due to pressure changes are very subtle. In application of PEM to a simulation model in a turbidite reservoir in the North Sea, the effect of the fluid’s pressure sensitivity on the 4D response is investigated. The lithology distribution and the change in pressure and saturation over a period of production are shown in Figure 2.1. This field is a good 4D laboratory, as it includes different combinations of pore pressure and saturation changes. Here, two different PEMs are examined: PEM1 considers the variations of fluid properties with pore pressure changes, whereas this effect is ignored in PEM2 by assigning constant values to each fluid phase. Figure 2.2 shows that in most of the reservoir compartments, the error in the 4D predictions (change in acoustic impedance) due to ignoring the fluid pressure sensitivity is less than 5%; however, in the case of large pressure changes (up to 14 MPa around injector 16) or locations with gas breakout, ignoring this effect results in errors of up to 10% in 4D predictions. As mentioned earlier, in reservoir rocks, different fluid phases can be present together in the pore space. To use Gassmann’s equations in such settings, fluids should be represented by a single bulk modulus. Harmonic averaging (Domenico, 1974) is commonly used to calculate an effective fluid bulk modulus, \(\kappa_{fl}^{\text{eff}}\), that represents the fluid mixtures (Equation 2-3).

\[
\frac{1}{\kappa_{fl}^{\text{eff}}} = \left( \frac{S_w}{\kappa_w} + \frac{S_o}{\kappa_o} + \frac{S_g}{\kappa_g} \right)
\]

(2-3)

where \(S_w, S_o,\) and \(S_g\) are water, oil and gas saturations respectively, and \(\kappa_w, \kappa_o, \kappa_g\) are the water, oil and gas bulk modulus respectively. Dvorkin and Nur (1998) discuss the case where fluid is arranged in fully saturated patches that are surrounded by dry or partially saturated regions, so that fluid distribution is patchy. The effective fluid properties of the patchy model can be approximated by arithmetic average (Equation 2-3) (curve L in Figure 2.3).

\[
\kappa_{fl}^{\text{eff}} = S_w\kappa_w + S_o\kappa_o + S_g\kappa_g
\]

(2-4)
Figure 2.2 The error in the predictions of changes in acoustic impedance due to ignoring the effect of pressure sensitivity of the fluid properties (see Figure 2.1 for pressure and saturation changes and the reference case for the impedance changes). In most of the reservoir compartments in this map, the error in 4D predictions is negligible. The value $\Delta(\Delta I_P)$ represents the percentage of error in prediction of $\Delta I_P$ between the two PEM models; e.g. for $\Delta I_P^2 = 2\%$ and $\Delta(\Delta I_P) = 10\%$, $\Delta I_P^2 = 2 \pm 0.2\%$.

MacBeth and Stephen (2008) argue that Equation 2-4 is no more than a mathematical limit and does not represent any known physical saturation distribution (curve U in Figure 2.3). It is mentioned that “the estimates of the effective fluid modulus from seismic cannot be directly converted to the true pore-volume weighted mean saturation determined from fluid flow principles by Equation 2-3. One of the reasons is that seismic waves sample the reservoir geology and production induced saturation heterogeneity in a different way from the fluids.” MacBeth and Stephen (2008) applied an effective medium and perturbation theory to the determination of the seismic properties of heterogeneous saturation distribution for oil-water systems in turbidite reservoirs (Equation 2-5).

\[
\frac{1}{\kappa_{fI}^{\text{eff}}} = A \left( \frac{S_w}{\kappa_w} + \frac{1-S_w}{\kappa_o} \right) 
\]  

(2-5a)

\[
A = \left( 1 + a\sigma_\phi^2 + b\kappa_{fI}^{-1}\sigma_\phi^2 + c\kappa_{fI}^{-2}\sigma_\phi^2 \right)^{-1} 
\]  

(2-5b)

where
Figure 2.3 Different effective fluid models (modified from MacBeth and Stephen, 2008). L and U – the reference curves given by Equation (2-3) and the non-physical end-member of Equation (2-4). P – saturation law proposed by MacBeth and Stephen (2008) (Equation 2-4) to take into account fluctuations in porosity and saturation state and their cross-correlation.

\[
\sigma_{\phi}^2 = \frac{1}{N} \sum_{i=1}^{N} (\delta \phi)^2 \\
\sigma_{\phi S}^2 = \frac{1}{N} \sum_{i=1}^{N} \delta \phi \delta S_w \\
\sigma_S^2 = \frac{1}{N} \sum_{i=1}^{N} (\delta S_w)^2 \\
a = \frac{2\beta}{\phi(1-\beta \phi)} \\
b = \left(\frac{a_r}{\phi}\right) \left(1 + \frac{2\beta \phi}{1-\beta \phi}\right) \\
c = a_r^2
\]

where $\bar{S}_w$ is the average water saturation in the interval being analysed, $\overline{\kappa_{fl}}$ is the fluid bulk modulus obtained by harmonic average (Equation 2-3) as a function of $\bar{S}_w$. In above equations, $\beta = 1/\phi_c$ and $\phi_c$ is the critical porosity (Nur et al. 1998) and $a_r = (1/\kappa_o - 1/\kappa_w)$. Bed-scale fluctuations in porosity $\delta \phi$ and saturation $\delta S_w$ are defined such that the saturation and porosity for each bed can be written as $S_w \approx \bar{S}_w + \delta S_w$ and $\phi \approx \bar{\phi} + \delta \phi$. The perturbation terms $\delta \phi$ and $\delta S_w$ are related to variances or covariances of their distributions,
according to Equations 2-5a, 2-5b, and 2-5c. In a PEM application to a simulation model in a turbidite reservoir in the North Sea (Figure 2.1), harmonic averaging (Equation 2-3) is compared with the proposed equation by MacBeth and Stephen (2008) (Equation 2-4). Based on well data, $\sigma_\phi \approx 0.03$ and $\phi_c = 0.4$. The simulation model is downscaled by factor of five in the vertical direction to calculate the variations in saturation ($\sigma_{\phi_s}$, $\sigma_s$). Figure 2.4 shows the saturation profile in the coarse cell (thickness $\approx 3$m) compared to the refined model (thickness $\approx 0.6$m). The parameters in Equations 2.4 and 2.5 are shown in Figure 2.5. Figure 2.6 shows the error in predictions of changes in acoustic impedence due to ignoring the saturation heterogeneity in the fluid mixing (Equations 2.3 and 2.4). Apart from at water fronts, where the error goes up to $10\%$ due to saturation heterogeneity being pronounced, in other water flooded areas the error is less than $5\%$. In this study, the simulation model was fine enough ($dz \approx 3$m) to capture the vertical heterogeneity; thus the difference between harmonic averaging and the method by MacBeth and Stephen is insignificant.

**Figure 2.4** Water saturation at two different vertical scales; (a) original Eclipse model with average cell thickness $3$m, (b) the refined Eclipse model by factor of five in the vertical direction. The saturation heterogeneity ($\sigma_{\phi_s}$ and $\sigma_s$) in each cell of the original simulation model is calculated based on the variations of the saturation in the refined model.
Figure 2.5 Parameters of fluid mixing theory by MacBeth and Stephen (2008). (a) $a = \frac{2\beta}{\bar{\phi}(1-\beta\bar{\phi})}$, (b) $b = \left(\frac{a\bar{\phi}}{\bar{\phi}}\right)(1 + \frac{2\beta\bar{\phi}}{1-\beta\bar{\phi}})$, (c) $c = a\bar{\phi}^2$, (d) $\sigma_s^2 = \frac{1}{N} \sum_{i=1}^{N} (\delta S_w)^2$, (e) $\sigma_{\phi S}^2 = \frac{1}{N} \sum_{i=1}^{N} \delta\phi \delta S_w$, (f) $A = \left(1 + a\sigma_{\phi}^2 + b\kappa_f(\sigma_{\phi S}^2 + c\kappa_{f(2}\sigma_s^2)\right)^{-1}$. 

39
Figure 2.6 The negligible error in the prediction of the changes in acoustic impedance due to ignoring the saturation heterogeneity in fluid mixing (see Figure 2.1 for pressure and saturation changes and the reference case for the impedance changes). In most of the water flooded areas, the error is less than 5%. However, in water fronts (marked by arrows), the error goes up to 10%. Parameter $a_f$ in Equations 2-5e and 2-5f is a function of fluid bulk modulus, which, in high pore pressure build-up around injector I6, results in a bigger difference between the two methods (to up to 20%). (The value $\Delta(\Delta I_p)$ represents the percentage of error in prediction of $\Delta I_p$ between the two PEM models; e.g. for $\Delta I_p^1 = 2\%$ and $\Delta(\Delta I_p) = 10\%, \Delta I_p^2 = 2 \pm 0.2\%).$

2.4 Porosity concepts in fluid substitution

Porosity is a basic concept, but different understandings of this concept across laboratory, petrophysical and engineering disciplines results in inconsistencies in communication between these domains. The multi-disciplinary nature of sim2seis implies a necessity to reach to a common ground for this concept between the petrophysical domain – where PEM is developed – and the engineering domain – where PEM is utilised. Therefore in the next few pages, the petrophysical perspective on porosity is outlined. In Chapter 3, the engineering viewpoint and the connection with the petrophysical domain is described.

2.4.1 Porosity terminology

In theory, the rock model in the petrophysical analysis can be very complex, with a varying number of constituents (Figure 2.7). In practice, a more
simplified four-component (matrix, clay, water, hydrocarbon) model (Hook, 2003) is commonly used for petrophysical analysis to describe reservoir rocks (Figure 2.8). Compared to the model in Figure 2.7, the four-component model has a smaller number of volume fractions, yet retains sufficient diversity to explain 3D/4D seismic observations. Different components of this model are as follows:

\[ V_{ma} \quad \text{volume fraction of matrix grains} \]
\[ V_{dcl} \quad \text{volume fraction of dry clay} \]
\[ V_{cbw} \quad \text{volume fraction of clay-bound water} \]
\[ V_{ct} \quad \text{volume fraction of wet clay} (V_{dcl} + V_{cbw}) \]
\[ V_{cap} \quad \text{volume fraction of capillary-bound water} \]
\[ V_{fw} \quad \text{volume fraction of free water} \]
\[ V_{hyd} \quad \text{volume fraction of hydrocarbon} \]
\[ V_{pt} \quad \text{total pore volume} \]
\[ V_{pe} \quad \text{effective pore volume (excluding clay-bound water)} \]
\[ V_b \quad \text{bulk volume of rock} \]

**Figure 2.7** A complex description of rock constituents (Eslinger and Pevear, 1998).
Figure 2.8 Four component description of a typical reservoir rock; (a) the geometry of components (matrix, clay, water, hydrocarbon), (b) the terminology of the components. $\phi_t$ and $\phi_e$ refer to total and effective porosity (Hook, 2003).

The following porosity terms can be defined according to this model:

**Total porosity** is the entire fluid fraction as the ratio of total pore volume ($V_{pt}$) divided by bulk rock volume ($V_b$).

$$\phi_t = \frac{V_{pt}}{V_b}$$

**Effective porosity** is total porosity less clay-bound water. Clay-bound water is not mobile and is electrochemically bound to clay particles. The amount of clay-bound water depends on salinity of the water and clay type.
\[
\phi_e = \frac{V_{pe}}{V_b} = \frac{V_{pt} - V_{cbw}}{V_b}
\]

**Connected porosity** includes only the pore volume that can be contacted by fluids at the present time. This quantity is determined in the laboratory experiments on core samples that are not disaggregated. Since retaining the clay-bound water in core samples is difficult, measurement of this particular porosity includes the clay-bound water. Note that in neither of the definitions for total and effective porosity is there a reference to the need for the porosity to be connected.

In a few publications (e.g. Gurevich & Carcione, 2000) the matrix and clay are treated as two distinct entities with their associated porosities, namely *sand porosity* and *clay porosity*.

**Clay porosity** is a concept associated with the wet-clay mineral fraction only, considering the volume fraction of clay-bound water as clay porosity.

\[
clay\ porosity = \frac{V_{cbw}}{V_{cl}} = \frac{V_{cbw}}{V_{dcl} + V_{cbw}}
\]

**Sand porosity** is a concept associated with the matrix only. In clean sands (also known as Archie sands), where \( V_{cl} = 0 \), sand porosity is equal to the effective porosity.

Figure 2.9 shows an example of different porosity terms that are calculated for a well in a turbidite system in the North Sea. Because the reference volume in the calculation of sand porosity is not the bulk volume of the rock, it can have an unreasonably large values, I believe, therefore, that effective/total porosity are more appropriate terms than sand/clay porosity in the description of reservoir rocks.

\[
sand\ porosity = \frac{V_{pe}}{V_{pe} + V_{ma}}
\]
Figure 2.9 Histograms of different porosity terms for the well in Figure 2.10. The sand porosity values go up to unphysical values of one. The large values of sand porosity are associated with the intervals where matrix volume fraction compare to effective porosity volume is negligible i.e. the shaly intervals with high effective porosity.

2.4.2 Clay versus shale

In the rock physics literature, the terms ‘shale’ and ‘clay’ are sometimes used interchangeably (Spooner, 2014). However, ‘shale’ is distinguished from other clastic sedimentary rocks by its grain size, whereas ‘clay’ is used to refer to a set of minerals defined by its specific composition. Shales may contain a variety of clay and non-clay minerals. Clay minerals are the most abundant components in shales. In the context of this thesis, the variation of elastic properties due to differences in mineralogy of the matrix versus clay is highlighted, and the grain size or sorting is not addressed. Therefore the term ‘matrix-clay’ combination is used instead of ‘sand-shale’ combination.

2.4.3 Porosity and fluid substitution – total, effective, or movable fluids?

From the PEM perspective, it is appreciated in the seismic petrophysics literature that different porosity choices (total or effective) exist for fluid substitution (May, 2005). However, a thorough assessment of these models is not covered, and both approaches attempt to validate Gassmann’s model with
only a mere reference to the underlying porosity basis. Following Wang (2001), Gassmann’s model requires that the pore fluid pressure induced by the passing wave be in full equilibrium within the time-frame of half of a seismic wave period. To fulfil this criterion, all the pores need to be interconnected. Wang (2001) and Simm (2007) reported that the effective porosity model fulfils the underlying assumptions of Gassmann’s theory regarding the full pore-space interconnectivity, and the clay-bound water should be considered as a part of the dry frame. However, using numerical and analytical analyses, Grechka (2009) showed that under some conditions (as long as the aspect ratios of the pores are greater than approximately 0.2), the presence of disconnected porosity is unlikely to invalidate Gassmann’s predictions. The use of total porosity has also been reported in a number of fluid substitution studies and laboratory measurements (e.g. Grochau and Gurevich, 2009). It should be noted that maintaining the effective porosity conditions for laboratory measurements is difficult; hence, most laboratory measurements tend to be based on total porosity (Taggart 2002).

Yan et al. (2013) suggested that the porosity in Gassmann’s equation should include the volume fraction of pore fluids that is connected and relaxed, while the other fraction of pore fluids should be included in the rock matrix. They used irreducible water saturation to quantify the pore fluids that cannot be driven out by hydraulic force. Thus, in addition to total and effective porosity, a third choice also exists for porosity in Gassmann’s model. In fact, similarly to clay-bound water, capillary-bound fluids will not be replaced during fluid substitution; one can therefore limit the fluid substitution exercise to the portion of the pore space occupied by *movable fluids* only i.e. effective porosity less irreducible water and residual hydrocarbon. In this setting, both the clay-bound water and capillary-bound fluids are considered to be a part of the rock frame. The uncertainties associated with the estimation of the irreducible water saturation and residual oil volume fractions is one of the issues in the application of the movable fluid model. Mathews et al. (2013) utilised the movable fluids model in a fluid substitution exercise; they reported that, compared to the effective porosity model, this model derives a more reasonable range for the dry-rock bulk moduli. Also, by replacing gas with brine, they
reported a lower fluid effect (i.e. less change in impedance) compared to the model based on effective porosity, and argued that the results based on the movable fluid model are more realistic. Nonetheless, in the absence of repeat logs – where the sonic and density logs are acquired from the intervals that have undergone changes in the fluid content – it is very challenging to validate different hypotheses regarding the porosity models for fluid substitution. In fact, one major issue in most PEM discussions is how to validate the underlying theories and assumptions in in-situ reservoir conditions. As an alternative to repeat logs, it is shown in Chapter 5 how sim2seis can be used to validate the petro-elastic models based on different porosity bases.

2.4.4 Porosity concepts in fluid substitution – modelling results and discussions

In this section, the three porosity choices (total, effective and movable fluids) are examined in a fluid substitution study on an appraisal well in a North Sea turbidite reservoir. The 200 meter thick interval of interest comprises four (seismically) thin stacked reservoirs (Figure 2.10). In all three cases of porosity, the following steps are undertaken to substitute oil with brine:

1) The matrix and fluid constituents corresponding to each porosity case are defined. Figure 2.11 illustrates the different constituents in each case. These parameters are summarised in Table 2-1.

<table>
<thead>
<tr>
<th>Porosity basis</th>
<th>Matrix</th>
<th>Fluids</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total porosity</td>
<td>$V_{ma}, V_{dcl}$</td>
<td>$V_{cbw}, V_{cap}, V_{fw}, V_{hyd}$</td>
</tr>
<tr>
<td>Effective porosity</td>
<td>$V_{ma}, V_{dcl}, V_{cbw}$</td>
<td>$V_{cap}, V_{fw}, V_{hyd}$</td>
</tr>
<tr>
<td>Movable fluids</td>
<td>$V_{ma}, V_{dcl}, V_{cbw}, V_{cap}, V_{hyd}^{*}$</td>
<td>$V_{fw}, V_{hyd}^{**}$</td>
</tr>
</tbody>
</table>

*residual hydrocarbon
** producible hydrocarbon

Table 2-1 Different constituents of rock and fluids in each porosity basis.
Figure 2.10 An appraisal well in a stacked turbidite reservoir in the North Sea. In the first panel, CLAY refers to dry clay volume fraction, CBW refers to clay-bound water, CAP to capillary-bound water, FW to free water, and HYD to hydrocarbon volume fraction. The second panel shows the seismic signature of the four thin sand intervals.

Figure 2.11 Three porosity models and the associated rock and fluid constituents. The Gassmann’s model components in each case are marked as black (minerals fraction) and grey (fluid fraction). Although the porosity volume fraction in each case is different, only the movable portion (red box) is substituted in the fluid substitution in the three models.
2) Voigt-Reuss-Hill averaging (Equations D-1 to D-3 in Appendix D) is applied to calculate the effective mineral bulk/shear modulus \((\kappa_m, \mu_m)\) in the matrix. It should be noted that in effective porosity and movable fluids models, some fluid components are considered as a part of the rock matrix (Table 2-1).

3) Harmonic averaging is used to calculate the effective bulk modulus of the fluid mixtures \((\kappa_{ft})\).

4) Using \(V_P, V_S, \rho\) logs, Gassmann’s model is used to extract the in-situ dry-rock bulk modulus \((\kappa_{dry})\).

5) Oil is substituted with brine to obtain the new effective fluid bulk modulus.

6) The extracted dry-rock bulk modulus (step 4), the effective mineral moduli (step 2), and the new fluid bulk modulus (step 5) are used to calculate the brine saturated bulk modulus. It should be noted that the volume fractions of porosity and fluids that contribute to the fluid substitution vary in each porosity case.

Figure 2.12 and Figure 2.13 show the results of fluid substitution for the three porosity cases. In the total porosity model, the effective mineral moduli consist of the solid components only. In the effective porosity model, by including the clay-bound water into the effective mineral bulk modulus, the effective mineral moduli decrease; the decrease is higher in clay-rich intervals, where the volume of clay-bound water is higher. On the other hand, in the movable fluids model, where the capillary-bound fluids \((S_{wi}, S_{or})\) are also included in the matrix, the mineral bulk modulus is mainly decreased in the sand intervals. Interestingly, although the effective mineral bulk modulus in all three cases is different, the extracted dry-rock bulk moduli are very similar. By replacing oil with brine, the changes in impedances are very similar between effective and total porosity cases. This is due to the fact that, in sand intervals, the volume of clay-bound water, and hence the difference between effective and total porosity, is small. However, the movable fluids model predicts higher changes in impedances due to fluid substitution. In this case, the saturation bounds vary between 0 and 1,
Figure 2.12 Fluid substitution in three porosity models (PHIT: total porosity, PHIE: effective porosity, PHIEM: movable fluids). Panel 2) $\mu_m$ is the effective mineral shear modulus; Panel 3) $\mu_{dry}$ is the dry-rock shear modulus; Panel 4) $\kappa_m$ is the effective mineral bulk modulus; Panel 5) $\kappa_{dry}$ is the dry-rock shear modulus; Panel 6) $\kappa_{sat1}$ is the saturated bulk modulus for the reservoir fluids (panel 1); $\kappa_{sat2}$ is the bulk modulus for the case where the movable oil (HYD) is replaced with brine; Panel 7) $V_{p1}$ is the compressional velocity for the reservoir fluids; $V_{p2}$ is the compressional velocity for the case where the movable oil (HYD) is replaced with brine; Panel 8) $\rho_1$ is the density for the reservoir fluids; $\rho_2$ is the density for the case where the movable oil (HYD) is replaced with brine; Panel 9) $I_{p1}$ is the acoustic impedance for the reservoir fluids; $I_{p2}$ is the acoustic impedance for the case where the movable oil (HYD) is replaced with brine; Panel 10) $\Delta I_p$ is the percentage of change in acoustic impedance due to fluid substitution. $\Delta I_{PHIEM2}$ refers to the case where the dry-rock moduli based on effective porosity is used for movable fluid porosity model. For better visibility, the interval marked by the red box is shown in Figure 2.13.
### Figure 2.13 Fluid substitution in three porosity models (PHIT: total porosity, PHIE: effective porosity, PHIEM: movable fluids), showing the details of the interval marked in the red box in Figure 2.12. **Panel 2)** $\mu_m$ is the effective mineral bulk modulus; **Panel 3)** $\mu_{dry}$ is the dry-rock shear modulus; **Panel 4)** $\kappa_m$ is the effective mineral bulk modulus; **Panel 5)** $\kappa_{dry}$ is the dry-rock shear modulus; **Panel 6)** $\kappa_{sat2}$ is the saturated bulk modulus for the reservoir fluids (panel 1); $\kappa_{sat2}$ is the bulk modulus for the case where the movable oil (HYD) is replaced with brine; **Panel 7)** $V_{P1}$ is the compressional velocity for the reservoir fluids; $V_{P2}$ is the compressional velocity for the case where the movable oil (HYD) is replaced with brine; **Panel 8)** $\rho_1$ is the density for the reservoir fluids; $\rho_2$ is the density for the case where the movable oil (HYD) is replaced with brine; **Panel 9)** $I_{P1}$ is the acoustic impedance for the reservoir fluids; $I_{P2}$ is the acoustic impedance for the case where the movable oil (HYD) is replaced with brine; **Panel 10)** $\Delta I_P$ is the percentage of change in acoustic impedance due to fluid substitution. $\Delta I^{PHIEM2}_P$ refers to the case where the dry-rock moduli based on effective porosity are used as the movable fluid porosity basis.
Figure 2.14 The normalised bulk modulus $\frac{\kappa_{\text{dry}}}{\kappa_m}$ for different porosity models, (a) total porosity, (b) effective porosity, (c) movable fluids. The more scattered distribution of data points in the case of movable fluids is due to including fluid components in the matrix; this makes it difficult to relate the dry-rock moduli to the effective mineral moduli.

whereas, in the effective porosity model, the saturation bounds vary between $S_{\text{wi}}$ and $S_{\text{ar}}$; in other words, the contrast between the effective bulk modulus of the fluids before and after water flooding is higher in the case of the movable fluids. Figure 2.14 shows the normalised bulk modulus $(\frac{\kappa_{\text{dry}}}{\kappa_m})$ for the three cases. The greater degree of scatter for the movable fluid model indicates that the dry-rock characterisation is more challenging in this case. This is not in agreement with the result of Mathews et al. (2013), where they reported a more reasonable range for the dry-rock bulk moduli for a movable fluid model. The volume fractions of different rock components are input parameters to the PEM calculations. The estimation of $S_w$, $V_{ct}$ and porosity are prone to some uncertainties, which can result in differences in PEM calculation.

In a PEM application to a simulation model from a turbidite field in the North Sea, the 4D responses of the different porosity models are examined. The pore volume in the simulation model is equivalent to the effective porosity. Therefore, to be able to calculate the total porosity, a regression based on $V_{ct}$ and $\phi_e$ (Figure 2.15) is used to calculate the clay-bound water volume fraction in the model. To calculate the volume fraction of the movable fluids,
the saturation end members based on the relative permeability curves (Figure 2.16) are used to exclude the volume fractions of capillary-bound fluids. As mentioned earlier, dry-rock characterisation in the case of movable fluids is challenging; however, considering the small difference in the dry-rock values between the three porosity cases (panel 5 in Figure 2.12 and Figure 2.13), as an approximation, the dry-rock moduli for the effective porosity is also applied to the movable fluids. As shown in Figure 2.12 and Figure 2.13 (panel 10), the error due to this approximation is not significant. The results of applying PEM to the simulation model for the three cases are shown in Figure 2.17 and Figure 2.18. Unlike the analysis in the log domain, the results of the total and effective porosity models are not identical; As will be discussed in detail in Chapter 3, this is due to the fact that the lateral variability in the reservoir model is greater than in the log data, where the number of cells with non-zero clay-bound water volume (clay-rich sands) is not negligible. The movable fluids model predicts a higher impedance difference due to oil being replaced by water; however, in the case of gas breakout, the movable fluids model has lower predictions. Mathews et al. (2013) also reported a similar response of the movable fluids model for gas being replaced by water. Nonetheless, it is clear that their generalisation of the gas response to fluids, in stating that the ‘movable fluids model represents lower magnitude fluid effects’ is not applicable to the case where oil is replaced with water. Table 2-2 and Figure 2.19 summarise the difference between the three porosity cases in estimating the changes in saturated bulk modulus due to water-flooding and gas-breakout.

<table>
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Table 2-2 The difference between predictions of the three porosity models for fluid substitution. $\phi_t$, $\phi_e$ and $\phi_{mf}$ are the total porosity, effective porosity and movable fluid volume fraction respectively. $\kappa_{f11}$ is the effective bulk modulus of fluids in an oil saturated rock (pre-production). $\kappa_{f12}$ is the effective bulk modulus of fluids after water flooding and gas breakout. $\kappa_{sat1}$ and $\kappa_{sat2}$ are the saturated bulk moduli corresponding to $\kappa_{f11}$ and $\kappa_{f12}$. $\Delta(\kappa_{sat})$ is the percentage of change in saturated bulk modulus due to the fluid substitution.
Figure 2.15 A regression based on $V_{ct}$ (volume of wet-clay) and $\phi_e$ is used to estimate the volume of clay-bound water $V_{cbw}^{reg} = 0.17V_{ct} - 0.16\phi_e$. This regression is used to calculate the clay-bound water and total porosity in the simulation model.

Figure 2.16 The saturation end members ($S_{wi}$ and $S_{or}$) from relative permeability curves are used to calculate the capillary-bound fluid and movable fluid volume fractions in the simulation model.
Figure 2.17 4D predictions (change in acoustic impedance in percentage) for each porosity model: (a) total porosity, (b) effective porosity, (c) movable fluids model. Blue colours show hardening due to water flooding, and warm colours show softening. Softening around P4 and P2 is due to gas breakout, and around I6 is due to pressure build-up. The histograms of variations in acoustic impedance changes are shown in Figure 2.18.
**Figure 2.18** Histogram of 4D predictions (change in acoustic impedance) for each porosity model; (a) total porosity, (b) effective porosity, (c) movable fluids. By moving from a total porosity to a movable fluids model, less softening due to gas breakout and more hardening for water flood are predicted.

**Figure 2.19** Saturated rock bulk modulus versus fluid bulk modulus shows the difference between different porosity models (effective, total and movable fluids) in fluid substitution for the two cases of oil being replaced by water (water flood) and oil being replaced by gas (gas breakout). This diagram shows the values of $\kappa_{fl}$ at different porosity bases and explains why movable porosity results in higher values in impedance changes for water flood and lower values in impedance changes for gas breakout.
2.5 Gassmann’s model in matrix-clay mixtures

Gassmann’s model requires that the porous material be isotropic and homogeneous; and in most cases the seismic wavelength is large enough compared to the grain and pore sizes to fulfil these criteria. Quite often the natural sediments are mixtures of matrix and clay components; even assuming that these components are distributed homogeneously in the rock frame, the variability of minerals and frame elastic moduli due to variations of proportions of matrix and clay need to be introduced into the Gassmann’s model by replacing the multi-mineral mixture with an effective elastic medium. There are two main approaches to adapt reservoir rocks into Gassmann’s model: one performs matrix-clay mixing prior to fluid substitution and the other after fluid substitution (Figure 2.20).

Mixing before fluid substitution. In this scheme (Figure 2.20b), which is more common, the matrix \( V_{ma} \) and clay minerals are mixed to calculate the effective mineral moduli and effective dry-rock moduli; these values are then implemented in Gassmann’s equations, in conjunction with total or effective porosity.

![Diagram showing mixing before fluid substitution](image)

**Figure 2.20** Fluid substitution in matrix-clay mixtures. (a) four-component rock model, (b) matrix-clay mixing before fluid substitution, (c) matrix-clay mixing after fluid substitution in matrix and clay components.
Mixing after fluid substitution. In this approach (Figure 2.20c), fluid substitution is performed independently in matrix and clay components by assigning the sand porosity (see Section 0) to the matrix ($V_{ma}$) part, and clay porosity to the clay part. The saturated sand and clay components are then mixed using an effective medium theory. It should be mentioned that one can ignore fluid substitution in the clay component by assigning a single value to the wet clay.

Theoretical discussions of the two methods are covered by Gurvich and Carcione (2000). It is concluded that if the distribution of porosity between sand and clay is relatively uniform, the predictions of the two schemes are similar in a porosity range of up to 0.3. They also argued that the second approach (mixing after fluid substitution) is more appropriate in the seismic domain applications, as it fulfils the no-flow state between sand and clay constituents, whereas the first approach (mixing prior to fluid substitution) implicitly takes into account a possible fluid flow between sand and clay components.

Effective medium theories for matrix-clay mixtures. In both approaches above, the matrix-clay mixture should be replaced with an equivalent elastic medium. Mavko et al. (2009) reviewed the different mixing laws, of which the Voigt-Reuss-Hill (VRH) average is the most widely used method. In fact, in a matrix-clay system, the seismic response is influenced by the clay distribution pattern. Specifically, in the case of laminated clay sediments, where the assumption of a homogeneous distribution of sand and clay is violated (Figure 2.21), the VRH average needs to be replaced with Backus (1962) averaging (Equations D-4 and D-5 in Appendix D). Backus averaging requires the
proportion of the laminated clay at each depth to be known. It is difficult to obtain such information at scales smaller than the scale of the logging tools. Core data and thin section analysis can be used to gain information about the clay distribution. Thomas and Steiber (1975) used porosity versus clay volume cross-plot to address this question. However, the proposed solutions for fluid substitution for laminar shales (Skelt, 2004; Katahara, 2005; Dejtrakulwong and Mavko, 2011) are far from being practical in real-life sim2seis applications.

### 2.5.1 Gassmann’s model in matrix-clay mixtures – modelling results and analysis

In this section, both approaches are used in applying Gassmann’s theory in matrix-clay mixtures. Figure 2.22 shows the results of mixing prior to fluid substitution and Figure 2.23 shows the results of mixing after fluid substitution. The VRH law is used in both cases as the mixing law. Comparing Figure 2.22 and Figure 2.23, mixing before fluid substitution is more successful in modelling the velocity logs. It should be noted that in mixing after fluid substitution, sand porosity is used in fluid substitution, and the more scattered results of this method (Figure 2.23) can be attributed to the unrealistically wide range of sand porosity (up to 1). This variation is reflected in the dependence of the dry-rock moduli on porosity. Following these results and considering the ambiguity associated with the definition of sand porosity in matrix-clay mixtures, this approach is not implemented in this thesis. The 4D response of the two approaches is examined in a PEM application to a simulation model from a turbidite field in the North Sea. The lithology distribution and the change in pressure and saturation over a period of production are shown in Figure 2.1 (page 32). The modelling results (Figure 2.24) show that the difference between predictions of 4D changes of the two approaches is around 30%.
### PEM parameters

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**Figure 2.22** Reconstruction of \( V_p, V_s, \rho \) logs based on matrix-clay mixing before fluid substitution (Figure 2.20b) based on effective porosity. The mismatch between the reconstructed and measured \( V_p \) can be attributed to the uncertainties in the petrophysical evaluations or the interpretations of the sonic data.
### PEM parameters, Measured parameters, Modelled elastic logs ($V_p, V_S, \rho$)

**Figure 2.23** Reconstruction of $V_p$, $V_S$, $\rho$ logs based on matrix-clay mixing after fluid substitution (Figure 2.20c) based on effective porosity. In this case, (effective porosity (wet-clay)), fluid substitution is not performed in the clay component. As highlighted with the black arrows, mixing before fluid substitution (Figure 2.22) is more successful in modelling the velocity logs.
Figure 2.24 The percentage of difference in predictions of acoustic impedance changes between two approaches for matrix-clay mixtures (see Figure 2.1 for pressure and saturation changes and the reference case for the impedance changes). In most of water flooded areas, the difference is around 30%. Due to high pore pressure build-up around injector I6, the difference can be up to 70%. (The value $\Delta(\Delta I_p)$ represents the percentage of error in prediction of $I_p$ between the two PEM models; e.g. for $\Delta I_p^2 = 2\%$ and $\Delta(\Delta I_p) = 10\%, \Delta I_p^2 = 2 \pm 0.2\%$).

2.6 Dry-rock characterisation

In Section 2.4.4, a six-step workflow is outlined for fluid substitution using well log data. This workflow does not require characterising the dry-rock moduli; however this approach is only applicable to fluid substitution in the log domain. For PEM applications to sim2seis, dry-rock moduli also need to be modelled. Figure 2.25 confirms (Smith et al., 2003) that if the lithology/porosity dependence of dry-rock moduli is ignored, the porosity dependence from Gassmann’s theory in conjunction with effective medium theories for minerals are not capable of capturing the detailed variability of velocities due to porosity and lithology variations.

All measured dry-rock properties are based on laboratory data and core samples. Studies on dry-rock characterisation can be classified into two categories. The first category concerns the dependence of the dry-rock moduli on intergranular porosity (in short, porosity) (Nur et al., 1998; Pride, 2005; Krief et al., 1990). The second category addresses the dependence of dry-rock moduli on
**Figure 2.25** PEM results for the case in which the dependence of the dry-rock moduli on porosity is ignored. The modelled elastic logs (panel 8-9) show that without including porosity variations in $\kappa_{\text{dry}}$ (panel 6), the porosity term in the Gassmann model cannot capture the observed variations in the velocities.
variations of effective stress. MacBeth (2004) presented evidence of dependence of dry-rock moduli on both porosity and effective stress; however the proposed mathematical expressions do not include porosity variations. In fact, works that introduce a theory to combine both lithology/resivity dependence and changes due to effective stress variations are limited (Dvorkin & Gutirrez, 2002; Lee, 2005; Avseth & Skjie, 2011; Alvarez & MacBeth, 2014). In this thesis, a formulation for dry-rock moduli is adapted from Lee (2005) (Equations 2-6 and 2-8), which captures both the dependence of dry-rock moduli on porosity (Pride, 2005) (Equations 2-7 and 2-9) and changes in effective stress (MacBeth, 2004). The theoretical basis for this relation is the use of excess compliance as a pseudo function to describe all internal weaknesses in the rock, regardless of their origin. The law is fitted to 179 sets of laboratory measurements on unsaturated reservoir core and outcrop sandstones that have low to moderate porosity and a range of clay fractions and cementation. The following equations summarise the dry-rock modelling that is used in this thesis:

\[
\kappa_{\text{dry}} = \frac{\kappa_\infty}{1+E\kappa e^{-\sigma_{\text{eff}}/P_\kappa}} \tag{2-7}
\]

\[
\kappa_\infty = \kappa_m \frac{1-\phi}{1+a\phi} \tag{2-8}
\]

\[
\mu_{\text{dry}} = \frac{\mu_\infty}{1+E\mu e^{-\sigma_{\text{eff}}/P_\mu}} \tag{2-9}
\]

\[
\mu_\infty = \mu_m \frac{1-\phi}{1+a\phi} \tag{2-10}
\]

where \( \kappa_{\text{dry}} \) and \( \mu_{\text{dry}} \) are dry-rock bulk and shear modulus respectively; \( E_\kappa, P_\kappa, E_\mu, P_\mu \) are the rock stress-sensitivity constants from core measurements that define the shape of the stress-sensitivity curves, and \( \kappa_m \) and \( \mu_m \) are the effective mineral bulk and shear modulus, \( \sigma_{\text{eff}} \) is the effective stress and \( a \) is a lithology-dependent parameter. Effective stress is given by \( \sigma_{\text{eff}} = \sigma_{\text{ob}} - aP_{\text{pore}} \), where \( \sigma_{\text{ob}} \) is the overburden stress, \( P_{\text{pore}} \) is the pore pressure, and \( a \) is the Biot’s coefficient. The underlying assumption here is that \( \kappa_{\text{dry}}/\kappa_m = \mu_{\text{dry}}/\mu_m \), which is valid for most of the applications (Smith, 2011). Instead of Lee’s approach of
using single values for $\alpha$ in sand and shale intervals, to take account of the continuous variation of lithology, I employed a multi-linear regression to construct $\alpha$ based on the rock volume fractions:

$$
\alpha = aV_m + bV_{cl} + c\phi ,
$$

(2-11)

where $a$, $b$, $c$ are constants and $V_m$, $V_{cl}$, $\phi$ are the matrix volume fraction, clay volume fraction and porosity respectively. The influence of the dry-rock moduli lithology dependence on the 4D response is demonstrated in a PEM application to a simulation model from a turbidite field in the North Sea. In this exercise, two different PEMs are employed to predict the impedance change due to pressure and saturation variations. The PEM1 considers only the variations of dry-rock moduli with effective stress, whereas the PEM2 additionally incorporates the variations with lithology. As is shown in Figure 2.26, it can be observed that the lithology dependence of dry-rock moduli results in errors of the same order as the 4D response. Some of the rock stress-sensitivity models represent the stress-sensitivity in the form of velocity as a function of effective stress $V_p(\sigma_{eff})$ and not dry-rock moduli $\kappa_{dry}(\sigma_{eff})$. However, the velocity
response to pressure changes is a combined response of fluids and rock frame, and in cases where pressure variation results in a change in fluid phase (e.g. gas breakout), a non-monotonic response in velocity versus pressure can be observed. Therefore, in stress-sensitivity studies, it is more pertinent to work with dry-rock moduli instead of velocities. The majority of studies on rock stress-sensitivity are based on laboratory data and they may not represent the in-situ field scale stress response. Scott (2007) highlights the effect of stress paths on the rock response and the difference between the field and laboratory scales. Fürre et al. (2009) used repeat logs to calibrate the rock stress-sensitivity and reported counterintuitive observations to those based on laboratory measurements. Their result is supported by matching the observed 4D signal using the stress-sensitivity model based on repeat logs (see Section 5.3.2 for details). In Chapter 5, it is shown how sim2seis can be used to check the validity of laboratory-based stress-sensitivity response at the field scale.

Rock stress-sensitivity is a subject of ongoing research. It is commonly accepted that in most clastics, the variation of intergranular porosity under pressure change is negligible. This perception is sustained by the majority of measurements made on clean sand samples. However, Marion et al. (1992) documented a considerable variation of total porosity due to pressure changes on samples with varying clay content (Figure 2.27). Generally, it is observed that the presence of clay intensifies the variation in total porosity due to pressure change. Depending on the proportion of the variation shared by the effective porosity, ignoring this effect may result in erroneous predictions of the 4D signal. Another area that is overlooked in the literature and is not covered in this thesis, concerns the stress-sensitivity of clay or clay-rich sands (e.g. MacBeth and Ribeiro, 2007; Holt et al., 2005). Conventionally, clays are considered to be inactive reservoir material; however, in a case study, HajNasser and MacBeth (2011) were able to justify an observed 4D signature by linking the clays to the pressure diffusion.
Figure 2.27 Changes in total porosity due to pressure variations as a function of clay content based on laboratory measurements (Marion et al., 1992). When the clay volume fraction is less than the pure sand porosity, clay particles fit within the sand pore space and porosity of the mixture decreases linearly with increasing clay volume fraction; when clay volume fraction becomes greater than sand porosity, addition of clay can be accomplished only by expanding the sand lattice. Sand grains become disconnected and porosity of the mixture increases linearly with increasing clay content, due to replacement of sand grains by porous shaley material.

2.7 Density modelling

Density is a well understood and well defined quantity. Compared to velocity, the linear dependence of density on the volume fraction of the rock constituents and their density makes it easier to model the density log (Equation 2-11). In a similar way to velocity modelling, both total and effective porosity models can be adapted for density calculations.

\[ \rho = \sum_{i=1}^{N} \rho_i V_i, \]  

(2-12)

where \( \rho_i \) and \( V_i \) are the density and volume fraction of each constituent respectively.

2.8 Log based optimisation algorithm for PEM calibration

Despite the use of effective medium theories and the simplicity of Gassmann’s model, fluid substitution is an under-constrained problem, and one of the challenges is to set its input parameters \((k_m, \mu_m, k_{dry}, \mu_{dry})\). These values are typically reservoir dependent and the documented default values in lookup
tables give rise to erroneous results. In particular, the elastic properties of clay minerals are widely variable (Mavko et al., 2009). In a similar way to clay parameters but to a more limited extent, a range of values for the elastic properties of the non-clay minerals should also be considered. Smith (2011) attributes this variability to the presence of minerals other than quartz, and to microstructural defects. Simm (2007) used the cross-plot of the normalised bulk modulus ($\kappa_{\text{dry}}/\kappa_m$) versus porosity to QC the initial guess for the moduli of clay minerals. However, this approach is based on trial and error, and the criteria for selection of the appropriate parameters remain ambiguous. In this study, I attempt to overcome those limitations by designing an optimisation algorithm using the theoretical models mentioned earlier in this chapter. The optimisation algorithm is explained in Figure 2.28. The inputs to the algorithm are the volume fraction of the rock components, in-situ acoustic properties of the fluids, and a reasonable range for the density and elastic moduli of the minerals. At each depth, a constrained search is performed through all possible combinations of the input parameters of the PEM, and the modelled velocities and density logs are compared with the measured $V_p$, $V_s$, $\rho$ logs. Finally, the set of input parameters ($\kappa_{\text{clay}}$, $\mu_{\text{clay}}$, $\kappa_{\text{sand}}$, $\mu_{\text{sand}}$ and $\alpha$) associated with the lowest misfit error are used for the implementation of the PEM. The main advantage of this method is that the analysis is performed simultaneously over several wells to capture the most representative values over the reservoir, rather than on a well by well basis. Figure 2.29 shows the results of the optimisation algorithm over an appraisal well in a turbidite reservoir in the North Sea.

It should be stressed that, to avoid bias in the results, it is essential that the input petrophysical evaluation is consistent across the wells. The data editing and identification of unreliable log data is a vital preliminary step prior to any log based PEM evaluation, the details of which are covered in the petrophysics and rock-physics literature (e.g. Smith, 2011; Simm, 2007; Albery, 1994; Walls and Carr, 2001). One of the main issues arises from mud invaded zones, where the log readings cannot be attributed to virgin formation fluids but to mud filtrate (water based or oil based). In these cases the PEM calibration should be based on fluid saturations ($S_{\text{ro}}$) in the mud invaded zone.
I finish this section with an assessment that shows the importance of PEM calibration. Figure 2.30 shows the errors in the 4D predictions if parameters from lookup tables are used instead of calibrated parameters. It is worth mentioning that although some of the values from lookup tables are recommended for the area of study in the West of Shetland Basin, the resulting error is significant and cannot be ignored.

**Data preparation**

- QC of the petrophysical evaluation and sonic data
- Consistent petrophysical rock components
  - $V_m + V_{cl} + V_w + V_{hydro} = 1$
- Choice of interval of interest
- Choice of number of wells

![Diagram showing the steps of data preparation](image)

**Bulk and shear moduli**

- A range of values for bulk and shear moduli of matrix/clay
- Hill average (Eq. D-1)
- MacBeth (2004) & Lee (2005) (Eq. 2-7 - 2-10)
- A range of values for parameter $\alpha$ in Eq. 2-11

**Density**

- A range of values for density of matrix/clay

**Dry-rock**

- Batzle and Wang (1992) equations
- Fluid mixing (Eq. 2-3 or 2-5)

**Fluid**

- Gassmann’s equations (Eq. 2-1 & 2-2)

**Fluid Substitution**

- Batzle and Wang (1992) equations
- Density calculation (Eq. 2-12)

Saturated $V_p, V_s$ and Density

Calculate the misfit between the modelled and measures $V_p, V_s$, and Density

Choose the best values for bulk modulus, shear modulus, density of the matrix and clay, and the best values of parameter $\alpha$.

**Figure 2.28** PEM optimisation algorithm. The input data preparation, the equations for modelling $V_p, V_s, \rho$ logs are explained. The input parameters that should be provided by the user are marked in red.
### PEM parameters

- **Matrix**
- **Dry Clay**
- **Wet Clay**
- **CBW**
- **CAP+FW**
- **Hyd**

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### Figure 2.29
Log based PEM calibration. The PEM model is based on using matrix-clay mixtures (Voigt-Reuss-Hill) before fluid substitution using Gassmann’s model. Equations 2.6 to 2.9 are used for dry-rock characterisation. The orange dots in panel 7 are the optimised values for parameter α in Equations 2.7 and 2.9. The black curve in panel 7 shows the multi-linear regression curve for α (Equation 2.10).
Figure 2.30 The error in the prediction of the changes in acoustic impedance if parameters from lookup tables are used instead of calibrated parameters (see Figure 2.1 for pressure and saturation changes and the reference case for the impedance changes). The error is of the same magnitude as the 4D signal and cannot be ignored. (The value $\Delta(\Delta I_p)$ represents the percentage of error in prediction of $\Delta I_p$ between the two PEM models; e.g., for $\Delta I_p^x = 2\%$ and $\Delta(\Delta I_p) = 10\%$, $\Delta I_p^x = 2 \pm 0.2\%$).

2.9 Summary

This chapter has presented the development of the petro-elastic model in the petrophysical domain based on well-log data. Different aspects of Gassmann’s fluid substitution model in heterogeneous matrix-clay systems were studied. In Section 2.3, it was observed that pressure sensitivity of the acoustic properties of the fluids has a negligible effect on the 4D predictions. In an application to the simulation model from a North Sea turbidite reservoir, harmonic averaging (Domenico, 1974) and the fluid mixing equation proposed by MacBeth and Stephen (2008) were compared. Because the simulation model in this study was rather fine scale ($dz \approx 3m$), the predictions of both approaches were similar. In section 2.4, the basic, yet sometimes ill-defined concept of porosity was elaborated in the context of fluid substitution in heterogeneous matrix-clay systems. Three porosity choices, (total, effective, and movable fluid models) were adapted for Gassmann’s model. It was observed that total porosity predicted a larger softening due to gas breakout and smaller values for a water flood; whereas the movable fluid model predicted smaller softening due to gas breakout and larger values for water flood. Effective porosity predictions remained between the total porosity and movable fluid models. As shown in
Figure 2.18, the differences between these models are due to the different proportion of fluids that are mixed in each case to be used in Gassmann equations. It is also observed that dry-rock characterisation is challenging in the movable fluid model. In Section 2.5, two models for adapting the Gassmann’s model to matrix-clay mixtures were studied. The model based on matrix-clay mixing before fluid substitution was compared with the matrix-clay mixing after fluid substitution. The model based on mixing after fluid substitution considers matrix and clay components as two separate entities, which makes it difficult to include variations in dry-rock properties in the presence of heterogeneity, and therefore it is not used in this thesis. In Section 2.6, the importance of dry-rock characterisation in PEM predictions was highlighted; it was shown that to reconstruct velocity logs it is necessary to include the dependence of dry-rock properties on porosity and lithology variations. It is also shown that an oversimplification of the dry-rock characterisation, in which only changes due to effective stress variations are considered can lead to errors of the same magnitude as those in the 4D seismic signal. Therefore, MacBeth’s (2004) stress-sensitivity model and Pride’s (2005) model were combined to capture both lithology/porosity dependence and variations of the dry-rock elastic moduli with changes in the effective stress. Finally, the importance of calibration of the parameters in the Gassmann model was emphasised. In particular, clay parameters are highly variable and care must be taken in assigning the matrix and dry-rock parameters in matrix-clay mixtures. To overcome this challenge, an optimisation algorithm has been designed that captures the variations of dry-rock properties with lithology and porosity and allows for choosing the best set of PEM parameters. One of the uncertainties associated with well-based PEM concerns the applicability of PEM away from well locations. It is important to ensure the capture of the variations in lithology, sedimentology, minerals and fluids across the reservoir. Including several wells across the reservoir helps to reduce such uncertainties.
CHAPTER 3

A Suitable Petro-elastic Model for Sim2seis: Simulation Model Perspective
3.1 Introduction

In Chapter 2, the development of the PEM in the petrophysical domain was described and the influence of the different rock components on the 4D seismic response is examined. As mentioned previously, an essential criterion of a suitable PEM for sim2seis is its applicability to the simulation model. Petrophysicists look at rocks through mineralogy, grain size and sorting, fluid content, etc., whereas, the engineers’ grasp of porosity and other rock constituents is defined within a fluid flow perspective. It is therefore very important to understand the definition of the parameters in the engineering domain and establish the underlying relationship with the petrophysical domain. This allows for the same formulation to be developed in the petrophysical domain and applied to the parameters in the simulation model.

The logs from exploration and appraisal wells are commonly targeted at good quality reservoirs (sweet spots). Simulation models represent upscaled versions of the geological models (or log data). Upscaling decreases the heterogeneity, and if the simulation model is coarsened too far, the reservoir description may be overly homogenised (King et al., 2006).

![Figure 3.1](image)

**Figure 3.1** Histograms of the clay-bound water ($V_{cbw}$) variations in the reservoir show the difference in lithology variations between log data and reservoir model in the interval T31 of the Schiehallion model (see Figure 3.2). High quality reservoir ($V_{cbw} < 0.05$), medium quality reservoir ($0.05 < V_{cbw} < 0.1$), and lower quality reservoir ($0.1 < V_{cbw}$).
Figure 3.2 Lithology variations in the interval T31 in the Schiehallion model; (a) rock constituents in well-log domain, (b) net-to-gross in the reservoir model.
Figure 3.3 The schematic 1D cell representation of the simulation model.

\[
div\left(\frac{k_o}{\mu_o B_o} (\nabla p_o - \rho_o g \nabla z)\right) = \frac{\partial}{\partial t} \left(\phi \frac{s_o}{B_o}\right) + Q_o \quad (3-1a)
\]

\[
div\left(\frac{k_g}{\mu_g B_g} (\nabla p_g - \rho_g g \nabla z)\right) + \frac{R k_o}{\mu_o B_o} (\nabla p_o - \rho_o g \nabla z) = \frac{\partial}{\partial t} \left(\phi \frac{s_o}{B_o} + \frac{s_i^g R}{B_o}\right) + Q_{fg} + R Q_o \quad (3-1b)
\]

\[
div\left(\frac{k_w}{\mu_w B_w} (\nabla p_w - \rho_w g \nabla z)\right) = \frac{\partial}{\partial t} \left(\phi \frac{s_w}{B_w}\right) + Q_w \quad (3-1c)
\]

\[
p_o - p_w = p_{ow}(s_g, s_o, s_w) \quad (3-1d)
\]

\[
p_g - p_w = p_{go}(s_g, s_o, s_w) \quad (3-1e)
\]

\[
s_g + s_o + s_w = 1 \quad (3-1f)
\]

\[
\left[\begin{array}{c}
T_{o}^{i+0.5jk} (p_o^{i+1jk} - p_o^{i-1jk}) - T_{o}^{i-0.5jk} (p_o^{i-1jk} - p_o^{i+1jk})
\end{array}\right]^{n+1} - \\
\left[\begin{array}{c}
T_{o}^{i+0.5jk} g(z^{i+1jk} - z^{i+1jk}) - T_{o}^{i-0.5jk} g(z^{i-1jk} - z^{i+1jk})
\end{array}\right]^{n+1} + \\
\left[\begin{array}{c}
T_{o}^{ij+1jk} (p_o^{ij+1jk} - p_o^{ij+1jk}) - T_{o}^{ij-0.5jk} (p_o^{ij-0.5jk} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \\
\left[\begin{array}{c}
T_{o}^{ij+0.5k} g(z^{ij+1jk} - z^{ij+1jk}) - T_{o}^{ij-0.5k} g(z^{ij-0.5jk} - z^{ij+1jk})
\end{array}\right]^{n+1} + \\
\left[\begin{array}{c}
T_{o}^{ij+0.5k} (p_o^{ij+1jk} - p_o^{ij+1jk}) - T_{o}^{ij-0.5k} (p_o^{ij-0.5k} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \\
\left[\begin{array}{c}
T_{o}^{ij+1jk+0.5} g(z^{ij+1jk} - z^{ij+1jk}) - T_{o}^{ij+0.5k} g(z^{ij+1jk} - z^{ij+1jk})
\end{array}\right]^{n+1} + \\
\left[\begin{array}{c}
T_{o}^{ij+1jk} (p_o^{ij+1jk} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \left[\begin{array}{c}
T_{o}^{ij-0.5k} (p_o^{ij-0.5k} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \\
\left[\begin{array}{c}
T_{o}^{ij+0.5k} (p_o^{ij+1jk} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \left[\begin{array}{c}
T_{o}^{ij-0.5k} (p_o^{ij-0.5k} - p_o^{ij+1jk})
\end{array}\right]^{n+1} - \\
\left[\begin{array}{c}
T_{o}^{ij+1jk+0.5} g(z^{ij+1jk+0.5} - z^{ij+1jk}) - T_{o}^{ij+0.5k} g(z^{ij+1jk+0.5} - z^{ij+1jk})
\end{array}\right]^{n+1} + \\
\left[\begin{array}{c}
T_{o}^{ij+1jk} (p_o^{ij+1jk} - p_o^{ij+1jk})
\end{array}\right]^{n+1} + \left[\begin{array}{c}
T_{o}^{ij+0.5k} (p_o^{ij+1jk} - p_o^{ij+1jk})
\end{array}\right]^{n+1} + Q_{oij}^{n+1} \quad (3-2a)
\]

\[
T_{l}^{i+0.5jk} = \frac{S_{l}^{i+0.5jk}}{\Delta x_L} \left(\frac{k_{xk}}{\mu_L B_L}\right)_{ij+0.5jk} \quad (3-2b)
\]

\[
T_{l}^{ij+0.5k} = \frac{S_{x}^{ij+0.5k}}{\Delta x_L} \left(\frac{k_{xk}}{\mu_L B_L}\right)_{ij+0.5k} \quad (3-2c)
\]

\[
T_{l}^{ij+0.5k} = \frac{S_{y}^{ij+0.5k}}{\Delta y_L} \left(\frac{k_{yk}}{\mu_L B_L}\right)_{ij+0.5k} \quad (3-2d)
\]
Thus, compared to well-log data, simulation models generally include more lateral variability in the lithologies, and in general, a considerable proportion of the reservoir models consists of medium quality reservoir rocks (clay-rich sands) and non-reservoir material (that is, inactive cells) (Figure 3.1 and Figure 3.2). The seismic signature of the 4D signal is influenced by the architecture and properties of non-reservoir rocks relative to the reservoir rocks; i.e. a part of the geological footprint on the 4D signal is linked to non-reservoir rocks. Thus, characterising the elastic properties of the inactive cells should not be ignored in the application of the PEM to the simulation models. Examination of the elastic properties of the inactive intervals in different wells across the reservoir or incorporating the seismic inversion helps us to understand the potential variability within the inactive cells. Another difference between petrophysical and engineering domains is the difference in the vertical scale between well-log data and the reservoir model. The cells in the reservoir model are a blocky representation of the reservoir, and each cell represents the average properties within the same volume. This results in a different seismic response between log and simulation model scales. This issue has been addressed in the literature by introducing the so-called scale-dependent PEM methods (Menezes and Gosselin, 2006; Alfred et al., 2008); however, as will be explained in this chapter, these methods are not suitable for sim2seis modelling.

3.2 The rock model for the simulation model

Similarly to the petrophysics domain, where the definitions of the components of the rock model were explained in the previous chapter, the rock model and its constituents in the engineering domain needs to be described. For example, it needs to be investigated how the volume of matrix or the volume of clay are utilised in the simulation model. In this section, by going through the fluid-flow equations in the simulator, the quantities that represent the rock components are tracked, and the rock model dictated by those equations is explored. In the mathematical model for fluid-flow equations (Equation 3-1), porosity ($\phi$) is the only term that represents the rock model. To obtain an insight into the origin of porosity in these equations, it is worth reviewing how they are derived. The schematic 1D representation of the simulation model is shown in Figure 3.3.
Initially, the pore volume of each cell ($\phi \cdot Vol$) exists in the equations. Pore volume is the volume fraction of each cell that is available for fluid flow. The geometric volume ($Vol$) of each cell is then decomposed into area and length terms; area terms are cancelled from both sides of the equations, and the length terms are hidden in the spatial derivative operators, such that, in the final representation of the equations, the geometric volume cannot be seen and only porosity is left. However, in the numerical solution of these equations (as they are used in simulators such as Eclipse) (Equation 3-2), the geometric volume ($V_{ijk}$) appears again and, together with porosity ($\phi V_{ijk}$), they represent the pore volume. In the Eclipse simulator, to adapt this concept to the heterogeneous reservoir rocks, effective pore volume is introduced using the net-to-gross ratio $NTG$.

$$PV_{eff} = NTG \cdot \phi \cdot Vol$$  \hspace{1cm} (3-3)$$

where $PV_{eff}$ is the effective pore volume, $NTG$ represents heterogeneity and is net-to-gross thickness ratio, $\phi$ is porosity and $Vol$ is the geometric volume of each cell. The $NTG$ and porosity concepts in the simulation model will be discussed later in more details. The key message here is that neither porosity nor $NTG$ are present in the fluid flow equations as independent and explicit

\[
PV = (dx dy dz) \cdot NTG \cdot \phi_{ecl} \quad \text{NTG: net to gross thickness ratio} \quad PV = (dx dy (dz \cdot NTG)) \cdot \phi_{ecl}
\]

\[
\begin{align*}
\text{dv} \\
\text{dx} \cdot \text{dy} \cdot \text{dz} = 1
\end{align*}
\]

\[
\begin{array}{c}
\text{NTG} \\
(1 - \text{NTG})
\end{array}
\]

\[
\begin{array}{c}
\text{NTG} \cdot \phi_{ecl} \\
\text{NTG} \cdot (1 - \phi_{ecl}) \\
(1 - \text{NTG})
\end{array}
\]

\[
\text{three components of the rock model in the simulation domain}
\]

**Figure 3.4** Rock model in the simulation model. Pore volume definition in the simulation model (Equation 3-3) implies a three-component rock model.
parameters; what matters is the effective pore volume. As illustrated in Figure 3.4, Equation 3.3 implies a three-component rock model in the simulation model. The links between these three components and the petrophysical rock models are discussed in Section 3.2.3.

3.2.1 Porosity from engineer’s perspective

Following the definition of porosity in the petrophysical domain from the previous chapter, porosity is now outlined from the engineer’s viewpoint. As with most engineering data, such as relative permeability and capillary pressure curves, the engineer’s grasp of porosity is determined by porosity measurements on core samples. Core porosity measurements are performed using different approaches, each of which measure different types of porosity. Methods such as imbibition, mercury injection and gas expansion are designed to give the connected porosity, whereas other methods such as the direct method, density methods, or petrographic methods give the total porosity. Engineers typically refer to the connected porosity as effective porosity; however, as mentioned in the previous chapter, in the definition of the log-derived total/effective porosity there is no reference to the need for the porosity to be connected. Moreover, it is noted that retaining clay-bound water in the laboratory is difficult; therefore laboratory porosity measurements are generally linked to the log-derived total porosity (Prammer, 1996). It should be noted that, if the core samples are taken from clean reservoir intervals, where the clay content (and hence the clay-bound water) is minimal, total porosity would be equivalent to effective porosity. From the fluid flow viewpoint, the pore space is limited by capillary-bound fluids. In simulation models, the saturation end members based on relative permeability curves are implemented to take the capillary-bound fluids into account.

3.2.2 Net-to-gross ratio (NTG)

In formation evaluation, the net-to-gross ratio (NTG) is a generic term used to delineate the depth intervals at which hydrocarbons are economically producible (Worthington and Cosentino, 2003). Generally, it is the ratio of net thickness to
Figure 3.5 Schematic inter-relationship of net parameters with cut-off applied sequentially (Worthington and Cosentino, 2003).

Gross thickness. Binary $NTG$ is determined based on cut-offs – either net sand, net reservoir or net pay – and expressed as net-to-gross sand, net-to-gross reservoir or net-to-gross pay, respectively. Figure 3.5 shows these concepts schematically by sequential application of cut-offs. Although this is often missed, when referring to $NTG$, the basis for its definition should be addressed. Continuous $NTG$ based on indirect calculations or a direct measurement (nuclear magnetic resonance (NMR)) is also a recent method for reservoir evaluation.

In practice, different methods can be used to distribute $NTG$ as a property into the reservoir grid. Based on the current capabilities of geomodelling software packages, what follows are the recipes for $NTG$ modelling:

1) If no facies model exists, the $NTG$ map can be used to distribute $NTG$ between top and base of the evaluation interval. Alternatively, after effective porosity modelling, a cut-off is set on porosity such that $NTG$ for cells with porosity higher than cut-off value is set to 1, and for the rest $NTG$ is set to 0.
2) If a facies model exists, facies are separated into reservoir and non-reservoir, and the $NTG$ in reservoir facies is set as 1 and in the non-reservoir facies to 0. Different rock types can be classified into different facies types with different $NTG$ values, e.g. channel axes have a higher $NTG$ whereas levees have a lower $NTG$.

3) $NTG$ can also be built using either a log of the binary reservoir flag or a continuous log of clay volume where $NTG$ is set equal to $1 - V_{cl}$. In this case, no other cut-offs should be used (e.g. on $\phi_e$) to separate non-reservoir rocks. $NTG$ will reduce the pore volume regardless of reservoir or non-reservoir rocks (Equation 3-3).

Currently, the way that the heterogeneities are embodied in $NTG$ is very simplistic. Figure 3.6 illustrates two cells of the reservoir model with dispersed and laminar clay distributions. Assuming equal $V_{cl}$ in both cases, and considering a continuous $NTG$ definition equal to $1 - V_{cl}$, $NTG$ in both cases would be equal. Nevertheless, these cases clearly have different flow characteristics. Engineers can adjust the vertical permeability versus horizontal permeability ($k_v/k_h$) to take into account the effect of clay distribution from the fluid flow perspective. Due to the differences in geometry of the distribution of clays in the matrix, the seismic response of these cases is also expected to be different. However, only pore volume fraction and clay volume fraction contribute to the PEM calculations. Since the clay distribution is not reflected in these quantities, the seismic response of both cases will incorrectly be identical. The Thomas-Stieber (1975) plot in Figure 3.7 shows that the shaly sands in the Schiehallion T31 interval are comprised of both laminar and dispersed clays. However, following the satisfactory results based on the dispersed clay model in Figure 2.22, this assumption is applied to the sim2seis calculation.
Figure 3.6 Limitations of NTG in capturing the reservoir heterogeneity in two different cases of clay distribution. Considering a continuous NTG definition equal to $1 - V_d$, NTG in both cases would be equal. Nevertheless, each case has different flow characteristics and seismic responses.

Figure 3.7 Porosity versus shale volume in the Thomas-Stieber plot. The yellow circle represents shaly sands in T31 interval which are a combination of laminar and dispersed shale. The yellow circle can be interpreted as a laminar sequence where the 25% of the interval consists of laminar shale, and dispersed clay fills 25% of the pore space in the sand layer.
Figure 3.8 NTG in transmissibility calculations (Equation 3-4). NTG in each cell is used to calculate the effective area and transmissibility between the two cells.

On a separate note, as well as the pore volume calculations, $NTG$ is also used in the simulation model to compute the effective area between two neighbouring cells for transmissibility calculations (Figure 3.8):

\[
T_x = (c \cdot TM_i \cdot D)/B \quad \text{(3-4a)}
\]

\[
A = (dx_idy_idz_iNTG_i + dx_idy_jdz_jNTG_j)/(dx_i + dx_j) \quad \text{(3-4b)}
\]

\[
B = \left(\frac{dx_i}{kx_i} + \frac{dx_j}{kx_j}\right)/2 \quad \text{(3-4c)}
\]

where $c$ is the Darcy’s constant, $TM_i$ is the transmissibility multiplier for cell $i$, $D$ is dip correction, and $kx_i$ is the permeability in the $x$ direction for cell $i$. This means that $NTG$ is common to both pore volume and transmissibility calculations. However, using NTG to reduce both pore volume and transmissibility without considering the geometry of the clay distributions in the matrix does not seem to be logical. Following the discussion above, one of the areas that need further development in the engineering domain is the treatment of the geological heterogeneities in the simulation model. Currently, different factors generically categorised as ‘multipliers’ (transmissibility multiplier, pore volume multiplier, etc.) are in use in the simulator to compensate for potential shortcomings of this approach in emulating reality.
3.2.3 Petrophysical versus simulation rock model

In this section, the link between the petrophysical and engineering domains is established. As discussed above, NTG is a key parameter in defining components of the rock model in the simulation model (Figure 3.4), and can be linked to \( 1 - V_{ct} \). In the petrophysical domain, effective porosity can be approximated as a function of total porosity as: \( \phi_e = (1 - V_{ct})\phi_t \). These relations are summarised as follows:

- \( PV = NTG \cdot \phi_{ecl} \) (simulation model)
- \( NTG = 1 - V_{ct} \) (simulation model)
- \( \phi_e = (1 - V_{ct})\phi_t \) (petrophysical domain)

where \( \phi_{ecl} \) is the porosity in the Eclipse simulation model. Considering these relations, it is more sensible to use effective porosity to translate the rock model in the simulation model to the petrophysical rock model.

Table 3-1 summarises the link between the parameters in the two domains. Care must be taken when using these equations, because the choice of cut-offs in the NTG definition (Worthington and Cosentino, 2003; Menezes and Gosselin, 2006) complicates the equations in Table 3-1. The equations in this table highlight the conceptual differences between the petrophysical definition of porosity and the porosity in the simulation model; in other words, the pore volume (not the porosity) in the simulation model is the corresponding quantity for petrophysical effective porosity. Hence, in sim2seis calculation, which integrates the petrophysical and simulation model parameters, care must be taken to ensure that the simulation model porosity correctly represents the effective porosity in the PEM.

<table>
<thead>
<tr>
<th>Petrophysics volume fractions</th>
<th>Simulation model volume fractions</th>
</tr>
</thead>
<tbody>
<tr>
<td>( V_{ct} )</td>
<td>( 1 - NTG )</td>
</tr>
<tr>
<td>( \phi_e )</td>
<td>( NTG \cdot \phi_{ecl}^* )</td>
</tr>
<tr>
<td>( 1 - V_{ct} - \phi_e )</td>
<td>( NTG \cdot (1 - \phi_{ecl})^* )</td>
</tr>
</tbody>
</table>

*porosity in Eclipse model

**Table 3-1** Definitions of rock models between petrophysics domain and simulation models.
Following the discussions so far, I would like to stress the importance of consistency between the petrophysical evaluations and property distributions in the geological model. One should contemplate that the reservoir model might be used for sim2seis analysis (or closing the loop purposes). Thus, as well as satisfying fluid flow conditions, the model should be suitable for PEM workflows. Therefore, using a different variety of multipliers or cut-offs in the simulation model that cannot be translated into PEM calculations is not favourable.

3.3 PEM at log domain versus PEM at simulation model

In Chapter 2, the porosity concepts in fluid substitution were reviewed. The modelling results based on total/effective porosity are shown in the log domain (Figure 2-12) and the simulation model (Figure 2-16). The histogram of the 4D prediction for water flooding based on total and effective porosity models in the two domains are shown in Figure 3.9. Firstly, it is observed that the well-log

![Figure 3.9](image)

**Figure 3.9** Histogram of the percentage of changes in acoustic impedance due to water flooding in the log domain versus the simulation model. Solid and dashed curves show the histograms for the log and simulation domains respectively. The red and blue curves show the histograms for the effective and total porosity models respectively. Although the effective and total porosity models give very similar results in the log domain, there is a difference between the two porosity models in the simulation domain (marked by black double-ended arrow). The impedance change in the simulation model goes just over than 4%, whereas in the log domain it goes up to 8%. This difference (marked by grey arrows) is related to the different saturation changes in the two domains; while all the movable oil is replaced by water in the log domain, the oil in the simulation model is not fully substituted with water.
calculations predict higher values of impedance changes compared to predictions from the simulation model. This is because in the log domain, 4D changes are calculated by substituting oil with maximum water saturation \(1 - S_{or}\), whereas the majority of the cells in the simulation model are not fully swept, which results in lower changes in the impedances. However, the significance of this plot is not the difference between the ranges of predictions of the two domains, but the difference between predictions based on total and effective porosity models in the two domains. While the predictions based on effective and total porosity in the log domain are almost identical, the predictions in the simulation model offer different values of 4D changes. This is due to the differences in the lateral variability in the properties between log domain and simulation model.

In the well that is used in this work, the reservoir intervals that contain the majority of 4D changes have minimal clay-bound water (Figure 2-12); hence, total porosity is equivalent to the effective porosity, which results in similar histograms of the changes for the two porosity models. On the other hand, a considerable portion of cells in the reservoir model (Figure 3.10) are clay-rich sand (with medium to high values of clay-bound water), in which total and effective porosity differ, resulting in different predictions of each porosity basis. In the case where the wells that are used for PEM analysis consist of wells that are targeted on sweet spots, PEM analysis tends to be biased toward good quality reservoir rocks. Quite often, clay-rich intervals are overlooked in PEM analysis in the log domain (Simm, 2007, Figure 3.11); however, as shown here, characterising clay parameters is essential to predicting the 4D signature in medium quality reservoir rocks in the simulation model. The proposed algorithm for PEM calibration in the previous chapter includes the lithology variations and is therefore suitable for characterising medium quality and non-reservoir rocks.
Figure 3.10 Lateral variability in the reservoir model. A high proportion of the cells in the reservoir are clay-rich sand with medium ($0.05 < V_{cbw} < 0.1$) to high values of clay-bound water ($0.1 < V_{cbw}$); (a) total porosity, (b) effective porosity, (c) clay-bound water.
Figure 3.11 Fluid substitution exercise in matrix-clay mixtures. Red boxes highlight the clay-rich intervals that are excluded from fluid substitution analysis (Simm, 2007)

3.4 PEM and vertical upscaling

In an integrated sim2seis study, four different vertical scales are dealt with: log scale, geological model scale, simulation model scale, and the seismic scale (Figure 3.12). The simulation model is intended to be an equivalent coarse scale representation of the geological model, with similar fluid flow characteristics. If upscaling is done properly, it preserves both the fluid flow patterns and the geological representation of the reservoir at a larger scale; however the seismic response at each scale will invariably be different. Scale-dependent PEMs are introduced in an attempt to address this issue by adjusting the PEM parameterisation at each scale, to preserve the seismic response. In this section, by evaluating the effect of upscaling on the seismic response, different aspects of these methods and their shortcomings are investigated.
3.4.1 Geologically consistent upscaling and scale-dependent PEM

Alfred et al. (2008) attribute the upscaling error to the mixing of lithologies. However, even in a geologically consistent upscaling, in which mixing between major sand and shale intervals is avoided, errors still arise, due predominantly to distortions of the reflectivity series after upscaling. Figure 3.13 shows five different vertical scales: $S_1$ is the log scale, $S_2$ is the scale at geological model, and scales from $S_3$ to $S_5$ are three different upscaled models in which a number of geomodel cells are grouped vertically together to generate the larger scales. To stay geologically consistent and avoid mixing the sand and shale intervals, a cut-off is set prior to upscaling at the geological model scale, and major sand and shale intervals are separated. The configuration of these major intervals is conserved during upscaling. The PEM parameters are set according to the optimisation algorithm (Section 3.2.6) at the log scale, and the same parameters are applied to calculate the $V_p$, $V_s$, and density logs at all scales. This is followed by calculation of the synthetic seismograms for cases $S_1$ to $S_5$. Figure 3.14 shows the results, where, by moving towards the larger scales, the seismic response becomes more deviated from the response of the log scale. This has an undesirable effect on the amplitude analysis of the seismic response at larger scales.
Figure 3.13 Geologically consistent property upscaling. S1 represents the log scale. S2 shows the reservoir model scale. In scales S3 to S5, different numbers of layers in the simulation model are grouped together to generate the larger scales. The sand/shale intervals are prevented from mixing during this process.

Figure 3.14 The seismic response at different scales. Grey traces show the seismic response at log scale. Blue traces show the corresponding seismic response to the different scales in Figure 3.13. By moving towards the higher scales, the seismic response becomes more deviated from the response of the log scale.
To reduce the adverse effect of upscaling on PEM and the seismic response predictions, scale-dependent PEM is introduced (e.g. Menezes and Gosselin, 2006; Alfred et al., 2008). In this workflow (Figure 3.15), the $V_P$, $V_S$, and density logs are upscaled to the desired larger scale using a Backus average. The Backus averaged logs are considered as the truth at the larger scale. In the next step, the PEM at the larger scale is adjusted to match these logs. However, from the sim2seis point of view, the pseudo-logs that are extracted from the simulation model are blocked. The boundaries between the blocks are defined by the reservoir grid, and therefore, unlike the Backus averaged logs that look smooth at larger scales, the pseudo-logs are not smoothed but blocked. Once the logs are blocked, their seismic response will change because the reflectivity series will be limited to the number and position of the block interfaces in the reservoir grid. To show this effect in a sim2seis application, the sequence of application of PEM and upscaling is reversed in cases S1 to S5. In this approach, $V_P$, $V_S$, and density logs are calculated at the scale of the geological model, and then mapped to the larger scale using Backus averaging. Figure 3.16 compares the results of the two approaches. The difference between the two approaches in the seismic domain is negligible and both deviate from the seismic response at log-scale. Therefore due to the blockiness of pseudo-logs in the simulation model, the Backus average is not applicable to create the truth case at larger scales. Consequently, one of the main assumptions and hence the practicality of scale-dependent PEMs at higher scales is uncertain in sim2seis applications.
Figure 3.16 The seismic response at different scales. Grey traces show the seismic response at log scale. Blue and red traces show the corresponding seismic response to the different scales in Figure 3.13. Blue traces are the results of property upscaling followed by PEM application. Red traces show the results of the PEM application followed by upscaling of $V_r$, $V_s$, rho using Backus averaging. It should be noted that red and blue traces nearly overlap.

3.4.2 Property upscaling versus reflectivity upscaling

Up to this point, the effect of upscaling on the seismic response has been illustrated. In fact, the change in seismic signature at each scale is due to the change in the corresponding reflectivity series. Although the major geological and engineering features are preserved in an ideal upscaling, the reflectivity will not be upscaled correctly. To make the concept of reflectivity upscaling clearer, the following question should be addressed: “What does an upscaled rock model that preserves the seismic signature look like?” To answer this question, an inversion algorithm based on the PEM is designed. The inversion engine is based on simulated annealing (Tian and MacBeth, 2013) (See Appendix E for more detail). The algorithm is modified to embed the PEM equations into the inversion calculations (Figure 3.17). In this algorithm, instead of inverting for seismic impedance, the output of the inversion is a rock model at the larger scale that preserves the seismic signature. The inputs to this algorithm are: 1) the frame of the upscaled simulation grid, in depth, 2) the reasonable bounds for
pore volume and volume of clay from the petrophysical analysis, 3) the wavelet from the well-tie at the log-scale and 4) the seismic response at log scale to calculate the misfit function. In each iteration, firstly the parameter space (pore volume and volume of clay) is perturbed within the upscaled grid frame. Next, the PEM equations are applied to calculate the $V_p$, $V_s$ and density logs. The velocity logs are used to perform depth to time conversion. Then the wavelet (from well-tie at log-scale) is used to generate the seismic response, and finally the misfit between the seismic response of the upscaled model and the seismic response at the log scale is calculated. This procedure is performed iteratively until a good match between the seismic responses at the two scales is achieved. The outcome of the inversion is an upscaled model that generates the closest seismic response to that of the log scale using the same PEM, in other words this is a model that appropriately creates an upscaled reflectivity. The results of reflectivity upscaling for scales S2-S5 are shown in Figure 3.18 to Figure 3.21. This algorithm can be used to close the loop between the 3D seismic and reservoir model to update the parameters in the reservoir model. In such applications, as mentioned in Chapter 2, the applicability of the well-based PEM away from well locations should be addressed.

![Figure 3.17](image)

**Figure 3.17** The workflow for reflectivity upscaling. The input to the algorithm is the seismic response at log scale, and the reservoir grid at larger scale. The outcome of the inversion is an upscaled model that generates the closest seismic response to that of the log scale, using the same PEM as the log scale. The parameter space is the pore volume and NTG.
Figure 3.18 Reflectivity upscaling versus property upscaling for scale $S_2$. (a) rock model at log scale, (b) rock model constituents at scale $S_2$ from property upscaling, (c) rock model constituents at scale $S_2$ from reflectivity upscaling (inversion), (d) seismic response at log scale in grey, seismic trace from the property upscaling in blue, seismic trace from reflectivity upscaling (inversion) in green.

Figure 3.19 Reflectivity upscaling versus property upscaling for scale $S_3$. (a) rock model at log scale, (b) rock model constituents at scale $S_3$ from property upscaling, (c) rock model constituents at scale $S_3$ from reflectivity upscaling (inversion), (d) seismic response at log scale in grey, seismic trace from the property upscaling in blue, seismic trace from reflectivity upscaling (inversion) in green.
Figure 3.20 Reflectivity upscaling versus property upscaling for scale $S_b$. (a) rock model at log scale, (b) rock model constituents at scale $S_b$ from property upscaling, (c) rock model constituents at scale $S_b$ from reflectivity upscaling (inversion), (d) seismic response at log scale in grey, seismic trace from the property upscaling in blue, seismic trace from reflectivity upscaling (inversion) in green.

Figure 3.21 Reflectivity upscaling versus property upscaling for scale $S_b$. (a) rock model at log scale, (b) rock model constituents at scale $S_b$ from property upscaling, (c) rock model constituents at scale $S_b$ from reflectivity upscaling (inversion), (d) seismic response at log scale in grey, seismic trace from the property upscaling in blue, seismic trace from reflectivity upscaling (inversion) in green. Although the rock model from reflectivity upscaling preserves the seismic response it does not properly represent the geology at larger scale. Porosity in interval (A) is overestimated in the model from inversion, whereas the volume of matrix is underestimated in interval (B).
Figure 3.21 shows the inversion results for scale $S_n$. It is interesting to compare the rock models from property upscaling and reflectivity upscaling. Compared to the model from property upscaling, in the model from reflectivity upscaling, in interval (B) the sand portion of rock has decreased, and in interval (A) the porosity has increased. Therefore, although the resultant model from reflectivity upscaling preserves the seismic response, it does not necessarily represent the geology at the coarser scale. In addition to the implications for sim2seis analysis, this has implications for inverting the seismic for properties on the reservoir grid at larger scales. In other words, the effect of the scale may disguise the true geological features in the reservoir model. The dilemma of simultaneously preserving both the geological features and seismic response at larger scales is demonstrated here. It appears that the best suggestion is to avoid working with an upscaled model wherever possible, or to perform a sensitivity analysis to find the largest scale that is safe enough to work with.

### 3.5 Summary

PEM equations are generally developed in the petrophysical domain. The applicability of these equations to the simulation model for sim2seis analysis should be addressed. In this chapter, the inherent differences between the petrophysical and engineering domains have been discussed. The parameters that represent the rock constituents in the simulation model were extracted from fluid flow equations and a three-component rock model was constructed accordingly. Pore volume and net-to-gross (NTG) are two key parameters in establishing the link between the simulation model and petrophysical domain. Following the definition of pore volume and NTG in the simulation model, the petrophysical effective porosity was found to be the best model to establish the relationship between the two domains. Therefore, it is recommended to develop and calibrate the PEM in the petrophysical domain based on the effective porosity model. If the total porosity is included at the geological model building stage, clay-bound water should be estimated across the reservoir, to calculate the irreducible water saturation and the pore volume fraction. The differences in lithology variations between well-log data and reservoir models were also highlighted. It is mentioned that log-based PEM might be biased toward good
quality reservoir rock. However, the lower quality reservoir rocks (clay-rich rocks) may comprise a considerable portion of the reservoir models. Therefore, one should not overlook calibration of the PEM in lithologies that depict low 4D responses in the well log domain. Well log data may not represent the true lateral variability of the reservoir; therefore, it is essential to capture the variations in lithology and porosity at the PEM calibration stage. Finally, the effect of vertical upscaling on seismic response has been illustrated. It is shown that the seismic response at larger vertical scales deviates more from the seismic response derived from the log-scale. I showed that the proposed solution in the literature for this issue, known as the scale-dependent PEM, is not fit for application to the simulation model and sim2seis. The analysis in this chapter shown that it is very challenging to preserve both the geological information and seismic responses at the larger scales. It is recommended here to perform the analysis at geological model scale and avoid working with large-scale simulation models, or perform sensitivity analyses to determine the appropriate scale that can preserve the seismic response. However, if the simulation model results are available at large-scale, performing sim2seis at geological model scale requires downscaling of the dynamic results to the fine-scale cells of the geological model. Downscaling is not straightforward and is a non-unique process. Although it is shown here that upscaling does not preserve the seismic response at the baseline and monitor surveys, a question that is not addressed in this thesis concerns the effect of the upscaling on the 4D response, an area of research that can be further investigated in future studies.
CHAPTER 4

Seismic Modelling for Sim2seis


4.1 Introduction

In 4D seismic studies, seismic modelling is used for three main purposes: 4D feasibility studies, 4D seismic acquisition design, and interpreting the 4D seismic data (Johnston, 2013). The 1D time-lapse feasibility studies are typically performed at well locations, using fluid substitution and seismic modelling to calculate the expected 4D (or 4D AVO) response. The 2D/3D time-lapse feasibility studies are performed to calculate the expected 4D response at different stages of production, as predicted by a fluid-flow simulation model. In the 4D seismic acquisition design and repeatability studies, seismic modelling is used to model the effect of seismic acquisition footprints and the seismic illumination on the 4D signal (Jones et al., 2002; Drotning et al., 2009). As mentioned in Chapter 1, seismic modelling is a part of sim2seis analysis for model-based 4D seismic interpretation and seismic history matching (SHM) workflows. Seismic modelling in sim2seis focuses on generating the seismic response at the reservoir interval, where the seismic response is governed by the geometry and distribution of the reservoir (static and dynamic) properties. Repeated computation of the seismic response of the simulation model in SHM workflows requires sim2seis to be executed many times. Therefore, a quick, yet robust, seismic modelling approach is favoured. In this chapter, the fastest seismic modelling approach “1D convolution” is compared with “pre-stack elastic finite difference (FD) seismic modelling”. As a direct seismic modelling method, FD modelling captures most of the features that influence the amplitude, including the source and receiver directivity and the wave propagation effects, such as spreading, reflection and transmission in discontinuities, scattering, focusing and defocusing; it therefore generates the closest response to wave propagation through the subsurface. The final stacked seismic section from the pre-stack modelling exercise also inherits the processing and imaging artefacts, and therefore the FD modelling creates the closest realization to the observed seismic data. This comparison allows evaluation of the accuracy of 1D convolution and the considerations needed to ensure that the accuracy is not compromised in favour of the modelling speed.
4.1.1 A review of 4D seismic modelling approaches

Seismic forward modelling is one of the most well-established areas in exploration and reservoir geophysics, with a wide range of applications including seismic acquisition design, seismic processing workflows, seismic interpretation, and also special seismic studies such as seismic inversion and lithology-fluid discrimination. A general review of seismic forward modelling is beyond the scope of this thesis; however Carcione et al. (2002) recognise three categories of seismic modelling techniques: direct methods, integral-equation methods, and ray-tracing (asymptotic) methods. Applicability of these methods depends on the type of earth models (1D, 2D, or 3D), the capability of modelling the different wave propagation features (multiples, converted waves, diffractions, etc.), their implementation, and the computational speed.

The most widely used method for seismic modelling is 1D convolution; however, some seismic modelling techniques, known as the hybrid methods, are also designed specifically for 4D studies on 2D/3D earth models. The idea behind the hybrid methods is to use a fast modelling approach in the coarse static overburden and a more sophisticated approach in the dynamic detailed reservoir interval. Lecomte (1996), Hokstad et al. (1998), Gjøystadal et al. (1998) propose a hybrid modelling scheme which combines local FD simulation in a complex reservoir zone with the ray-tracing techniques in a structurally simple overburden. In another approach called FD-injection, Robertson and Chapman (2000) and Robertson et al. (1996) followed a procedure very similar to that presented above, however they used finite difference in both overburden and the reservoir zone. Kirchner and Shapiro (2001) used a Born repeat-modelling technique, which is a combination of FD modelling and perturbation theory. Due to some obstacles to the practical implementation of hybrid methods, these were not widely recognised after being introduced in the literature. The main challenges include the different gridding in the overburden and the reservoir interval, and the coupling of the seismic response at the two sides of the interface between the overburden and the reservoir zone.

Hybrid methods are essentially developed to address the impact of the overburden footprint on the 4D signal. Such modelling tools are useful in
understanding the influence of a complex overburden on the 4D signature. Domes (2012) studied such effects in the Nelson Field (North Sea) where the imprint of channels in the overburden on the 4D signal is addressed. He also studied the production-induced amplitude changes of the upper reservoirs inside a deep-water stacked reservoir system in West of Africa. However, hybrid methods are not favourable in sim2seis analyses. What matters in sim2seis is the consistency of the simulation model and the seismic data at the reservoir interval. During seismic acquisition and processing/imaging stages it is intended to generate a clear, reliable seismic image at the reservoir interval; seismic processing algorithms are designed to remove any known overburden footprints that may mask the true seismic response at the target interval. Despite these efforts, it is likely that some of the undesirable effects are left untreated in the final processed seismic data. Nevertheless, during the seismic interpretation stage (e.g. in 3D seismic rock and fluid characterization or constraining the reservoir model to 3D seismic data), the seismic data at the reservoir interval are considered as the genuine reservoir response. Therefore, any attempt in introducing overburden complexity in the modelling of the reservoir response in sim2seis analysis will introduce a bias in the results, which will create a misleading interpretation of the synthetic seismic response at the reservoir interval.

4.1.2 Similar studies in the literature

A few studies have compared the different seismic modelling methods for 4D reservoir studies. The majority of the cases in the literature have addressed this issue qualitatively. Burnes et al. (2002) compared the 2D ray tracing method with a 2D hybrid method (ray tracing in the overburden and finite-difference in the reservoir interval) (Figure 4.1). The results are reported to be similar; both were successful in modelling the OWC response. Although not in a 4D study, Thore (2006) compared the 1D convolution and the finite-difference modelling and reported significant differences. Arts et al. (2007) compared the results of 1D convolution and the pre-stack finite-difference method (Figure 4.2). In this case, the modelling results were significantly different and the FD result had a better correlation to the observed 4D response. Marvillet et al. (2007) compared
the results of a 2D full waveform modelling with 1D convolution modelling (Figure 4.3). The modelling results were alike; however, the FD results showed a higher correlation to the observed data. Shahin et al. (2011) compared the semi-analytical split-step Fourier plane-wave technique with FD modelling, and investigated the effects of internal multiples and converted waves in the 4D response (Figure 4.4). These effects are found to be negligible compared to the 4D signature.

Based on the comparisons above, the key observations include the similarity of the main seismic features between the two methods and the lack of lateral discontinuity in the results of the 1D convolution. The differences between the two methods are attributed to different reasons, including seismic imaging, processing effects, the numerical dispersion effects in FD modelling, and the planar wave assumption versus cylindrical wave propagation in 1D convolution and FD respectively. In this chapter, a quantitative comparison between 1D convolution and FD seismic modelling is presented. It is showed that the1D convolution method generates very similar results to that of FD modelling, when the range of incident angles and an acquisition-controlled smoothing operator is included. Some issues are specifically associated with seismic modelling for sim2seis applications: e.g. the artefacts of vertically coarse sampled reservoir grids on the seismic response which were explained in the previous chapter. The complications associated with generating the seismic response from irregular reservoir grids and the alignment of the synthetic seismic response to the observed seismic data are discussed in this chapter. Seismic modelling of partial stacks and their implications in discriminating the effects of pressure and saturation changes are also covered here.
Figure 4.1 Seismic modelling in the Gullfaks Field in the North Sea; (a) modelled seismic response from a hybrid method (ray tracing in the overburden and finite-difference in the reservoir interval), and (b) modelled seismic response from ray tracing. Due to the lack of the diffracted waves and a poorer image of the complex geometry close to the fault, the ray tracing result seems to contain migration smiles and fewer details when compared to the hybrid method. However, with respect to modelling of the OWC response, the results from both methods are satisfactory (Burns et al., 2002).

Figure 4.2 Seismic modelling in the Sleipner CO₂ injection site; (a) observed 4D response, (b) synthetic 4D response from 1D convolution, and (c) synthetic 4D response from FD modelling. The difference between FD modelling and 1D convolution is significant. The FD result has a better tie with the observed data (Arts et al., 2007).
Figure 4.3 3D seismic modelling in the Bu-Hasa field offshore Abu-Dhabi; (a) observed seismic at baseline, (b) synthetic seismic from 1D convolution, and (c) synthetic seismic from full waveform modelling. Average correlation between the synthetic and the observed data in the reservoir section for the full waveform modelling and the 1D convolution methods is 55% and 45% respectively (Marvillet et al., 2007).

Figure 4.4 Seismic modelling in a 2D model (poorly consolidated shaly sandstone reservoir representing a prograding near-shore zone); (a) 4D response to 10 years of water-flooding from split-step Fourier plane-wave (SFPW) modelling without internal multiples, and (b) with internal multiples; (c) difference between (a) and (b) shows that the effect of internal multiples are negligible; (d) 4D response from FD modelling. The main differences are in the arrival times and the numerical dispersion in the FD data. The arrival times of the SFPW data are slightly less accurate than for FD because of the 1D with small lateral slowness variation assumption. The dispersion in the FD negatively affects most events and seems to be the most serious problem for matching the two data sets (Shahin et al., 2011).
4.2 Reservoir model description and PEM results

Here, a 2D section through a simulation model from the Schiehallion Field in the North Sea is chosen to perform the seismic modelling study. Figure 4.5 shows the location of the 2.5 km 2D intersection. As well as pressure and saturation changes, the 2D section contains some structural complexities such as faults and thin intra-shale layers. Figure 4.6 shows the distribution of porosity, volume of shale, saturation and pressure changes after six years of production. Reservoir thickness varies between 30 and 100 metres. The changes in the elastic parameters from PEM analysis are shown in Figure 4.7. The reservoir is embedded in a homogeneous shale background for seismic modelling.

![Figure 4.5 Seismic attribute map showing the reservoir quality in the Schiehallion Field. The channels are visible as warm colours. The location of the selected 2D intersection AB for seismic modelling is shown on the map.](image_url)
Figure 4.6 Static and dynamic properties in the 2D section AB from the Schiehallion simulation model. (a) porosity, (b) volume of shale, (c) saturation changes after 6 years of production, (d) pore pressure changes after six years of production.
Figure 4.7 PEM predictions. Changes in elastic properties after 6 years of production; (a) change in P-impedance, (b) change in S-impedance, (c) change in $V_P/V_S$ ratio.

### 4.3 Pre-stack 2D finite-difference (FD) elastic seismic modelling

Although it is not computationally cost effective, to avoid the complications of the hybrid methods as described earlier in Section 4.1.1, the same FD grid is applied to the whole earth model (the overburden and the reservoir). The following sections detail the settings for the FD modelling, the seismic survey, the seismic processing workflow and the final results.
4.3.1 FD modelling parameterisation

For this part of modelling, I wrote the seismic modelling programme in Fortran90, based on the popular staggered-grid FD scheme (Virieux, 1986; Levander, 1988) to solve the elastodynamic (velocity-stress) wave equation (2nd order in time and 4th order in space). The detail of this algorithm is explained in Appendix A. To increase the accuracy and the computational efficiency of the FD modelling, Holberg’s (1987) differentiators are implemented in the calculations. To minimise the effect of the spurious reflections from the computational boundaries of the model, the perfectly matched layer (PML) method (Berenger, 1994) is implemented at four sides of the model, with a layer thickness of 40 grid blocks. A P-wave point source is initiated by adding the source wavelet to the coupled diagonal stress components for each time step at the source locations. A 30 Hz Ricker wavelet is used for the modelling. To avoid the numerical artefacts in FD calculations, the spatial grid size and the temporal time step should be chosen based on the grid dispersion criterion and the stability limit of the staggered grid scheme (Virieux, 1986). In this exercise, according to these criteria, the spacing in the x and z direction is set equal to 0.9 m and the time step interval to 0.18 ms. One of the inherent features of FD modelling is that the derivative operator alters the source signature. Figure 4.8 shows the signature of the wavelet as initiated at the source location compared to the signature of the propagating wavelet.

4.3.2 Corner-point grid (CPG) to Cartesian grid conversion

The FD algorithm in this study requires an earth model with the regular Cartesian cells. However, the fluid-flow simulation model is built using irregular corner-point geometry (CPG), and therefore the CPG grid should be converted into the Cartesian grid. The average size of the cells in the CPG grid is 60 m (lateral) × 3 m (vertical), and in the Cartesian grid is 0.9×0.9 m. An algorithm is designed for extracting pseudo-logs from the CPG grid, the details of which are covered in Section 4.6. This algorithm is also adapted to perform the grid conversion. The result of the grid conversion is shown in Figure 4.9. A favourable resemblance between the two grids ensures that the information is preserved during the grid transformation.
Figure 4.8 The wavelet used in FD modelling. The red wavelet is a 30 Hz Ricker wavelet that is injected at the source location in the FD calculation. The blue wavelet is the propagating wavelet through the media.

Figure 4.9 Corner-point grid (CPG) to Cartesian grid conversion (a) the vertical intersection through the reservoir model in corner-point geometry (60m×3m), and (b) the intersection after conversion to the Cartesian grid (0.9m×0.9m).
Figure 4.10 The computational grid (2970×6480 m, 3100×7200 grid) shows the reservoir section and the horizontal interface above. The geometry of the sources and streamer is shown at the top. The maximum fold is 28 and the reservoir falls within the full-fold area. The brown box shows the active numerical grid for one of the shot points and the associated receivers.

4.3.3 2D seismic survey

A 2D marine survey is designed for FD modelling. Table 4-1 summarises the survey parameters. To account for the acquisition and migration aperture, the model is extended on both sides such that full fold is acquired over the reservoir zone. The extended model has a grid size of 3100×7200. To decrease the runtime, only that part of the model that is required for each shot point (a grid size of 3100×4100) is included in FD calculations. Figure 4.10 shows the extended numerical model, the geometry of the sources and streamer, the fold distribution and the numerically active part of the model for an arbitrary shot point. A seismic streamer with length of 2.5 km with 112 hydrophones with spacing of 22.5 m records the response for three seconds. The minimum and maximum source-receiver offsets are 45 m and 1250 m respectively. This gives 83 shot points with a spacing of 45 m, located 5 m below the streamer. Note that all the spacing distances are multipliers of the cell size of 0.9 m. The modelled shot gathers are free of surface waves and any random noise (Figure 4.11).
Table 4-1 The parameters of the 2D marine seismic survey in FD modelling.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>number of shot points</td>
<td>83</td>
</tr>
<tr>
<td>shot spacing</td>
<td>45 m</td>
</tr>
<tr>
<td>streamer length</td>
<td>2520 m</td>
</tr>
<tr>
<td>number of hydrophones</td>
<td>112</td>
</tr>
<tr>
<td>receiver spacing</td>
<td>22.5 m</td>
</tr>
<tr>
<td>minimum offset</td>
<td>45 m</td>
</tr>
<tr>
<td>common-mid point (CMP) spacing</td>
<td>11.25 m</td>
</tr>
<tr>
<td>maximum fold</td>
<td>28</td>
</tr>
<tr>
<td>dominant frequency</td>
<td>30 Hz</td>
</tr>
</tbody>
</table>

Figure 4.11 A shot gather from FD calculations with automated gain control (AGC) filter to highlight the deeper events. The different events are marked as: 1) the direct wave, 2) the spurious boundary reflections from two sides of the computational grid, 3) the P-wave reflection from the horizontal interface above the reservoir, 4) the P-wave reflection from the reservoir, 5) the diffractions from sharp edges and discontinuities in the reservoir, 6) the spurious boundary reflection from the base of the computational grid. It should be noted that the real relative amplitude of spurious reflections from the boundaries is small compared to the other events.
4.3.4 Seismic processing workflow

Once all the 83 shot gathers are created, ProMax2D™ software is used for seismic processing and migration. The same modelling procedure and processing workflow is applied to the baseline and monitor surveys. Figure 4.12 shows the processing workflow that includes the following steps:

Data input – The SEGY file containing 83 shot gathers is imported into ProMax2D. Each shot gather contains 112 traces of 1500 time samples each, with a sampling interval of 2 ms.

Geometry loading – The survey geometry is generated in ProMax2D. It contains the indexes and coordinates of the sources and receivers.

True amplitude recovery – To account for amplitude loss due to geometrical spreading, the function $1/(time.Velocity^2)$ is applied to recover the true amplitude.

Trace binning – The offset gathers are sorted for the migration algorithm.
Migration – The pre-stack Kirchhoff time migration algorithm is applied for imaging. Two different scenarios for the choice of migration velocity between the baseline and monitor surveys are examined. In the first scenario, the RMS velocity for the baseline survey is applied to the both baseline and monitor surveys, and in the second scenario the RMS velocities for the baseline survey and monitor surveys are used separately for migration. The velocity difference between baseline and monitor survey is shown in Figure 4.13. The results of modelling are shown in Figure 4.14. These results demonstrate that, in this exercise with a very simple overburden and a thin reservoir, the production related changes in RMS velocity are not big enough to impose a dramatic change on the final 4D signal (Figure 4.14 (e)). It should be noted that although the 4D difference in the interval velocity is up to 70 m/s, the difference in the RMS velocities is very small (less than 2 m/s). In a case study in West Africa, Chen et al. (2014) observed that increases in gas saturation lead to significant velocity changes in the shallow reservoir between surveys. As a consequence of these significant velocity changes, large time shifts are induced between the seismic reflection events of the baseline survey and those of the monitor survey, causing imaging repeatability problems and uncertainties in the 4D seismic interpretation for the underlying reservoirs. Migrating the baseline and monitor data with the same velocity model was found to be inadequate. In this case, production induced changes in velocity are incorporated into the migration of the monitor survey.

\[ \Delta V_{\text{int}} \text{ (m/s)} \]

\[ \Delta V_{\text{RMS}} \text{ (m/s)} \]

Figure 4.13 (a) The change in the interval velocity between baseline and monitor surveys, and (b) the change in the RMS velocities between baseline and monitor surveys.
**Ensemble stacking** – The migrated offset gathers are stacked after migration to generate the final stacked section.

**Data output** – The final stacked section is exported as a 2D SEGY file.

### 4.4 1D convolutional modelling

Following the application of finite-difference (FD) seismic modelling, 1D convolution, which is the most widely used method for seismic modelling, is applied to the same earth model. The 1D convolution algorithm is explained in Appendix A. Figure 4.15 shows the key components of the 1D convolution model for generating a post-stack seismic section. In this method, the vertical (1D) pseudo-logs at each common mid-point (CMP) location at each seismic bin are extracted. To simulate the full stack seismic response, considering the corresponding range of angles of incidence (assuming a horizontal reflector), the Zoeppritz equations (Aki and Richards, 2008) are used to calculate the elastic reflectivity coefficients at each CMP. Although it is not shown here, including the local dip in calculations does not have a significant effect. One can include wavelet stretching effects in creating the CMP gathers for more realistic modelling. The average of the reflectivity series for all CMPs in each bin is calculated and assigned to the centre of each bin. The range of angles of incidence can be modified to generate partial stacks. The mean reflectivity series in depth is converted to two-way-time (TWT) using the velocity from the PEM. The reflectivity series in time is discretised by careful selection of the sampling interval to ensure it is small enough to preserve the reflectivities at all the interfaces. The wavelet is also discretised using the same sampling interval and is convolved with the discretised reflectivity series to generate the synthetic trace. The resulting trace is assigned to the centre of the bin. This procedure is applied to all the seismic bins. In case the CMP locations in each bin are not known, a pseudo-log is extracted at the centre of the bin and a range of angles is used in Zoeppritz’s equation to calculate the mean reflectivity series and the full stack seismic response.
Figure 4.14 FD modelling results, (a) baseline seismic response, (b) monitor seismic response, (c) the 4D seismic response (monitor-base). To highlight the differences, the amplitude in the difference sections is multiplied by two, (d) the 4D seismic response at the reservoir interval, (e) the influence of (PSTM) migration velocity on the 4D response is negligible. In one case, the monitor survey is migrated by the baseline RMS velocity and in the other case by using the monitor RMS velocity. This section shows the difference between the two cases; (f) baseline trace at CMP 240. The seismic signature of the isolated interface above the reservoir is chosen as the wavelet for 1D Convolution.
Figure 4.15 The key components of the 1D convolution algorithm. The geometry of the seismic grid and the position of the CMPs are extracted from the seismic geometry.

4.4.1 Wavelet

In practice, the wavelet for sim2seis modelling is either extracted statistically from the observed baseline seismic cube, or is extracted deterministically by performing a well-tie. It is important to point out that the wavelet should be consistent over the lateral extent of the reservoir. The importance of the wavelet in sim2seis modelling is highlighted in Chapter 6, where it is shown how the choice of wavelet can change the sign of the 4D signal. In this study, the wavelet is extracted from the single isolated reflector (see Figure 4.14(f)) above the reservoir in the FD result and used for convolution. Different wavelets can be used for near and far angles in modelling the CMP gathers, to take to account the different frequency content in the partial stacks.

4.4.2 Imaging calibration (Migration operator)

Figure 4.16 shows the seismic section from 1D convolution versus the FD section for the baseline survey. The main difference between the two sections is that the FD result is laterally smooth and more continuous, whereas the 1D convolution section shows all the lateral details; for example, the boundaries of the simulation model cells are visible in the seismic section. This is due to the
fact that the 1D convolution algorithm in Figure 4.15 considers the reflections as being from a point, while in reality the reflected information comes from an area also known as the Fresnel zone. To take to account the Fresnel zone and the lateral seismic resolution, the migration operator (a.k.a. the resolution function) should be convolved with the seismic section from 1D convolution. Figure 4.17 shows the algorithm for creating a migrated post-stack seismic section based on 1D convolution.

Figure 4.16 FD modelling versus 1D convolution; (a) the baseline seismic section from FD modelling, (b) the baseline seismic section from 1D convolution. As highlighted in the circle, the discontinuities at the cell boundaries of the simulation model are visible in the seismic section from the 1D convolution modelling.
**Figure 4.17** The adapted 1D convolution algorithm to simulate a migrated post-stack seismic section. The seismic section from the conventional 1D convolution is convolved with the resolution function (adapted from Toxopeus et al., 2003).

**The seismic spatial resolution operator**

The seismic spatial resolution operator is the seismic image of a single scatter point, which depends on the depth, the background velocity, the seismic survey geometry, the wavelet frequency spectrum, and the migration type (post- or pre-stack). Different approaches exist to calculate this operator. Toxopeus et al. (2008), list three different approaches as: (1) closed-form expression (Chen and Shuster, 1999), (2) angle and band-limitation filter (Lecomte and Gelius, 1998; Xie et al., 2006), and (3) combined operator. In this study, I used the first approach (Chen and Shuster, 1999, see Appendix C) and extended it from single frequency calculations to the band-limited wavelet. Figure 4.18 shows the resolution function for three selected single frequencies (10 Hz, 30 Hz, 90 Hz) and for the full bandwidth for a scattering point lying at the reservoir depth. Ideally, the resolution filter should be calculated for each scatter point in the target zone. However, because the overburden in this case is very simple and the reservoir is thin, the resolution filter does not significantly vary laterally across the reservoir zone. The shape of the resolution function also depends on the survey coverage.
Figure 4.18 The resolution functions at different CMP locations and frequencies; (a) the resolution function at 5 Hz, (b) the resolution function at 30 Hz, (c) the resolution function at 90 Hz, (d) the full bandwidth resolution function, and (e) the comparison between the resolution functions at different frequencies at CMP location 220.
Figure 4.19 The variations of the resolution function at different CMP locations. The resolution function at the edges with lower fold coverage is different from the resolution function at the full fold area at the centre.

Figure 4.20 The conventional 1D convolution versus the adapted 1D convolution. (a) the seismic section before application of the resolution function, and (b) the seismic section after application of the resolution function.
Figure 4.19 shows the variations of the resolution function at different CMP locations. In this exercise, the resolution function from the full fold area (CMP 220 in Figure 4.19(b)) is chosen and convolved with the seismic section from the 1D convolution. Figure 4.20 shows the 1D convolution section after application of the resolution function. Alternatively, the filter can also be applied to the earth model prior to 1D convolution.

One of the important aspects of simulator to seismic modelling is the lateral scale differences between the seismic data and the geological/simulation model. It should be noted that what is commonly referred to as the seismic bin size is not the true representative of the spatial resolution of the seismic data. For example, in this exercise the bin size is 11.45 m, while the size of the Fresnel zone after migration is around 60 m. Figure 1.10 depicts the different lateral scales in sim2seis modelling and the difference between the seismic grid and the lateral seismic resolution.

4.5 FD modelling versus 1D convolution

In this section, the modelling results are summarised and the difference between the 1D convolution and the FD modelling are discussed in more detail. In terms of computational cost, the computation time for 1D convolution modelling in this example is in order of minutes, whereas the total FD modelling computational time is more than 13 days per survey and the seismic processing and migration takes an hour per survey. It is worth mentioning, however, that these timings only cover the pure computational time, and that the time needed for the data preparation should also be considered in a more realistic evaluation of the cost of the computations. In this exercise, by distributing the FD modelling task over 16 computational nodes in a cluster, the runtime is decreased to 9 hours.

4.5.1 FD modelling versus 1D convolution (Baseline survey comparison)

The results of seismic modelling from both methods are summarised in Figure 4.21. To perform a more detailed comparison, the baseline seismic response from 1D convolution is subtracted from the seismic response from the FD method.
The average amplitude difference between the two methods is small (less than 10%); however, to highlight the dissimilarities, the amplitudes in the difference sections are multiplied by two. The major differences belong to the structural discontinuities, e.g. at the edges of the model, fault locations, and the boundaries of the grids in the simulation model. Figure 4.21 shows the average difference between the two methods in a time window of 1300-1500 ms. After application of the migration operator (resolution function) (Figure 4.21 (c)), the main differences disappear and the average difference is decreased to a lower level.

4.5.2 FD modelling versus 1D convolution (4D comparison)

The 4D sections from both methods are shown in Figure 4.22. Similarly to the baseline comparison, the results from 1D convolution after application of the migration operator and FD modelling are visually very similar. To perform a more quantitative comparison, the horizons at the top and base of the reservoir are picked and the RMS amplitude between these horizons is calculated for the baseline and the monitor surveys. Figure 4.23 shows the difference between the RMS amplitudes at the baseline and the monitor surveys for both modelling methods. Although the 4D RMS curves follow the same trends, they do not precisely coincide and an average difference of 15% is observed in the 4D RMS between the two methods.
Figure 4.21 Seismic modelling comparison between finite difference (FD) and 1D convolution for the baseline survey; (a) the section from FD, (b) the section from conventional 1D convolution, (c) the section from adapted 1D convolution after application of the resolution function; it is visually very similar to the section from FD modelling; (d) the difference between (a) and (b), (e) the difference between (a) and (c). To highlight the differences, the amplitude in the difference sections is multiplied by two; (f) the average of amplitudes between top and base for the sections in (a), (d), (e) in black, red and blue respectively.
Figure 4.22 Seismic modelling comparison between finite difference (FD) and 1D convolution for the 4D sections (monitor-baseline). (a) the section from FD, (b) the section from conventional 1D convolution, (c) the section from adapted 1D convolution after application of the resolution function is visually very similar to the section from FD modelling; (d) the difference between (a) and (b), (e) the difference between (a) and (c). To highlight the differences, the amplitude in the difference sections is multiplied by two.
Figure 4.23 The 4D RMS attribute (RMS(monitor)-RMS(baseline)) from FD and 1D convolution between top and base horizons (horizons are shown in Figure 4.21a). The difference between the two methods for small values of RMS can be noteworthy (e.g. around CMP 220). At this location, pressure build-up at the base of the reservoir and water-flood responses at top of the reservoir cancel each other out. In such circumstances, the error in discrimination of pressure and saturation changes between the two methods becomes significant.

4.6 Pseudo-log extraction from corner-point geometry grids

Generally, the geometry of the grids in the geological models and simulation models is built to be consistent with the geological features, flow units, and fault planes. Therefore, the grids are often built using non-vertical pillars and irregular cells (corner-point geometry (CPG)). To perform the 1D convolution on the CPG grids (or any form of irregular grid), the vertical pseudo-logs should be extracted at each CMP location. The programme that is developed here extracts the pseudo-logs based on the grid geometry of the Eclipse simulation model. The pseudo-logs contain the interfaces of the simulation model grids and the elastic properties between each interface. In extracting the interfaces, one should not rely on cell indexes in the $k$ direction and care must be taken where oblique pillars or pinch-outs can form complicated situations (Figure 4.24).

4.7 Horizon alignment for synthetic seismic

In sim2seis applications, the elastic properties for overburden and underburden are chosen to ensure the correct reflectivity is modelled at the top and base of the reservoir. Generally, the immediate overburden/underburden properties from well log data are assigned to the overburden/underburden. Nevertheless, this choice of velocity for the overburden does not guarantee the same two-way-time (TWT) for the synthetic traces as for the observed traces. This is due to the fact that the velocity that is used for performing the time to depth
Figure 4.24 The 3D (left) and 2D (right) illustration of the complications of 1D vertical pseudo log extraction in the models with corner-point geometry and non-vertical pillars. In the example in the right, the number of interfaces (=6) are more than the number of horizons in the simulation model (=4). Extracting the pseudo-logs along the pillars (i.e. the cell k-index direction) is not the true representation of variations in the vertical direction.

Conversion in the reservoir model building is generally laterally heterogeneous and is different from the velocity that is assigned to the overburden for sim2seis modelling. Therefore the synthetic seismic data will be mispositioned in TWT and will not be directly comparable to the observed seismic data (Figure 4.25(a) and (b)). This is an issue particularly where the interpreted TWT horizons based on the observed seismic data are used to generate the synthetic attribute maps.

The reservoir models are often built using one (or more) interpreted TWT horizon that is converted to depth. Here the horizon pair in TWT and depth are used to align the synthetic seismic to the observed data. In this method (Figure 4.25), the velocity from the PEM is used to convert the depth horizons in the reservoir model to TWT. In the next step, the observed interpreted TWT horizon is compared to its corresponding TWT horizon from the reservoir model and the difference between the TWTs is applied to each of the synthetic traces as a static shift. From another perspective, this procedure can be considered as modifying the overburden velocity at each trace location to match the synthetic TWT to the TWT of the observed seismic data (Figure 4.26). The method that
Figure 4.25 Aligning the synthetic seismic to the observed seismic; (a) observed seismic, (b) synthetic seismic before alignment; note that the TWT of the events is different from the observed seismic; (c) the corresponding depth horizon Top 31A is marked in the reservoir model; (d) synthetic seismic after alignment. The locations where this method is not able to perform the alignment successfully are marked. In these locations, the interference from upper sand geobodies distorts the phase of the waveform.
Figure 4.26 The overburden velocity ($V_p$-OB) used to align the synthetic seismic to the observed seismic (see Figure 4.25). For sim2seis modelling, the velocity used for overburden is 2811 m/s to ensure the correct reflectivity at top of the reservoir. This velocity is different from the velocity required to place the synthetic seismic in the right location.

is described here aligns the TWT of a seismic event (peak, trough, or zero-crossing) to the TWT of the corresponding reflection coefficient in the reflectivity series of the synthetic seismic. In locations where the phase of the waveform is distorted due to upper and lower interferences, this method cannot perform the alignment successfully (Figure 4.25(c)).

4.8 Partial stacks and pressure and saturation discrimination

4D inversion concerns extracting pressure and saturation changes from 4D seismic. Different methods are developed in the literature to use partial stacks in discriminating the signatures of the pressure and fluid-phase changes (Landrø, 2001; Ribeiro and MacBeth, 2004). The value of sim2seis in the calibration of 4D inversion is denoted here. Partial stacks are generated for the Schiehallion Field in the North Sea (Figure 4.27). The 4D maps for near (0°-10°), and far stacks (20°-30°) are compared with the individual 4D seismic signature of pressure and saturation variations. Here, the same wavelet is used for creation of the partial stacks. PEM is modified to obtain the independent 4D response of pressure and saturation changes (Figure 4.28). By comparing the partial stacks with pressure-only and saturation-only maps, it is observed that the 4D map for the near angle stack (Figure 4.27(a)) carries the information from both saturation and pressure responses; whereas the 4D map for the far
angle stack (Figure 4.27(b)) is saturation dominated and is similar to the saturation-only map (Figure 4.28(a)). The difference between near and far 4D maps (Figure 4.27(c)) is very similar to that of the pressure-only response. Specifically, around the wells with higher pressure changes (I6, P2, and P4), the resemblance between the two maps is higher.

4.9 Summary

This chapter has presented a review of the seismic modelling applications in 4D reservoir studies. By referring to the philosophy of seismic modelling in sim2seis, it has been explained why the so-called hybrid seismic modelling methods are not fit for general sim2seis applications. As seismic modelling is the most time-consuming element of sim2seis, the speed of sim2seis calculations in SHM applications is a concern. In a detailed seismic modelling exercise, 1D convolution as the fastest seismic modelling method is compared with pre-stack elastic finite difference seismic modelling. This comparison allows recognition of the key elements of the seismic modelling to ensure that an accurate seismic response is calculated. Following the application of the PEM to the Schiehallion reservoir model, a 2D section containing structural complexities and variations in pressure and saturation changes is chosen to perform seismic modelling. A 2D marine survey was designed for pre-stack seismic modelling. The corner-point simulation model grid is converted to a Cartesian grid for FD modelling. The staggered-grid FD scheme (Virieux, 1986; Levander, 1988) is used to solve the elastodynamic (velocity-stress) wave equation (2nd order in time and 4th order in space). The generated pre-stack data is then processed and migrated to generate the final stacked seismic section. For 1D convolution, the wavelet is extracted from the seismic section from FD calculations. The distribution of CMPs and their associated angle of incidence is also included in 1D convolution.
Figure 4.27 4D maps (SNA(monitor)-SNA(baseline)) for partial stacks (SNA: sum of negative amplitudes): (a) 4D map for near angle stacks (0°-10°); this map shows the effect of both saturation and pressure changes (see Figure 4.28); (b) 4D map for far angle stacks (20°-30°); this map is more saturation dominated (Figure 4.28(b)); (c) the difference between near and far 4D maps is dominated by pressure changes.
Figure 4.28 4D seismic signature (SNA(monitor)-SNA(baseline)) of pressure and saturation variations (SNA = sum of negative amplitudes). PEM is modified to obtain the 4D response of pressure and saturation variations independently; (a) saturation-only 4D map, where the rock stress-sensitivity is ignored but it takes to account the changes in fluid saturations and the pore pressure sensitivity of the fluid properties; (b) pressure-only 4D map depicts only the response of dry-rock to pore pressure changes.

Taking these considerations into account, the 1D convolution results have similar amplitude variations; however, unlike the FD seismic section, the discontinuities of the simulation model grid are reflected in the 1D convolution seismic section. 1D convolution without application of the migration operator (resolution function) suffers from sharp discontinuities. After application of the resolution function to the 1D convolution, the visual resemblance between the 1D convolution and FD results is remarkable. In a quantitative comparison between the two methods, it is observed that the average difference between average amplitude between top and base of the reservoir is 10%, and the
average difference in 4D RMS amplitude is 15%. In computational cost terms, 1D convolution modelling computation time is in the order of minutes, whereas the total FD modelling computational time is more than 13 days per survey and the seismic processing and migration takes an hour per survey. Following these results and considering the calculation time of the two methods, the adapted 1D convolution generates a satisfactory result and is recommended to be used in sim2seis applications. In this study, the full stack seismic sections are compared. This comparison can be performed for the pre-stack data and the AVO (amplitude versus offset) response of the two methods evaluated. Some recommendations for improvement of 1D convolution results are presented in Chapter 7.

The complications of extracting pseudo-logs from corner-point geometry simulation grids have also been addressed in this chapter. To reflect a true representation of the simulation model in the seismic response these details should not be ignored. A method has also been presented to align the sim2seis results with the observed seismic data. This allows a one-to-one comparison with the observed seismic response. In the last part of this chapter, sim2seis was used to generate the 4D response of partial stacks. These responses were compared with the 4D seismic signature of pressure and saturation variations. It was shown that 4D seismic for far angle stacks was saturation dominated, and the difference between near angle stacks and far angle stacks was pressure dominated. This exercise can be used to calibrate the 4D inversion algorithms based on partial stacks.
CHAPTER 5

Sim2seis Application to the Schiehallion Field
**Figure 5.1** The Schiehallion Field is a part of the West of Shetland Basin close to the Foinaven and Loyal Fields.

### 5.1 Schiehallion Field

The Schiehallion Field (Figure 5.1) is a part of the West of Shetland Basin that was discovered in 1993 and started production in 1998. The Schiehallion Field comprises multiple stacked Tertiary turbidite sandstone reservoirs with porosity 25-30% and permeability 200–1000 mD. Each reservoir is composed of channels, amalgamated channels and unconfined sheet-like sands. The field is heavily compartmentalised, with faults cross-cutting turbidite sand depositional axes. Schiehallion contains black oil accumulations close to bubble point and small local gas caps. The field has been developed under waterflood, using down-dip injectors and up-dip producers (Martin and Macdonald, 2010). Based on the PEM calculations in Chapter 2, an up to 5% increase in acoustic impedance due

![Diagram of Schiehallion Field](image)

**Figure 5.2** Timing of the 4D seismic surveys over the Schiehallion Field. The available surveys for the study in this thesis include the baseline in 1996 (BL), and three monitors in 2004, 2006, and 2008 (M4, M5, M6).
to water-flooding and up to 9% decrease in acoustic impedance due to gas break-out are expected in this reservoir. 4D seismic is recognised as the key reservoir surveillance tool to address well planning and well interventions.

Figure 5.2 shows the seismic survey timing over the Schiehallion Field. Over the years, with developments in dedicated 4D seismic processing workflows, different sets of vintages have been reprocessed to achieve a more reliable 4D signature by enhancing the imaging and reducing the non-repeatable noise. In this thesis, the latest 4D processed dataset that was available at the time is used; this includes the 2008 processing of the four seismic vintages (baseline 1996, and three monitor surveys 2004, 2006, and 2008). Figure 5.3 shows the enhanced seismic image due to the improvement of the processing and imaging workflows.
Figure 5.3 Improvement in seismic imaging due to advancement in seismic processing workflows; (a) 1998 processing of the baseline data (quadrature trace), (b) 2008 reprocessing of the baseline data (quadrature trace).

The connectivity across the reservoir is the primary factor in understanding well performance and reservoir sweep in the Schiehallion Field. Therefore, a geological modelling approach is developed which enables adjusting the connectivity between different geobodies. Geobodies are considered as a “small scale, seismically mapped discrete subdivision of the reservoir that reflects dynamic data based on 4D seismic and/or production/injection data” (Martin and Macdonald, 2010). Figure 5.4 shows a vertical seismic section and the corresponding reservoir model. Seismic NTG (Connolly, 2007) is used to populate the NTG in the reservoir. The algorithm detunes the average amplitude response of a 100% net-to-gross wedge using a correction function modelled from the wavelet specification, to estimate the seismic net to gross. Figure 5.5 shows the lateral distribution of geobodies and NTG in the reservoir model. From a reservoir simulation point of view, each geobody is a group of contiguous cells in the model, characterised as being in the same transmissibility region. The keyword TRSD in the Eclipse model is used to adjust the transmissibility multipliers between the neighbouring geobodies. Figure 5.6 shows an example of the transmissibility multipliers for the geobodies surrounding injector II. Here, the geological model is also used as the fluid flow simulation model. Figure 5.5 shows the 10 injectors and 10 producers operating in Segment 1 of the Schiehallion Field up to 2008. Timings of the well activities and seismic surveys are shown in Figure 5.7. The hierarchy of uncertainties in Seismic History Matching (SHM) workflow was covered in Chapter 1, and the weights of the production data versus the 4D seismic data in the misfit function in the SHM algorithm were discussed. It was also mentioned that these weights differ, based on the importance of the role of the production data and the 4D seismic in the reservoir management plan. As mentioned earlier, 4D seismic plays a key part in reservoir management in the Schiehallion Field. The available simulation model has a moderate match to fluid production/injection volumetric and is poorly matched to pressure data. However, the consistency of the reservoir model with the 4D seismic is essential in the development of the
field. Sim2seis can be used to check the consistency between the different simulation models and the consistency between the reservoir model and the 3D/4D seismic data.
Figure 5.4 Reservoir model building based on “geobody” extraction from seismic data; (a) quadrature seismic section; (b) geobodies from the reservoir model corresponding to sand geobodies from seismic section; different colours are used to distinguish separable geobodies. The transmissibility multiplier between geobodies is used to control connectivity across the reservoir; (c) Connolly’s (2007) method for seismic NTG calculation is used to populate net-to-gross (NTG) in the geobodies. Higher NTG geobodies correspond to brighter amplitudes in the seismic section.
**Figure 5.5** Segment 1 of the Schiehallion Field: (a) seismic attribute (sum of negative amplitude in T31A interval from quadrature) showing the channels in warm colours; (b) geobodies in the reservoir model corresponding to sand geobodies from seismic data; the transmissibility multiplier between geobodies is used to control connectivity across the reservoir; (c) net-to-gross (NTG) population in the geobodies, based on Connolly’s (2007) method.

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Transmissibility multipliers between geobody pairs in $\Gamma_{31A}$

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Transmissibility multipliers between geobody pairs in $\Gamma_{31B}$

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**Figure 5.6** Keyword TRSD in Eclipse is used to set the transmissibility multipliers between the neighbouring geobodies. Shown is a part of the Eclipse file for assigning the transmissibility multiplier between the geobody pairs around Well 11.
Figure 5.7 Timeline of activities of injectors (I1 to I10) and producers (P1 to P10) from 1998 to 2009. The times of the acquisition of the monitor seismic surveys are shown here. The last three monitor surveys (M4, M5 and M6) are used in this study (Obidegwu and MacBeth, 2014).
Figure 5.8 Observed 4D seismic data (SNA(monitor)-SNA(baseline)) SNA: sum of negative amplitudes in T31A interval from the quadrature section. SNA is chosen because the sand geobodies are characterised as a trough on the quadrature seismic section. The first level of 4D seismic interpretation is tying the observed 4D signatures with the well production data. The bubble plots show the cumulative injection/production fluid volumes. (a) 2004-1996, (b) 2006-1996, (c) 2008-1996.
In Chapter 1, the different consecutive levels of 4D interpretation (Figure 1.4, page 9) were outlined. It was mentioned that production data stands as the ground truth in 4D seismic data interpretation. Thus, the foremost essential step in 4D seismic data interpretation concerns tying the production data to the 4D signatures, in which the hardening and softening signals are matched to the well activities. It should be noted that the registration of the 4D signal in the reservoirs whose seismic signature consists of several cycles of peaks and troughs (e.g. the Girassol Field in offshore Angola) is a challenge. In the Schiehallion Field, the sand geobodies are below tuning thickness and are represented with one cycle only.

Figure 5.8 shows the 4D maps in segment 1 of the Schiehallion Field and the corresponding bubble plots that show the cumulative produced/injected fluid volumes. In these 4D maps, cold colours represent hardening, and warm colours represent softening. The hardening signal is largely due to water flooding and, knowing the history of the production in the Schiehallion Field, the majority of the softening signal is due to gas breakout.

Here, I review a few examples of managing the well intervention and planning using 4D seismic in Segment 1 of the Schiehallion Field. Production data shows that injector I1 fails to support the producer P2 in the south east of the field (Allan and MacDonald, 2011); this is also evident from the 4D seismic water flood signature around I1 (Figure 5.9), where water cannot sweep oil towards the south east of the field where P2 is located. Therefore, injector I1 is replaced with I6, which commenced injection less than 2 years prior to the monitor survey, in 2004, in the channel further north of I1. The boundaries of the geobody that contain well I6 are acting as sealing pressure boundaries which results in pressure build-up in this geobody (a map of pressure changes from the simulation model is shown in Figure 5.14). Unlike the rest of the softening signals in the map, that are due to gas breakout, the softening in this geobody is due to pressure build-up. The hardening signal around this injector is where the oil has been replaced by water. This geobody portrays a prime example of the competing effects of hardening due to water-flood and softening due to pressure
**Figure 5.9** (a) managing well intervention and planning, using 4D seismic. It is evident from 4D seismic that injector I1 fails to support the producer P2 in the south east of the field. The softening around producer P2 is due to gas breakout and accumulation. Therefore, injector I1 is replaced with I6 in the channel further north of I1. I6 started injection of less than 2 years prior to the 2004 monitor survey. (b) Water saturation and pressure build-up signal around well I6.

**Figure 5.10** Schematic illustration of the competition between saturation and pressure build-up signal in the geobody containing well I6. The transition zone between the fully swept zone and non-swept zone is visible on the 4D signal.
build-up around injectors. Interestingly, on a closer scrutiny of the 4D signal in this geobody (Figure 5.9b), 4D seismic depicts the transition between a pure pressure signal (at the edges) and where the saturation signal dominates (fully swept area around injector). The schematic illustration of the saturation versus pressure signal in this compartment is shown in Figure 5.10. From a reservoir management point of view, monitoring the saturation signal is crucial to distinguish the water-flooded areas, bypassed oil and fluid-flow migration routes and to assess the connectivity across the reservoir. The pressure signal can also be used to reveal the boundary compartments, reservoir connectivity and to flag over-pressured areas.

Another area where 4D seismic is used for well intervention and planning is in the centre and west of Segment 1 (Figure 5.11). Lack of support for P1 and P4 producers was evident from well data (Allan and MacDonald, 2011). The 2004-1996 4D map is used to identify the locations for additional producer and injector pairs (I9 and P8) that were brought online in 2006. An extra injector, I10, was also added in 2007. The 2008-1996 4D map (Figure 5.11c) shows the efficiency of the sweep as a result of these wells.

5.2 Sim2seis in Schiehallion

Depending on the frequency of the 4D surveys, the timing between the snapshots of the reservoir may not be sufficient to capture the short-lived reservoir processes (Table 5-1). Simulation models provide a more detailed understanding of the transitory mechanisms that drive the evolution of the reservoir between the 4D surveys. In particular, the Schiehallion Field being close to bubble point, the simulation model is of great help in the understanding of gas liberation/dissolution and its subsequent migration paths throughout the reservoir. For example in the area around producer P1 (Figure 5.12), gas comes out of solution immediately after the start of production. This is followed by gas accumulation and migration towards local highs around fault F1. The simulation model depicts how the repressurisation due to the introduction of injectors (I3, and I5) in the north of the field affects this process by forcing the liberated gas back into solution.
Figure 5.11 Managing well intervention and planning using the 4D seismic. (a, b) The 4D (2004-1996) map is used to identify the locations for additional producer and injector pairs (I9 and P8) that are brought online in 2006. (c) An extra injector I10 is also added in 2007. The 2008-1996 4D map shows the efficiency of the sweep as a result of these wells.
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<tr>
<td>High/low salinity flood</td>
<td>Months</td>
</tr>
<tr>
<td>Miscible/immiscible gas injection</td>
<td></td>
</tr>
<tr>
<td>Polymer injection</td>
<td></td>
</tr>
<tr>
<td>Thermal flood</td>
<td></td>
</tr>
</tbody>
</table>

Table 5-1 Different reservoir processes and timelines (Watts and Marsh, 2011).

In addition to the well activities, gas migration and distribution is a function of gravity effects, relative permeability and vertical and horizontal permeability. Figure 5.13 shows the changes in pressure at P1, P3 and P6 and the cumulative injected water I3, I5 from the simulation model. Based on these plots, injector I2 supports well P1 and injector I5 supports well P3. It is not clear which specific injectors are supporting producer P6.
Figure 5.12 4D interpretation based on the simulation model. Evolution of gas in the reservoir based on simulation model predictions; (a-c) between start of production and 2001, gas comes out of solution and migrates toward local highs near faults (F1, and F2). (d) In 2001, by introducing producer P6 and injector I4, part of the gas is produced and a part has gone back to solution; (e) by 2002, parts of the reservoir are depleted further, and gas dissolution continues (e.g. below fault F1 where injector I1 fails to support the pressure and gas comes out of solution). (f, g) Injector I6 in 2003 and injector I8 in 2004 are introduced to support the south of the field, where part of the gas is dissolved as a result. (h) Contrary to the simulation predictions in 2004 (g), the observed 4D seismic shows the presence of gas in the centre of the field.
Figure 5.13 (a) pressure variations at producers P1, P3 and P6 from simulation model; (b) cumulative water injection volume at injectors I2, I3, I4 and I5 from simulation model. Well P1 is supported by injector I2, well P3 is mainly supported by injector I5. It’s not clear which specific injectors are supporting producer P6.

Above is an example of model-based 4D seismic interpretation – the second level of 4D interpretations – where the comparison of 4D seismic maps versus pressure and saturation maps from the simulation model facilitates understanding of the 4D seismic. What is missing in such comparisons is the different representation of vertical heterogeneity in the maps from the seismic and simulation model domains. Unlike the maps from the simulation model, which are created using weighted averaging, the seismic response is a band-limited representation of the vertical heterogeneity and reservoir architecture, which carries the tuning and wavelet imprints. Sim2seis provides the opportunity to compare the simulation model and 4D seismic in the same domain by establishing a one-to-one relationship between the two. To investigate these effects in more detail, the 4D signature of pressure and saturation effects are modelled independently by adjusting the petro-elastic model. Figure 5.14(a) shows the synthetic 4D seismic response for only the effect of pressure and Figure 5.14(b) shows the synthetic seismic response for only the saturation changes. The average saturation and pressure maps from the
simulation model are shown in Figure 5.15. In most areas in the maps, the modelled 4D response is consistent with the maps of pressure and saturation changes; nonetheless, at a more quantitative level, although 4D seismic shows the areas where oil has been replaced by water, it is challenging to observe the displacement efficiency from the 4D seismic map. In other words it is difficult to establish a one-to-one relationship between the water saturation changes and amplitude variations on

Figure 5.14 Sim2seis analysis (2004-1996) to investigate the pressure and saturation effects separately. PEM is adjusted to exclude the saturation and pressure changes respectively. Synthetic 4D maps (SNA (monitor)-SNA (baseline) SNA: sum of negative amplitudes in T31A interval) considering: (a) only pressure changes, and (b) only saturation changes. The amplitude variations in these maps differ from the average maps from the simulation model (Figure 5.15); e.g. in some areas, the amplitude variations in the saturation-only map do not reflect the water sweep efficiency map from the simulation model; i.e. the higher hardening amplitudes do not necessarily correspond to the areas with the higher changes of water saturation. As an extreme example, a small area around I6 is highlighted (dotted circle), where the modelled 4D signal in both cases (pressure only and saturation only) shows the opposite polarity of the expected 4D signal.
the 4D map. In the area highlighted by the circle along line AB, the modelled 4D signal cannot be tied to the pressure or saturation changes. The hardening in the pressure-only map cannot be justified because, according to the simulation model, pressure only builds up in this area; likewise, the softening in this area in the saturation-only map cannot be explained, because the only process that can generate softening in the saturation-only map is the presence of gas, while based on the simulation model there is no evidence of gas in this region. To explain this contradiction, one should look at the vertical heterogeneity and the geometry of the 4D variations in the reservoir (Figure 5.16). In this area, both T31A and T31B channels are present. It is apparent that, in this region, in the T31A interval (which the 4D seismic maps represent), the 4D changes are minimal. While the T31A channel in this area undergoes a subtle pressure build up (≈4 MPa) and water sweep, the T31B channel is almost fully water swept and experiences much a higher pressure build-up (≈14 MPa). The changes in the seismic traces in this region before and after production are shown in Figure 5.16 (e-f). The imprint of the prevailing 4D changes in T31B is carried by the wavelet side lobes to the upper part of the trace (where the T31A channel is registered), as the opposite polarity. In other words, in the pressure-only map, the pressure build-up effect in T31B is represented as hardening in the 4D map from T31A; on the other hand, in the saturation-only map, the water saturation signal in T31B is replicated as an opposite polarity (softening) in the 4D map from T31A. These observations reveal the benefits of sim2seis in recognising the complexity and limitations of 4D seismic interpretation in the presence of a notable vertical heterogeneity in the reservoir. It also shows the effects of the wavelet, horizons and mapping process on the genuine 4D signal.
Figure 5.15 Average maps of (a) gas saturation, (b) water saturation, and (c) pore pressure variations from the simulation model. Height weighted averaging is used to generate these maps ($\frac{\sum p_i h_i}{\sum h_i}$, $p_i$: property in each cell, $h_i$: cell height).
Figure 5.16 The influence of variations in the lower reservoir geobodies (T31B) on the 4D maps from the upper reservoir geobody (T31A). The location of line AB is shown on the maps from simulation model (Figure 5.15). (a) NTG distribution, (b) different geobodies, (c) changes in pore pressure, (d) changes in water saturation, (e) baseline and monitor quadrature traces for pressure-only case (Figure 5.14(a)), (f) baseline and monitor traces for saturation-only case (Figure 5.14(b)). The pressure and saturation changes in T31A are minimal; the seismic waveform in T31A portrays the changes from the T31B in opposite polarity.
Figure 5.17 Sim2seis results (SNA (monitor)-SNA (baseline) SNA: sum of negative amplitudes in T31A interval); (a) 2004-1996, (b) 2006-1996, (c) 2008-1996.
5.2.1 Sim2seis result interpretation

In addition to assisting the understanding of the 4D signal, sim2seis is also used to evaluate the performance of the reservoir model against the observed 4D signal. Figure 5.17 shows the sim2seis results for 2004-1996, 2006-1996, and 2008-1996. In this section, sim2seis results are compared with the observed 4D seismic (Figure 5.18 for 2004-1996, and Figure 5.19 for 2006-1996). This information is used to update the simulation model. The actual updating of the model is beyond the scope of this thesis; however the following observations and suggestions are made following the comparison of the synthetic and observed 4D maps in different regions and time-intervals. The areas of mismatch in A1 to A5 for 2004-1996 and B1 for 2006-1996 are highlighted.

![Sim2seis results](image)

**Figure 5.18** Sim2seis results versus observed 4D seismic (2004-1996) (SNA (monitor)-SNA (baseline) SNA: sum of negative amplitudes in T31A interval); (a) observed seismic; (b) sim2seis; areas of mismatch (A1-A5) are highlighted.
Figure 5.19 Sim2seis results versus observed 4D seismic (2006-1996) (SNA (monitor)-SNA (baseline) SNA: sum of negative amplitudes in T31A interval); (a) observed seismic; (b) sim2seis; B1 is highlighted as the area of mismatch for this time step.

The observed 4D map in Figure 5.20a (area A1 of Figure 5.18) shows that water from I2 reaches a boundary (marked in red) towards the south of the field and cannot support the producer P4. Considering that well I2 has been injecting since the beginning of the field production (Figure 5.7 and Figure 5.8), this cannot be the water-flood front. On the other hand, the synthetic map (Figure 5.20b) shows that the same area is water flooded. The status of the existing transmissibility multipliers in the simulation model between geobodies surrounding I2 are shown in Figure 5.20c; although there is a no-flow boundary between geobody pair 130, 122, water reaches the south of the field through geobodies 130, 53 and 122. On a separate note, the geobody boundaries at fault F3 (113, 122), (24, 122) are open boundaries in the existing simulation model,

Figure 5.20 Comparison between the observed seismic and sim2seis; (a) observed 4D map, (b) synthetic 4D map, (c) the connectivity of the boundaries between the geobodies in the existing simulation model (d) the proposed changes for the connectivity between different geobodies.
whereas the observed 4D seismic shows that fault F3 is sealing. Based on the comparison of the sim2seis and observed 4D maps, it is proposed to modify the transmissibility multipliers by converting the boundaries between the geobody pairs (113,122), (24,122), (53,122) to sealed borders (Figure 5.20d).


In Figure 5.21a (area A2 of Figure 5.18), an extensive softening due to gas is visible on the observed 4D seismic, whereas in the synthetic seismic (Figure 5.21b) this effect is subtle and gas migrates up-dip and accumulates mainly next to the fault F1. As is shown in Figure 5.12, at earlier stages of production the strong softening signal due to gas breakout dominates the centre of the map around producers P1 and P3. By bringing the injectors I3 and I5 on line, the softening signal dims due to gas going back to solution. However, it appears that the process of the gas re-resolution in the simulation model occurs at a faster rate than in reality, and this results in the disappearance of the majority of the gas signal between 2002 and 2004 (Figure 5.12e-g). The match between the measured bottom-hole pressure and the simulation model is very poor. Improving the match to the pressure data, in conjunction with adjusting the Eclipse keyword DRSDT (the rate at which gas will dissolve into the undersaturated oil), may help to preserve more gas in this area.

![Figure 5.21](image-url) Comparison between the observed seismic and sim2seis; (a) the observed seismic shows a large softening area around P1 and P3, (b) sim2seis results do not show the softening in the highlighted areas, because the simulation model predicts that gas dissolves back into solution after introducing the injectors (I3, I5, I7) in the north of the field.

In Figure 5.22a (area A3 of Figure 5.18), the observed 4D seismic shows that the water from injector I1 reaches a boundary towards the south of the field and cannot support the producer P2, whereas, based on sim2seis results (Figure 5.22b), this area in the simulation model is water flooded. The boundary between geobody pairs (224, 276) is a flowing boundary in the existing simulation model (Figure 5.22c). It is suggested that a no-flow boundary is introduced by adjusting the transmissibility multiplier between geobodies 224 and 276 (Figure 5.22d).

The boundaries between geobodies are the turbidite channel boundaries. Both sand/sand boundaries and sand/shale boundaries exist in the simulation model. Both 3D and 4D seismic data is used to draw the boundaries between the geobodies. The dynamic reservoir signature (saturation/pressure boundaries) is used to map the sand/sand borders.

![Comparison between the observed seismic and sim2seis](image)

**Figure 5.22** Comparison between the observed seismic and sim2seis: (a) observed 4D map, (b) synthetic 4D map, (c) the connectivity of the boundaries between the geobodies in the existing simulation model; (d) the proposed changes for the connectivity between geobodies (224,276).

Based on the observed 4D seismic in Figure 5.23a (area A4 of Figure 5.18), the water front in the south of the injector I5 reaches the fault F4; however, the synthetic seismic response shows the water front in the simulation model falling behind (Figure 5.23b). A pore volume multiplier and/or permeability adjustments are recommended to match the water front.

![Figure 5.23](image-url)

**Figure 5.23** Comparison between the observed seismic and sim2seis; (a) the observed seismic shows that water front from I5 reaches the boundary in the south, whereas in (b) sim2seis results show that water front movement is slower in the simulation model.


The water sweep around injector I6 seems to be symmetric, based on the observed 4D map (area A5 of Figure 5.18 and Figure 5.24a), whereas the synthetic 4D seismic shows that the saturation signal is tilted towards the south of the field (Figure 5.24b). By looking at the vertical intersection of the simulation model in this area (Figure 5.25), water sweep is seen to be asymmetric and to up-dip towards the south of the field. The asymmetric up-dip migration of water is due to the pressure gradient in this compartment, caused by the producer P2 in the south of the field. It seems that the exaggeration of the pressure gradient in the simulation model results in an asymmetric water sweep around well I6.
Figure 5.24 Comparison between the observed 4D seismic and sim2seis; (a) the water swept zone around injector I6 is symmetric, whereas (b) sim2seis results show that in the simulation model, water is spread asymmetrically towards the south of the field, beyond the boundary (dotted line) shown on the map. Figure 5.25 shows the vertical section through the simulation model along line AB.

Figure 5.25 Vertical section through the simulation model along line AB in Figure 5.24; (a) net-to-gross, (b) change in water saturation between 2004 and 1996, (c) pore pressure at 2004. The asymmetric up-dip migration of water is due to the pressure gradient in this compartment, caused by the producer P2 in the south of the field. It seems the exaggeration of the pressure gradient in the simulation model results in an asymmetric water sweep around well I6. Reducing the transmissibility multiplier at the boundary between the two geobodies may resolve the difference between the sim2seis and the observed 4D response.

On the right hand side of producer P1, below fault F1, a softening signal is observed (Figure 5.26a, area B1 of Figure 5.19); this is because injection at well I8 was stopped in June 2004 (Figure 5.26c). The resultant pressure depletion causes gas breakout; however, the poor match to pressure data in the simulation model cannot reproduce this effect (Figure 5.26b).

![Diagram showing pressure depletion and well symbols at base](image)

**Figure 5.26** Comparison between the observed 4D seismic and sim2seis; (a) softening is observed on the right side of P1 (dotted circle); (b) no softening is modelled in sim2seis results in this area, (c) bottom-hole pressure (BHP) at I8. This well is shot in June 2004. The resultant pressure depletion causes gas breakout; however, the poor match to pressure data in the simulation model cannot reproduce this effect.
5.3 Toward in-situ petro-elastic model, a sim2seis perspective

As discussed in Chapter 2, different theories for the petro-elastic model are proposed in the literature. Validation of such models remains one of the biggest challenges in PEM calculations. As shown in Figure 5.27, three different approaches can be taken to address the consistency of PEM models: the most widely used approach is based on measurements on core samples in the laboratory. Repeat logs – where the elastic logs are acquired from the intervals that have undergone production – can also be used for such analyses; however, repeat logs are not widely available and such analyses are very limited. The third approach is based on 4D seismic analysis. It is generally acknowledged that the measurements in the laboratory environment on small core samples may not necessarily represent the in-situ behaviour of the reservoir rock and associated fluids, and therefore moving from laboratory measurements towards repeat logs and 4D seismic analysis is favourable. This is because the analysis gets closer to in-situ measurements and gives the opportunity to better investigate the effect of reservoir heterogeneity. On the other hand, the downside of such analysis is that more uncertainties are involved.

Here, the validation of the PEM theories, based on 4D seismic from a sim2seis perspective, is outlined. In this approach, different petro-elastic models are used to generate synthetic 4D responses and the comparison with the observed 4D seismic is used to check the consistency of the corresponding PEM models.
Simulation model
- Model geometry
  - Active/inactive geobody distribution (NTG)
  - Fluid contacts
  - Reservoir top and base
- Connectivity of reservoir units
- ...
- ...
- ...

Production history matching hierarchy of uncertainty

Consistency?

Observed seismic
- Noise (acquisition)
- Processing and imaging

PEM
- Dry-frame characterisation
  - Stress-sensitivity
  - Sand/shale properties
- Fluid properties
- Overburden/underburden properties

Seismic modelling
- Wavelet

Table 5-2 Hierarchy of uncertainty in updating the simulation model using sim2seis.

However, this workflow is not straightforward, because discrepancies between sim2seis results and observed 4D seismic cannot be attributed solely to the PEM models. Table 5-2 shows the hierarchy of uncertainties in the comparison of the synthetic and observed 4D seismic data. The main source of uncertainty and mismatch between the synthetic and the 4D response is the simulation model. Therefore, for sim2seis to be used for validating the PEM, ideally a history-matched simulation model and a static model highly consistent with the seismic data is required. As mentioned earlier in this chapter, the available static model for the Schiehallion Field is conditioned by seismic data and the dynamic model is moderately well history-matched to injected/produced volumes and rather poorly matched to pressure. One of the challenges in the quantitative analysis of the Schiehallion sim2seis is the different range of absolute values between sim2seis and the observed seismic (Figure 5.28); additionally the lateral variation of amplitudes in sim2seis results does not perfectly match the observed seismic. Despite these complications, some ideas
are put forward in the following sections to use sim2seis quantitatively for validating some aspects of the PEM. It is acknowledged that considering the uncertainties and limitations of the available reservoir model in this study, it is difficult to make certain conclusions about the petro-elastic models; however, the main purpose here is to show how sim2seis can be used as a quantitative tool in an alternative workflow for validation and calibration of the PEM.

![Figure 5.28](image)

**Figure 5.28** Challenges of quantitative analysis based on sim2seis: (a) observed seismic (quadrature trace) for the baseline, (b) synthetic seismic (quadrature trace) for the baseline. The seismic representation of sand-shale geobodies in the sim2seis result is generally consistent with the observed seismic and conforms to the TWT horizons from observed seismic. However, a different range of amplitudes, inconsistencies in lateral amplitude variations and the differences between the geometry of the events in relation to the horizons will be reflected on the 4D attribute maps. These are of concern in precise quantitative analysis using sim2seis. The main reason for the inconsistencies in the amplitudes is the pore volume/net-to-gross values in the simulation model. As discussed in the hierarchy of uncertainties in seismic history matching, model geometry is one the major sources of mismatch between the synthetic and the observed seismic data. Figure 7.5 shows how updating the simulation model properties improve the match between sim2seis and the observed seismic data.
5.3.1 Porosity concepts in fluid substitution

In Chapter 2, the existing choices for porosity (total, effective, movable fluid) in fluid substitution were discussed. Here, I try to validate these models based on the 4D seismic observations. Figure 5.29 shows the sim2seis results for total porosity, effective porosity, and movable fluid models. In the context of PEM validation, those discrepancies between the synthetic and observed maps caused by the simulation model are not of concern; what is important here is the limits of softening and hardening, or the balance between the warm and cold colours in the 4D maps. In the observed 4D map (Figure 5.29a), the water flood signals (in blue circles), and gas breakout signals (in red circles) represent a balanced range of amplitude; however in sim2seis results (Figure 5.29b-d), the gas breakout signal appears as a higher amplitude range compared to the waterflood signal. To make a more quantitative comparison, the histograms of the 4D maps are compared with each other (Figure 5.30). Relatively, the movable fluid model generates a more balanced histogram around zero, whereas the total porosity model generates the least balanced response. Unlike the synthetic seismic responses, the observed 4D response has a rather symmetric distribution around zero i.e. softening and hardening 4D amplitudes are balanced. The histograms for the softening are similar, whereas for the hardening, each porosity case shows a different histogram. This is because the softening is partly due to pressure build-up, in which the dry-rock moduli and the stress-sensitivity curves do not differ for different porosity cases. On the other hand, the hardening is dominantly due to water flooding and, as explained extensively in Section 2.4.4, the response is different for each porosity case. On a different note, in such analysis it is difficult to decide about the standpoint of the seismic data in the spectrum of data analysis between the soft and hard data. The symmetric nature of the observed 3D/4D seismic might also be attributed to the seismic processing algorithms; as predicted by modelling exercises, such algorithms may mask the asymmetric nature of the 4D response; in other words, the asymmetric response of the PEM might be the true response of reservoir rock to the production effects, and it should not be pushed to be matched to the observed seismic response. Although it is not addressed here, changing the fluid acoustic parameters within the uncertainty range of in-situ fluid properties may also change the balance between the pressure and saturation signatures.
Figure 5.29 PEM validation using sim2seis (SNA(monitor)-SNA(baseline); SNA: sum of negative amplitudes in T31A interval); (a) observed 4D response, (b) sim2seis result based on total porosity, (c) sim2seis result based on effective porosity, (d) sim2seis result based on movable fluid model. Water-flood signals are marked by blue circles and gas breakout signal by red circles. The movable fluid model generates the closest response to the observed 4D seismic response.
Figure 5.30 PEM validation using sim2seis. The histograms of the 4D amplitude maps (Figure 5.29) are shown here. The values around zero are excluded for better visualisation of the 4D effects. The difference in the shape of the histograms is due to the inconsistencies between the observed seismic data and the simulation model. Unlike the synthetic seismic responses, the observed 4D response has a rather symmetric distribution around zero, i.e. softening and hardening 4D amplitudes are balanced. The movable fluid model generates a more balanced signal, whereas the total porosity model generates the least balanced response.

5.3.2 Calibration of rock stress-sensitivity using 4D seismic

As mentioned in Chapter 2, one of the most challenging aspects of PEM is dry-rock characterisation. The stress-sensitivity of the reservoir rocks is the subject of ongoing research and current understanding of stress-sensitivity is greatly shaped by laboratory experiments where elastic moduli of the rock are measured under different confining pressures. Alvarez and MacBeth (2014) discuss the parameters that affect the determination of stress-sensitivity parameters. Factors that should be addressed in such analyses include statistical sampling of the cores, time-scale of the production relative to the cycle that pore pressure is cycled in laboratory, core plug damage, frequency dispersion, evaluation of the effective stress coefficient, geomechanical effects, measuring dry-rock response using the Gassmann model, the role of clays and shales, imperfect stress recovery and stress asymmetry. In a different experiment, Førre et al. (2009) observed that the seismic 4D signal due to pressure depletion in the Snorre
Field could not be modelled based on stress-sensitivity curves from the laboratory measurements on core samples. As an alternative, they used repeat well-log data to calibrate the stress-sensitivity curves. 11 wells having both a repeat formation tester (RFT) and elastic logging were used to calibrate the stress-sensitivity curves for the reservoir interval. Intriguingly, the stress-sensitivity based on RFT data does not follow the same trend as core measurements and shows weaker stress-sensitivity (Figure 5.31). The modelling based on log-derived weaker stress-sensitivity agrees better with the observed seismic (Figure 5.32 and Figure 5.33).

**Figure 5.31** Normalized elastic moduli as a function of change in effective stress; **left** normalized bulk modulus; **right** normalized shear modulus. Blue lines are derived from dry core samples and red and black lines are derived from logs (Fürre et al., 2009).
**Figure 5.32** The seismic absolute amplitude difference between the base line (1983) and 1997 seismic surveys along the well path of Well A. (a) The near offset section and (b) the far offset section. The red colours indicate amplitude increase and black indicates amplitude decrease from 1983 to 1997. The area within the black ellipse corresponds to a significant decrease in pore pressure. In this area a clear brightening is observed on the far offsets (Fürre et al. 2009).

**Figure 5.33** Synthetic seismic modelling of absolute amplitude differences based on logs from Well A. The red colours indicate amplitude increase; the blue indicates amplitude decrease from 1983 to 1997; (a) elastic framework stress effect derived from core sample measurements; (b) weaker elastic framework stress effect derived from RFT logs. The model based on core samples fails to generate the observed 4D response, whereas the model based on log data agrees with the observed 4D signal (see Figure 5.32) (Fürre et al., 2009).
Chapter 6: Sim2seis application to the Blake field

A typical laboratory based stress-sensitivity curve for sandstones is shown in Figure 5.34. Equations 5-3 and 5-4 (MacBeth, 2004) characterise these stress-sensitivity curves. In these equations, $\kappa_\infty$ and $\mu_\infty$ control the curves’ asymptote; $E_K$, $P_K$, $E_\mu$ and $P_\mu$ govern the sensitivity of the rock to effective stress variations; $E_K$ and $E_\mu$ control the intercept, and $P_K$ and $P_\mu$ control the curvature. Higher $E_K$ and $E_\mu$ result in lower intercepts and higher stress-sensitivity. Lower values for $P_K$ and $P_\mu$ result in bigger curvature in the curves. Based on these curves, the rock shows higher sensitivity to pressure build up and lower sensitivity to pressure depletion.

\[
\kappa_{dry} = \frac{\kappa_\infty}{1 + E_K e^{(-\sigma_{eff}/P_K)}}
\]
\[
\mu_{dry} = \frac{\mu_\infty}{1 + E_\mu e^{(-\sigma_{eff}/P_\mu)}}
\]

Figure 5.34 Typical shape of laboratory based stress-sensitivity curves for sandstones (MacBeth, 2004).
Figure 5.35 Evolution of the 4D signal around injectors. 4D variations in the fully flooded zone around the injector (yellow circle) can be attributed to pure pressure signal. Here it is assumed that there is no change in water saturation, temperature or salinity in the vicinity of the injector after several years of water injection.

The Schiehallion Field is close to bubble point and pressure depletion is associated with gas breakout i.e. the hardening due to pressure depletion is masked by strong softening due to the gas signal. However, the evolution of the 4D signal around injectors (Figure 5.35) might be used to calibrate the stress-sensitivity curve. As shown in Figure 5.35, 4D variations in the fully flooded zone around the injector can be attributed to pure pressure signal. Therefore, by looking at the 4D signal in the vicinity of the injectors from different monitor surveys, one can extract the rock stress-sensitivity curves. Here it is assumed that the 4D signal around injectors is only due to pore pressure changes; however, if the area is not fully water flooded, the changes in water saturation should also be taken into account. The differences between the temperature and salinity of the injected water and water around the injectors are also not covered in this study. Two injectors (I5, I3) are chosen in the Schiehallion Field to perform the analysis (Figure 5.36). Five different stress-sensitivity curves (Figure 5.37) are generated to perform sim2seis. In this figure, curve (M) represents the laboratory measurements; other curves (L2), (L1), (H1), and (H2) represent different stress-sensitivities. Equations 5-3 and 5-4 are used to guarantee that all curves conform to the laboratory measurements at pre-production stage.

\[ F'_k = \frac{E_k e^{(-\frac{\sigma_{eff}}{P_k})}}{e^{(-\frac{\sigma_{eff}}{P'_k})}} \]  \hspace{1cm} (5-3)
\[ E'_\mu = \frac{E_{\mu} \exp(-\sigma_{\text{eff}} / P_{\mu})}{\exp(-\sigma_{\text{eff}} / P'_\mu)} , \]  

(5-4)

where \( \sigma_{\text{eff}} \) is the initial (pre-production) effective stress; \( P_{\mu}^1, P_{\mu}'^1, E_{\mu}^1 \) are the stress-sensitivity parameters for the laboratory measured curve (M); \( P_{\mu}', P_{\mu}'', E_{\mu}' \) are the stress-sensitivity coefficients for curves (L2, L1, H1, H2). The stress-sensitivity parameters for these curves are summarised in Table 5-3.

**Figure 5.36** Two injectors (I5, I3) are chosen in the Schichallion Field to calibrate stress-sensitivity curves based on sim2seis analysis. The yellow circles show the area where the 4D signal is averaged around injectors. The size of this area is selected based on the signature of the 4D signal and the stability of the variations of the averaged attribute.

**Figure 5.37** Different stress-sensitivity curves. Curve (M) represents the laboratory measurements; other curves (L2), (L1), (H1), and (H2) represent very low stress-sensitivity, low stress-sensitivity, high stress-sensitivity, and very high stress-sensitivity, respectively.
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<th>$E_\mu$</th>
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<td>5.7716</td>
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<td>2.0286</td>
<td>6.3760</td>
</tr>
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<td>5.6200</td>
<td>1.0833</td>
<td>7.9700</td>
</tr>
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<td>0.7130</td>
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</tr>
<tr>
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<td>7.8680</td>
<td>0.5289</td>
<td>11.1580</td>
</tr>
</tbody>
</table>

Table 5-3 The stress-sensitivity parameters for the five curves in Figure 5.37.

Figure 5.38a and Figure 5.39a show the variation of the observed 4D amplitude versus sim2seis results based on the five different curves for well I3 and I5 respectively. To facilitate the comparison, the amplitudes are normalised to the observed 4D seismic amplitudes at 2004-1996 (the first point in Figure 5.38a and Figure 5.39a). Compared to sim2seis based on laboratory measurements, sim2seis results based on the high stress-sensitivity curves (H1 and H2) have a better agreement with the observed 4D variations. However, as can be seen in Figure 5.38b and Figure 5.39b, the simulator match to the pressure history is poor; therefore, these results cannot be firmly supported.

![Figure 5.38](image)

Figure 5.38 Stress-sensitivity calibration using sim2seis; (a) 4D amplitude variations around injector I3. The amplitudes are normalised to the observed 04-96 4D amplitude. The 4D amplitude variations are in better agreement with curve (H2); (b) poor match between measured bottom-hole pressure (BHP) and simulation model prediction.
Figure 5.39 Stress-sensitivity calibration using sim2seis; (a) 4D amplitude variations around injector I5. The amplitudes are normalised to the observed 04-96 4D amplitude. The 4D amplitude variations are in better agreement with curve (H2); (b) poor match between measured bottom-hole pressure (BHP) and simulation model prediction.

5.4 Summary

In this chapter, different levels of 4D seismic interpretation have been reviewed for Segment 1 of the Schiehallion Field in the West of Shetland Basin in the North Sea. The value of tying the 4D signal with the production data in well management and planning has been highlighted. This was followed by model-based 4D interpretation, in which the simulation model was of help in understanding the gas evolution in the reservoir model between the seismic surveys. Sim2seis was used to understand the 4D signature of the different levels of reservoir that are separated by a thin shale layer. It has been shown that due to wavelet side-lobes, the 4D signature of the lower unit can generate a false 4D signature from the upper unit, with opposite polarity. This shows the importance of sim2seis in distinguishing the genuine 4D signal and the artefacts of the wavelet side-lobes and mapping process, when generating the 4D attribute maps. By comparing the sim2seis results with the observed 4D seismic, six areas of mismatch were identified; following the reservoir process in each region and the performance of the simulation model, suggestions have been made to update the simulation model accordingly.
In two quantitative applications of sim2seis, workflows have been presented to use 4D seismic to calibrate the PEM. By going through the hierarchy of uncertainty of model update using sim2seis, the uncertainties associated with the proposed workflows have been highlighted. In the first application, sim2seis results based on different porosity models for fluid substitution (total, effective, movable fluid model, see Section 2.4.2 for more details) were evaluated against the observed 4D seismic. By comparing the histograms of the 4D maps for three cases, it is observed that the balance between negative and positive values in the histogram from the movable fluid model is closer to the observed seismic; whereas the total porosity model is in least agreement with the observed seismic. In the second application, an attempt was made to calibrate the rock stress-sensitivity curve based on the multi survey 4D seismic. This workflow is based on the assumption that in fully water flooded areas around injectors, the later monitor surveys respond purely to pore pressure variations. Sim2seis modelling based on five rock stress-sensitivity curves were generated, and average synthetic 4D amplitude variations around two injectors compared with the average observed 4D signal variations for each stress-sensitivity model. It is observed that a higher stress-sensitivity than the laboratory measurements gives a better agreement with the observed seismic. However, it should be noted that the quality of pore pressure predictions in the simulation model is poor; hence some uncertainty is associated with the conclusion regarding the rock stress-sensitivity. In Chapter 7, suggestions are made for a more robust analysis.
CHAPTER 6

Sim2seis Application to the Blake Field
6.1 Reservoir description

The Blake Field is in the North Sea about 103 kilometres from Aberdeen in the Outer Moray Firth Basin (Figure 6.1). It is operated by BG Group and owned by Talisman, BG Group, and Idemitsu. The Blake Field comprises oil and gas contained in Lower Cretaceous Captain and Coracle Sandstones. Both the Captain and Coracle Sands are deep water turbidite facies. The Blake Field comprises two parts: the Blake Channel, which is a high net-to-gross basin floor channel, and the Blake Flank with lower net-to-gross. This study is focused on the Blake Channel sands, which are thick enough to be imaged on seismic data. The geometry of the Blake Channel is shown in Figure 6.2. The field began production in 2001 from six wells, five of which were completed in the central crest of the field. To maintain the aquifer pressure support during production, two injectors into the aquifer in the North and South of the field have been injecting since the beginning of production. The pre-production seismic survey was acquired in 1992. The monitor seismic survey was acquired in 2007 after six years of production. Both vintages were reprocessed using a 4D processing workflow, in 2008. Figure 6.3 shows the Normalised Root Mean square (NRMS) (Kragh and Christie, 2002) map calculated in a window 600-1100 msec above the reservoir. The average NRMS value of 30% represents a moderate repeatability of the 4D seismic data.

![Figure 6.1 Blake Field location in the Outer Moray Firth Basin in the North Sea.](image-url)
Figure 6.2 The geometry of the Blake Channel. The appraisal wells (black), production wells (dark green), injectors (blue) and fluid contacts prior to production are shown.

Figure 6.3 Normalised Root Mean square (NRMS, Kragh and Christie, 2002) map over the reservoir. The channel boundary is shown in light blue. The NRMS is calculated within the window 600-1100 msec above the reservoir. The average value of 30% represents a good repeatability of the 4D seismic data.
6.1.1 Complications of 4D seismic data analysis in Blake

The baseline survey in Blake is rather old (1993), and has not had the benefit of dedicated 4D surveying technologies. Although the seismic acquisition in the Moray Firth area suffers from strong tides, which cause high feather in the streamers, the monitor survey in Blake was the world’s first use of Western Geico’s fully-automated vessel, source and streamer steering (Brown et al., 2011). Seismic imaging in the Blake Field is a challenge; this is due to the fact that Blake is a deep reservoir in the Cretaceous, lying beneath a thick chalk layer. In fact, the Blake Field was the site of one of the early attempts to acquire a 4D seismic survey in a reservoir beneath such a North Sea chalk layer. Additionally, the complexities in the overburden introduce some uncertainties in characterising the structure of the reservoir; in particular, characterising the top of the reservoir, and time-to-depth conversion is a challenge. The overburden complexities are associated with the eroded debris from the adjacent Halibut Horst, which stream south west in the overburden above the reservoir. As the Blake reservoir is a three-phase system, understanding the uneven movement of OWC and GOC around horizontal wells is the main challenge, due to the lack of vertical seismic resolution. The thickness of the gas cap and oil leg varies around (below and above) tuning thickness, which adds to the complexities of analysis. Here, to better understand the observed 4D response, and to evaluate the dynamic response of the simulation model from a 4D seismic perspective, a simulator to seismic modelling study is performed using the workflows explained in Chapters 2 to 4.

6.2 The petro-elastic model (PEM)

In Chapter 2, the details of the petro-elastic model (PEM) calibration were covered. In this study, PEM based on effective porosity is calibrated against two of the appraisal wells (A4 and A6). Figure 6.3 shows the location of these wells over the reservoir. To achieve the representative parameters over the field within the reservoir interval (Captain Sandstone), the optimisation is limited to this interval only. Different readings for the shallow and deep resistivity logs

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1 This section is written with collaboration of Dr. Andrew Wilson (BG Group).
show that the gas zones are mud invaded, and hence these intervals are not included in the calibration process. Figure 6.4 shows the predicted $V_p$, $V_s$ and density logs for both wells using the calibrated parameters. It should be noted that a better match to the observed $V_p$, $V_s$, and density logs could be obtained if the calibration is performed for each well separately; however, to capture the average representative parameters over the field, the calibration is performed on both wells simultaneously.

The geological model is chosen as the platform to perform the sim2seis modelling. The fluid flow simulation model is run at the same scale as the geological model. After importing the results of the simulation model into the geological model at yearly time-steps between 2000 and 2007, the calibrated PEM parameters are used to generate the $V_p$, $V_s$ and density in the reservoir grid at each time step. Figure 6.5 shows the predicted changes in acoustic impedance after six years of production, for an intersection through the geological model.
Figure 6.4 (a) the predicted $V_p$, $V_s$, and density logs for well A6 in the reservoir interval (Captain Sandstone), (b) the predicted $V_p$, $V_s$, and density logs for well A4 in the reservoir interval (Captain Sandstone). The gas cap is not included in the analysis due to mud invasion. The panel to the right shows the petrophysical evaluation based on effective porosity.
Figure 6.5 (a) the saturation profile before production from the simulation model, (b) the saturation profile after six years of production from the simulation model at the time of the monitor seismic survey, (c) sim2seis predicted P-impedance change based on the calibrated PEM. The softening is associated with movement of gas into oil, and hardening is related to the movement of oil into gas or water into oil. The softening under the oil-water contact (marked by the black arrow) is due to oil going into water. Due to relatively small pressure changes, the effect of pressure on the impedance variations is negligible.

Figure 6.6 (a) The statistical wavelet extracted from the baseline seismic cube, (b) the amplitude spectrum in the frequency domain.
6.3 Seismic modelling

The details of seismic modelling for sim2seis were covered in Chapter 4. In this study, 1D convolution is employed for seismic modelling, using a statistical wavelet extracted from the baseline seismic data (Figure 6.6). To keep consistency with the observed seismic data, the range of angle stacks is selected to be between 3 to 30 degrees. The observed seismic trace layout that contains the coordinates for in-lines and cross-lines is used to generate the synthetic traces at the same location as the observed traces. Following the proposed method for the synthetic seismic alignment given in Section 4.7, the corresponding depth surface of the geological model is tied to the interpreted two-way-time (TWT) horizon for the top of the reservoir (interpreted on the observed baseline seismic data) (Figure 6.7). The results of sim2seis before and after alignment are shown in Figure 6.7(b,c).

6.4 Static model evaluation

The consistency of the static reservoir model with the seismic data can be assessed by comparing the baseline seismic data with the synthetic seismic response of the reservoir model prior to production. Figure 6.8 shows an intersection through the reservoir model, the synthetic and the observed seismic responses. The main seismic features in the synthetic and the observed seismic sections are similar; the key events corresponding to the reservoir top, GOC, palaeo-OWC and the base of the reservoir are shown in Figure 6.8. Synthetic seismic modelling confirms that the red-over-blue signature below the top of the reservoir is associated with the presence of gas. However, the lateral extent of this signature in the synthetic response is smaller compared to the observed data (it is marked by a black arrow in Figure 6.8). It is more straightforward to generate a gas indicator attribute by looking at the quadrature sections (-90 degree phase shift). In the quadrature section (Figure 6.8c), the trough (in green) between top reservoir and the palaeo-OWC horizon is a gas indicator; therefore, by calculating the average of the negative values between the corresponding horizons to the top reservoir and palaeo-OWC, a gas indicator map is generated (Figure 6.9). The main area of the difference between the synthetic and the observed map is marked with a circle. This comparison
suggests that the gas cap could be extended further in the area between the well A6 and well A4.

![Diagram of reservoir layers and TWT data](image)

**Figure 6.7** (a) the saturation profile before production, (b) the synthetic seismic (zero-phase) response before aligning the horizon corresponding to the top of the reservoir (pink) to the corresponding observed TWT horizon, (c) the synthetic seismic (zero-phase) response after aligning the horizon corresponding to the top of the reservoir (pink) to the corresponding observed TWT horizon, (d) the observed seismic (zero-phase) section and the interpreted horizon (pink) for the top of the reservoir. Note the difference in TWT in the vertical axis between (b) and (c).
Figure 6.8 (a) the saturation profile (along inline 1020) before production, (b) the synthetic seismic (zero-phase) response and the geomodel (GM) horizons in TWT, (c) the synthetic quadrature (−90 degree phase shifted) section and the geomodel (GM) horizons in TWT, (d) the observed seismic (zero-phase) data and the interpreted horizons (solid) and the synthetic TWT horizons from the geomodel (dashed). The red trough below the reservoir top is the gas indicator. Comparing (b) and (d), the black arrow marks the area that the gas-cap extension is expected to be continued further away from well A6 towards well A4. The red arrows in (d) show the difference between synthetic (dashed blue horizon) and the observed (solid blue horizon) TWT associated with palaeo-OWC.
Chapter 6: Sim2seis application to the Blake field

The horizons from the geological model are converted to TWT based on the P-velocity from the PEM results and are shown on top of the synthetic seismic response (Figure 6.8). It is shown that the palaeo-OWC corresponds to a trough in the seismic section (Figure 6.8(b)). It is observed that compared to the observed seismic, the synthetic TWT corresponding to palaeo-OWC is underestimated away from well A6 (Figure 6.8(d)). An extension of the gas cap or a deeper palaeo-OWC in the area of mismatch will improve the match between the observed and the synthetic TWT.

It should be noted that other factors which are used in the geological model building, such as seismic imaging and time to depth conversion can also affect this analysis. Introducing a more heterogeneous overburden may also resolve some of the uncertainties associated with the seismic signature at the top of the reservoir and the extent of the gas cap. Using a pre-stack depth migration and seismic inversion might be useful to clarify some of these ambiguities.

![Figure 6.9](image1.png)

Figure 6.9 The average negative values between the reservoir top and palaeo-OWC in quadrature section (Figure 6.8c) as a gas indicator attribute map; (a) the map from the observed baseline seismic data; (b) the synthetic attribute map calculated from sim2seis result. The gas-cap seems to be extended farther away from well A6 toward well A4 (marked by a circle).
6.5 Dynamic model evaluation

As mentioned earlier, the 4D seismic response in this reservoir is a combined effect of both GOC and OWC movements after production, and it is a challenge to resolve these movements. In this section, two approaches are employed to characterise the 4D seismic response of the simultaneous GOC and OWC movements. Firstly, the simplified 4D response cubes are designed to investigate the different 4D attributes and their association with contact movements. Following these analyses, to evaluate the consistency of the fluid-flow simulation model with the observed 4D seismic responses, the results of sim2seis are compared to the observed 4D seismic response. It is shown how the static and dynamic features of the reservoir model, and also the parameters in sim2seis modelling can change the predicted 4D response.

6.5.1 4D response cubes

To gain a better understanding of the 4D seismic signature of the combined contact movements, the relative variations of GOC and OWC depths are captured by putting wedge-shaped fluid phases in a simple cube. Each position in the cube represents a scenario of a combination of different thicknesses in oil/gas/water phases. The seismic responses of the cubes are generated to show what the seismic response looks like in each scenario. Thickness variations for gas and oil phases are around the tuning thickness (≈18 m). Figure 6.10 shows the four sides of the oil saturation cube and the corresponding seismic responses. Due to this resolution limit and tuning effects, volumetric analysis may not be best approach; thus map-based analysis is chosen here. Map-based analysis has the limitation that the movement of GOC and OWC cannot be captured in a single map. Analyses show that it is difficult to extract attributes that separate the GOC and OWC responses; however, two attributes (4D time-shift for GOC and 4D amplitude) are chosen which can be used indirectly to give some indications regarding the individual contact movements.
Figure 6.10 (a) The oil saturation cube for the baseline; (b) the seismic response of the baseline cube; (c) the oil saturation cube for the monitor: the fluid contact movements are captured as fluid wedges; (d) the seismic response of the monitor cube. The key seismic features are picked as TOP, GOC, and Palaeo-OWC.

Figure 6.10(b, d) shows the main horizons (TOP, GOC, and Palaeo-OWC) in both seismic cubes. Figure 6.11 shows the time-shift map (monitor-base) of the event corresponding to the GOC. Four vertical intersections show the corresponding changes in the GOC and the OWC at different locations. It is observed that the negative time-shift is associated with the downward movement of the GOC. The 4D amplitude map (Figure 6.12) is generated by subtracting the RMS map of the baseline seismic from the RMS map of the monitor seismic. RMS maps are calculated between horizons corresponding to the reservoir top and the palaeo-OWC. The interpretation of the 4D amplitude map is not straightforward; the positive values in the 4D amplitude map mainly correspond to the upward movement of the OWC.
Figure 6.11 The map on the left shows the time-shift associated with GOC. The four vertical intersections are the schematic representation of the fluid contact movements. The downward movement of GOC is associated with the negative time-shift values. The large value of the time shifts is due to the tuning effects at gas wedge within the water leg. The decrease in velocity due to oil being replaced by gas is around 150 m/s.

Figure 6.12 The map on the left shows the 4D amplitude map. The 4D amplitude map is generated by subtracting the RMS map of the baseline seismic cube from the RMS map of the monitor seismic cube. RMS maps are calculated between horizons corresponding to the reservoir top and the palaeo-OWC (Figure 6.10(b, d)). The four vertical intersections are the schematic representation of the fluid contact movements. The positive values in the 4D amplitude map mainly correspond to the upward movement of the OWC.
Figure 6.13 Seismic sections (zero-phase) along inline 1020: (a) observed baseline; (b) synthetic (sim2seis) baseline; (c) observed monitor; (d) synthetic (sim2seis) monitor; (e) observed 4D response (monitor-base); (f) synthetic (sim2seis) 4D response (monitor-base). This includes the effects of both GOC and OWC movements. The saturation changes form the simulation model are shown in Figure 6.5.
Sim2seis is used to generate the synthetic seismic response of the reservoir model for both baseline (2001) and monitor (2007) surveys. Figure 6.13 shows the sim2seis results compared to the observed seismic data. In the following sections, the two 4D attributes that were mentioned in the 4D response cubes analyses will be discussed.

6.5.2 Sim2seis modelling - 4D time-shift response of gas-oil contact

The TWT horizon corresponding to the GOC is interpreted in both synthetic and observed seismic data. The 4D time-shift map is generated by subtracting the TWT map for the baseline GOC from the TWT map for the monitor GOC. Figure 6.14 shows the observed and synthetic time-shift maps for the GOC. The area in the south of the observed time-shift maps with a chaotic response and the areas with positive time-shift values are not reliable and are therefore are excluded from the analysis. The area of interest in the central crest is highlighted in the maps, where a negative coherent time-shift is observed, which – as confirmed in 4D response cube analysis (Section 6.5.1) – is related to the downward movement of the GOC. The results show that the synthetic time-shift (and hence the downward movement of the GOC in the simulation model) is overestimated compared to the observed map. Based on this analysis, it is suggested to update the simulation model to have less downward movement of the GOC in the central crest of the reservoir.

Figure 6.14 GOC 4D time-shift; (a) the observed map; (b) the synthetic map. Compared to the observed map, the synthetic negative values are overestimated.
6.5.3 Sim2seis modelling - 4D amplitude response

Figure 6.15 shows the observed and synthetic 4D amplitude maps. The 4D amplitude map is generated by subtracting the RMS map of the baseline seismic from the RMS map of the monitor seismic. RMS maps are calculated between horizons corresponding to the reservoir top and the palaeo-OWC. The main areas of mismatch between the observed and synthetic responses are highlighted (N1 to N3). Unlike the time-shift, which was mainly derived by GOC movements, there are different features that affect the 4D amplitude; therefore, a comprehensive evaluation is needed to capture the causes of the discrepancies. It is shown in the following sections that, apart from fluid contact movements, other less obvious parameters, such as the wavelet, the overburden properties and the initial gas cap thickness prior to production can also change the synthetic 4D response.

![4D amplitude map](image)

**Figure 6.15** 4D amplitude map; (a) the observed map; (b) the synthetic map. The main areas of mismatch (N1 to N3) are highlighted.

**N1 and N3, the effect of overburden properties on 4D response**

In these two areas there is no initial gas cap, and hence the overburden is in contact with the oil-bearing sand. For sim2seis modelling, the properties for the overburden are normally averaged within a window in the immediate overburden above the reservoir. In this case, by choice of different window lengths (25m and 50m) for averaging, the contrast between oil-bearing sand and overburden can create either a positive or a negative reflection coefficient. The
impedance difference between oil-bearing sand and overburden is very small and it is not clear if it is a high-impedance to low-impedance contrast or vice versa. The schematic impedance profile for the sim2seis modelling is shown in Figure 6.16 for two different windows. The results of sim2seis in both cases are shown in Figure 6.17. The mismatch in A2 and A3 is resolved by choosing a 50m window for averaging the overburden properties, which generates a negative reflection coefficient (Figure 6.17(c)). It should be noted that in both cases there is a strong contrast between overburden and gas bearing sand and the response in the areas with gas is not affected by the change of the overburden properties.

**N2, combination of different features**

Area N2 is the main area of mismatch in the centre of the map (Figure 6.15). The sensitivity analysis shows that the uncertainties associated with the petroelastic model are not large enough to compensate for the mismatch in this area, and as will be discussed below, there are different features that can affect the 4D response in this area.

**Gas cap thickness prior to production** can change the 4D response. Figure 6.18 shows two models with different initial gas cap thicknesses. It is shown that a thinner initial gas-cap can fix the mismatch (Figure 6.19). However, it should be noted that the GOC in the reservoir model in this area is tied to the GOC in the appraisal well A6. Nevertheless a thin (3 ft) tight sand zone exists beneath the reservoir top, which can potentially explain a thinner gas cap.

**The wavelet** can also change the synthetic 4D response. Three different wavelets are tested in this study (Figure 6.20). Wavelet A is extracted statistically from the baseline seismic cube over the whole trace, wavelet B is extracted statistically from the baseline seismic data over a limited time interval around the reservoir (1100-1350 msec), and wavelet C is extracted from a deterministic well-tie on well A6. Figure 6.21 shows that a wavelet with a wider bandwidth (wavelets B and C) can improve the match between the synthetic and the observed 4D signal in the area N2.
Figure 6.16 The impedance contrast between the overburden (OB) and the oil-bearing sand; (a) the overburden properties are averaged within a window of 25 m above the reservoir top from well A6. The overburden/oil-bearing sand contrast is low to high; (b) the overburden properties are averaged within a window of 50 m above the reservoir top from well A6. The overburden/oil-bearing sand contrast is high to low.

Figure 6.17 The effect of overburden properties on synthetic 4D response using wavelet in Figure 6.6: (a) the observed 4D response; (b) the synthetic response using a low to high contrast between overburden and the oil-bearing sand (Figure 6.16a); (c) the synthetic response using a high to low contrast between overburden and the oil-bearing contrast (Figure 6.16b). The mismatch in areas N1 and N3 between (a) and (b) is resolved in (c).
Figure 6.18 (a) The fluid phases thicknesses prior to production from the geomodel; (b) a model with a thinner (decrease about 6 m) gas-cap prior to production. The upper part of the gas-cap (grey) is a part of the overburden.

Figure 6.19 The effect of initial gas-cap on synthetic 4D response; (a) the observed 4D response; (b) the synthetic response using the geomodel geometry (Figure 6.18(a)); (c) the synthetic response using a thinner initial gas-cap (Figure 6.18(b)). The mismatch in area N2 between (a) and (b) is resolved in (c). The contact movements and the saturation profiles after production are extracted from the simulation model and are kept the same in both cases. The wavelet in Figure 6.6 is used for these analyses.
Figure 6.20 (a) Three wavelets used for sim2seis modelling: wavelet A is extracted statistically from the baseline seismic cube over whole trace, wavelet B is extracted statistically from the baseline seismic cube over a limited time window (1100-1350 msec) around the reservoir and wavelet C is extracted deterministically from a well tie at well A6; (b) the amplitude spectra of the wavelets.

Figure 6.21 The effect of wavelet on the synthetic 4D response; (a) the observed 4D response; (b) the synthetic response using wavelet A (Figure 6.20); (c) the synthetic response using wavelet B (Figure 6.20); (d) the synthetic response using wavelet C (Figure 6.20). The mismatch in area N2 is decreased using wavelets B and C, which have a wider bandwidth.
The effects of fluid contact movements are also evaluated in this area. Figure 6.22 shows two scenarios for fluid contacts after production. The first scenario (Figure 6.22(a)) is the prediction of the simulation model, and the second scenario (Figure 6.22(b)) assumes a model with higher oil-water contact movement and less downward movement of the gas-oil contact, compared to the predictions of the simulation model. The latter model is suggested based on the results of the 4D response cubes, in order to create a positive 4D amplitude response in area N2. The 4D amplitude maps (Figure 6.23) show that the second scenario can improve the match in the area. However, higher movement of OWC in this case increases the risk of the production wells in the middle of the reservoir becoming water flooded, the evidence of which is not yet observed in the production data.

![Figure 6.22](image)

**Figure 6.22** Saturation profile after production at time of monitor survey; (a) the contact movement prediction from simulation model; (b) compared to the simulation model predictions, this model has less downward shift of the GOC and higher movement of the OWC. Although this modelling addresses the seismic 4D signature at two cases, it should be noted that the changes in volumes of water and hydrocarbon due to changes in OWC should be consistent with the production data.
Figure 6.23 The effect of fluid contact movements on the synthetic 4D response; (a) the observed 4D response; (b) the synthetic response using the predictions of the simulation model for fluid contacts (Figure 6.22(a)); (c) the synthetic response using a model with less downward movement of the GOC and a higher OWC (Figure 6.23b). The mismatch in area N2 between (a) and (b) is improved in (c).
Figure 6.24 The synthetic 4D response using a combination of different fluid contact movements (Figure 6.22) and wavelets (Figure 6.20); (a) fluid contacts from the simulation model (Figure 6.22a) and wavelet A; (b) fluid contacts from the simulation model (Figure 6.22a) and wavelet B; (c) fluid contacts from the simulation model (Figure 6.22a) and wavelet C; (d) modified fluid contacts (Figure 6.22b) and wavelet A; (e) modified fluid contacts (Figure 6.22b) and wavelet B; (f) modified fluid contacts and wavelet C. The combination of the effect of the wavelet and fluid contact movements (e) and (f) can improve the match in area N2.
It is shown here that a combination of different features could fix the mismatch in area N2: a thinner gas cap prior to production, a wavelet with a wider bandwidth, less downward movement of the GOC, and higher movement of the OWC compared to predictions of the simulation model. Having less downward movement of the GOC was also supported by 4D time-shift analysis; therefore, this scenario seems to be more expected. It is very likely that a model combining these factors is the best solution. Figure 6.24 shows how the combined effects of wavelet and fluid contact movements improve the match between the synthetic and the observed 4D response.

6.6 Summary

The Blake Field is a three-phase reservoir system, and understanding the uneven movement of the oil-water contact (OWC) and the gas-oil contact (GOC) around horizontal wells is the main challenge in 4D seismic interpretation. The thickness of the gas cap and the oil leg varies around (below and above) tuning thickness, which adds to the complexity of the analysis. In this chapter, sim2seis has been used to understand the 4D signature of the simultaneous movements of the GOC and the OWC. Sim2seis also provided the opportunity to evaluate the consistency of the static reservoir model against the baseline seismic data. The seismic signature of the GOC and the palaeo-OWC from sim2seis results was compared with the observed seismic. An attribute map was generated for the presence of gas, which showed that the existing pre-production gas cap can be extended further to match with the observed baseline seismic. The corresponding TWT horizon to the palaeo-OWC from sim2seis was positioned above the observed TWT horizon; the extension of the gas cap above the horizon, or a deeper palaeo-OWC in the simulation model may resolve this mismatch.

In this chapter, two approaches were employed to characterise the 4D seismic response of the simultaneous fluid contacts movements. Firstly, the simplified 4D response cubes were designed to investigate the 4D time-shift and 4D amplitude attributes. Following these analyses, to evaluate the consistency of the fluid-flow simulation model with the observed 4D seismic responses, the
results of sim2seis modelling were compared with the observed 4D seismic response. It has been shown how the static and dynamic features of the reservoir model and also the parameters in sim2seis modelling can change the predicted 4D response. It is observed that the negative time-shift is associated with the downward movement of the GOC. The interpretation of the 4D amplitude map is not straightforward; the positive values in the 4D amplitude map mainly correspond to the upward movement of the OWC. Sim2seis results show that the synthetic time-shift (and hence the downward movement of the GOC in the simulation model) is overestimated compared to the observed map. Here, it has been shown that a combination of different features could improve the agreement between the observed and synthetic 4D amplitudes. These include a thinner gas cap prior to production, less downward movement of the GOC and higher movement of the OWC compared to predictions of the simulation model, and a wavelet with a wider bandwidth. Having less downward movement of the GOC was also supported by 4D time-shift analysis. It is very likely that a model combining these factors is the best solution. It should be noted that uncertainties associated with the seismic imaging, time to depth conversion and reservoir structure are part of the complexity in the model-based 4D seismic interpretation in the Blake Field. Quantitative seismic reservoir characterisation approaches can be used to clarify some of these ambiguities.
CHAPTER 7

Conclusions and Recommendations
Appropriate updating of the simulation models using 4D seismic data plays an important role in hydrocarbon reservoir management. Different domains can be used to assess the simulation model against the 4D seismic data, including the seismic, impedance and pressure/saturation domains. Cross-domain comparisons are widely performed in qualitative model-based 4D seismic interpretations (e.g. 4D seismic amplitude maps versus pressure and saturation maps from the simulation model). Comparison in the same domain provides the opportunity to perform detailed quantitative assessments; such comparisons can also be fed into the Seismic History Matching workflows (SHM), which allows repetitive assessment and update of the simulation model based on 4D seismic data in a semi-automated fashion. Specifically, simulator to seismic modelling (sim2seis) provides a powerful tool in bridging the gap between the simulation model and the seismic data in the seismic domain. Creating a pragmatic workflow for sim2seis was the subject of the research in this thesis. Thus, different elements of the sim2seis process were studied in detail, in order to understand the key features and limitations of this workflow in quantitative applications. What follows is a summary of the main subjects of this research, including petro-elastic model (PEM) analysis, seismic modelling for sim2seis, and two case studies highlighting the value of sim2seis in model-based 4D seismic interpretation.

7.1 PEM: Easy to implement, but should be adjusted properly.

The petro-elastic model (PEM) is the cornerstone of sim2seis analysis. It includes a few equations and parameters which are fairly easy to implement in the well-log or simulation model analysis. However, the essential and not very straightforward task is the PEM parameterisation, which was the subject of Chapter 2. Someone with less experience in this topic, may not appreciate the real value of the PEM calibration, because after all predictions of the different PEM parameterisations put the same story in the big picture: e.g. PEMs predict hardening for oil being replaced water or pressure depletion and softening for gas coming out of solution or pressure build-up (Figure 7.1 and Figure 7.2). If this is not the case, one should look for serious mistakes in their PEM settings.
Figure 7.1 Predictions of impedance changes for different PEM parameters: (a) using the calibrated parameters and suggested workflow in Chapter 2; (b) ignoring the fluid’s pressure sensitivity; (c) including the vertical saturation heterogeneity; (d) matrix-clay mixing after fluid substitution; (e) ignoring the variations of dry-rock with porosity and lithology; (f) no PEM calibration.

Figure 7.2 The error in the predictions of impedance changes for the PEMs in Figure 7.1. The error is calculated with reference to Figure 7.1(a). The error due to (a) ignoring the fluid’s pressure sensitivity; (b) ignoring the vertical saturation heterogeneity; (c) matrix-clay mixing after fluid substitution; (d) ignoring the variations of dry-rock with porosity and lithology; (e) no PEM calibration.
However, I emphasise that the main criterion to decide if a PEM is set appropriately, or in other words the main task of the PEM is not just the prediction of the expected hardening and softening, but is the ability to model the right balance between hardening and softening signals; this requires a realistic estimation of changes in elastic properties due to pressure and saturation changes. In particular, this is of crucial importance when sim2seis is implemented at a semi-quantitative level of examination. Different aspects of the algorithms that are widely used in the industry were investigated here. Gassmann’s fluid substitution model for matrix-clay mixtures was studied in a turbidite reservoir, with application to the well log data and the simulation model. Different techniques exist to include the saturation and pressure effects in the PEM based on the Gassmann equation. One can choose to calculate these effects individually and combine them at the end, e.g., calculating the changes in velocities as a function of saturation $V(S_w)$, calculating the changes in velocity as a function of pressure $V(P)$ and then combining them $PEM(V(S_w),V(P))$. However, $V(S_w)$ is a function of dry-rock elastic moduli that are pressure dependent, and it is ambiguous how the pressure dependency is dealt with by characterising saturation and pressure effects separately. In this thesis, to resolve this ambiguity and to acknowledge the physics of in-situ rock and fluid, pressure variations were embedded in the dry-rock components ($\kappa_{\text{dry}}$ and $\mu_{\text{dry}}$) of Gassmann’s model, such that its outcome ($\kappa_{\text{sat}}$ and $\mu_{\text{sat}}$) would reflect the combined effects of pressure and saturation variations. My analysis shows that the description of dry-rock elastic moduli with regard to porosity and lithology variations makes the largest contribution to predicting 4D changes; hence, the first priority in a PEM calibration is dry-rock characterisation. For this purpose, the model used in this thesis combines the effects of variations in the static properties of the reservoir (e.g. porosity and lithology) with those of the dynamic properties of the reservoir (e.g. saturation and effective stress) on the dry rock modulus. Multi-linear regression in conjunction with an optimisation algorithm was used to express the static variations of porosity and lithology in dry-rock moduli as a function of effective mineral moduli in matrix-clay mixtures.
Similar to any other rock physics study, one of the main challenges is defining the input values for PEM. The optimisation algorithm also addresses this challenge by improving the input parameters for elastic moduli of the matrix and clay components. Two models were attempted for matrix-clay mixtures in the context of fluid substitution: 1) mixing clay and matrix before fluid substitution and 2) mixing clay and matrix after fluid substitution for each component. The latter case uses sand/shale porosity concepts. However, because of the ambiguity in the definition of these terms in matrix-clay mixtures, as well as the uncertainty in the calibration of dry-rock moduli, the former approach (mixing before fluid substitution) is recommended. I reviewed the petrophysical perspective on the different porosity terms in the description of matrix-clay systems. In particular, the different components of the rock model, based on effective and total porosity, were outlined. Different porosity choices for fluid substitution (total porosity, effective porosity, movable fluid) were reviewed and applied in the well log and simulation model domains.

In Chapter 5, by comparing the observed 4D seismic data and the sim2seis results based on these models, I showed that the relative values of the seismic signature for softening (gas breakout) and hardening (water flood) signals based on movable fluids are closer to the observed seismic, whereas, the total porosity model has the least agreement to the observed 4D seismic data. On the other hand, it is observed that characterising the dry-rock model in the movable fluid model is challenging. Unlike the rock properties, characterising the fluid properties is more straightforward. The laboratory measurements of the acoustic properties of reservoir fluid are provided as a part of routine PVT measurements. The existing empirical equations (Batzle and Wang, 1992) are also reliable for a wide range of pressure and temperature variations, and modifications are available for the high pressure and high temperature cases. Based on my analysis, the pressure sensitivity of the fluid properties is found to have a small effect on the final predictions of the 4D changes. Two different fluid mixing models were analysed: 1) harmonic averaging (Domenico 1974), and 2) the model by MacBeth & Stephen (2008), which includes the small scale reservoir heterogeneity in fluid mixing. Although the model by MacBeth & Stephen (2008) predicts slightly higher impedance changes due to water
flooding, the predictions of the two approaches are very similar. The vertical scale of the reservoir model in this case \((dz \approx 3m)\) was fine enough to capture the saturation heterogeneities, and hence, the difference between the two methods is not significant.

As discussed in Chapter 3, specific consideration should be given to the application of the PEM to the simulation models. The petrophysical properties in the simulation model are distributed such that the fluid flow characteristics of the reservoir units are captured appropriately. *Pore volume* is a key parameter in this domain, and *Net-to-gross (NTG)* is introduced in the simulation model to calculate the effective pore volume in the presence of heterogeneity (i.e. clay-rich sands). Here, by going through fluid flow equations, the terms in the simulation model that were linked to the petrophysical domain are extracted and a three-component rock model was assigned to the simulation model domain. Subsequently, the link between the two domains was explored, and it was found that the effective porosity model provides a better linkage between the two domains. Considering this, and following the results of PEM modelling based on different porosity models, it is recommended that one should work on the effective porosity model throughout sim2seis. Reservoir models are made to capture the heterogeneity in the reservoir; this implies that, generally, there is more variability in lithology and reservoir properties in the reservoir models compared to the well-log data. The logs from exploration and appraisal wells are commonly targeted at good quality reservoir. Therefore, it is very likely that the lower quality reservoir rocks (and non-reservoir rocks) will be ignored at the PEM calibration stage. One may argue that it might be justified to ignore such lithologies, because the 4D signature in this portion of the reservoir is small; nevertheless, the seismic signature of the 4D signal is influenced by the geometry and properties of lower quality (and non-reservoir) material and their footprint is inherent in the final 4D attribute maps. Therefore, attention must be paid to such lithologies during PEM calibration. The PEM optimisation algorithm that was presented in Chapter 2 provides the tool for PEM calibration in heterogeneous matrix-clay systems. In fact, one area of further development for PEM is the focus on the non-reservoir or lower
quality (higher clay content) portion of the reservoir. Specifically the response of these lithologies to pore pressure variations is ambiguous and, currently, the same stress-sensitivity curves are applied throughout the reservoir. The effect of clay content on the stress-sensitivity is an interesting area of further research. HajNasser and MacBeth (2012) were able to justify an observed 4D signature by linking the clays to the pressure diffusion by considering clays to be an active reservoir material. Using the sim2seis package that is developed in this project, the seismic signature of active shales were compared with a non-active shale setting (Figure 7.3).

Simulation models are a grid representation of the reservoir, and each cell in the reservoir represents a large volume of the subsurface (100m×100m×dz). In recent years, due to the advancement of computer power and the ability to handle a large number of cells in the simulators, there is less vertical upscaling and cell heights have decreased from 10 m to less than 5 m. At larger vertical scales, the seismic signature of the simulation model deviates further from seismic signature at the log scale. The scale-related artefacts on the seismic response are unfavourable. Such effects will introduce a bias into the 4D seismic responses that cannot be linked to the production changes (saturation and pressure changes). In Chapter 3, the existing methods (scale-dependent PEM) for this issue were challenged and it has been shown that they are not
applicable for sim2seis modelling purposes. Following this discussion, I recommend performing a sensitivity analysis to find the threshold for cell height that generates acceptable results.

7.2 Seismic modelling for sim2seis

After covering different aspects of the PEM, the second major element of sim2seis – seismic modelling – was covered in Chapter 4. Two different seismic modelling approaches, “pre-stack elastic finite difference” and “1D convolution”, compared in a seismic modelling exercise. It was shown that, if the right parameterisation for 1D convolution is used, it generates very similar results to that of pre-stack finite difference seismic modelling. Using an appropriate wavelet, the distribution of CDPs and their associated angles of incidence are the key parameters to ensure an accurate seismic response. Conventional 1D convolution results suffer from lack of continuity because the migration operator (resolution function) is not included in such modelling. After application of the resolution function to the 1D convolution, the visual resemblance between 1D convolution and finite-difference (FD) results is remarkable. This function also defines the lateral resolution of seismic, and what level of detail can be extracted from the simulation model. The modelling exercise here was performed over a thin reservoir section (30-100 m). It was observed that the transmission effects, internal multiples and P to S conversions have a minimal effect on seismic results; however, these phenomena are pronounced in thick reservoirs. Following this study, an area of further research has been followed in the Edinburgh Time-Lapse Project to investigate such effects in thick stacked reservoirs (Figure 7.4). In this thesis, the full stack seismic sections are compared. One can perform this comparison for the pre-stack data and evaluate the AVO (amplitude versus offset) response of the two methods. One of the main challenges in seismic modelling for sim2seis is to extract the reservoir model interfaces at each trace location. Corner point grid systems have very complex geometries, and care must be taken to include the grid details in the right location in the reflectivity series. In this thesis, the velocity from the PEM is also used to generate the depth to time conversion for seismic modelling. This
Figure 7.4 Reflectivity method (Kennett 1979) for seismic modelling in a thick stacked reservoir; (a) baseline seismic; (b) 4D section without multiples; (c) 4D section with multiples; (d) difference between (c) and (b). (Mangriotis and MacBeth, 2013).
helps to further QC the consistency of the reservoir grid with the seismic data.

Generally, a homogeneous overburden (and underburden) is used for seismic modelling; or at best the variations in the immediate overburden are included in the analysis. This is to guarantee the right reflectivity at the top/base of the reservoir, which does not assure the correct absolute TWT of the synthetic seismic response. To be able to perform a one-to-one comparison between the synthetic and observed seismic responses, the synthetic seismic response should be aligned to the observed data. In Chapter 4, a method is proposed for the alignment of the synthetic seismic to the observed data. Once the alignment is performed, if the reservoir internal structure is consistent with the observed seismic, the interpreted TWT horizons based on the observed seismic might be used for mapping the synthetic seismic response. However, in most cases, the consistency is not good enough and one should interpret the synthetic seismic response in order to map the internal structures of the reservoir. In the last part of Chapter 4, sim2seis was used to generate the 4D response of partial stacks. These responses were compared with the individual 4D seismic signature of pressure and saturation variations. It is shown that 4D seismic for far angle stacks is saturation dominated, whereas the difference between near angle stacks and far angle stacks is pressure-dominated. This exercise can be used to calibrate the 4D inversion algorithms, based on partial stacks.

7.3 Model-based 4D seismic interpretation and sim2seis

In Chapter 5, different levels of 4D interpretation were demonstrated on Segment 1 of the Schiehallion model, and the value of sim2seis modelling in model-based 4D seismic interpretations was highlighted. The seismic signature of pressure and saturation variations was investigated and it was shown how the 4D activities in a shallow section of the reservoir were reflected in the 4D map of the upper unit by wavelet side lobes, and in extreme cases resulting in a ghost 4D signal which masked the expected 4D signature. This shows the importance of inspection of the 4D mapping process and recognising the potential wavelet artefacts. It was also shown that, although 4D seismic is successful in capturing the fluid displacement, the sweep efficiencies based on 4D seismic are not
reliable. Following these analyses, I recommend that in comparisons between the 4D seismic and the simulation model, instead of comparing the 4D seismic with the average pressure and saturation maps from the simulation model, the individual synthetic seismic signatures of pressure and saturation are to be compared with the observed 4D seismic. The PEM should be modified to exclude the effect of saturation and pressure in each case.

In this thesis, I focused on the different aspects of sim2seis and understanding the controlling parameters of the 4D signature. Although seismic history matching (SHM) was not the subject of this thesis, sim2seis is closely related to SHM applications. Therefore, to show the value of sim2seis in the model updating process, the areas of mismatch between the observed 4D maps and the synthetic 4D maps in the Schiehallion Field were highlighted. By considering the reservoir processes, recommendations were made to update the simulation model to improve the match between the synthetic seismic and the observed seismic. In addition to SHM applications, quantitative sim2seis analysis can be used to validate the PEM workflow and theories. Commonly, laboratory measurements are used to confirm the PEM predictions. However, although laboratory measurements provide accurate measurements, they are prone to some limitations, the most important of which include scale differences, complications in simulating the in-situ reservoir conditions and the absence of heterogeneity. Therefore it is intriguing to seek for alternative approaches that suffer less from these obstacles. In PEM validation based on 4D seismic data, certain parameters in the PEM are perturbed to decrease the mismatch between sim2seis results and the observed 4D seismic data. In this thesis, this technique was applied to two different aspects of PEM. In the first application, the seismic domain was used to evaluate the different choices for porosity (total porosity, effective porosity, movable fluid model) in fluid substitution. The sim2seis result based on the movable fluid model had the best agreement with the observed 4D seismic, whereas the sim2seis result based on the total porosity model had the least agreement with the observed 4D seismic. In the second application, an attempt was made to calibrate the rock stress-sensitivity curves based on the observed 4D seismic. Variations of the 4D signal in the fully-swept zone in the
Figure 7.5 Closing the loop between the simulation model and 3D seismic. (a) Observed baseline seismic; (b) synthetic seismic before model update; (c) synthetic seismic after model update; (d) pore volume before model update; (e) pore volume after model update.
vicinity of injectors were considered to be purely due to pore pressure variations. Five different stress-sensitivity curves covering a range of high to low stress-sensitivity were used to generate the sim2seis results. By comparing the variation of the 4D amplitudes during three monitor surveys, it was observed that the reservoir rock around injectors showed a higher stress-sensitivity than the measured laboratory curves. However, the inconsistencies between the simulation model and seismic data, and the poor match to pressure history data, were major issues in the validation of the PEM by 4D seismic data. Although the reservoir model in this project was fairly consistent with the observed seismic, to be able to perform quantitative analysis, and avoid normalisation of the synthetic results against the observed seismic, higher levels of consistency are required. In an attempt that is open for further developments, the static model was updated by closing the loop between the reservoir model and the 3D seismic data. Using a PEM-based seismic inversion algorithm the pore volume and the volume of clay in the reservoir model were updated. The inversion engine was based on simulated annealing (Tian et al., 2011). The PEM equations developed in Chapter 2 were embedded in the inversion algorithm. Figure 7.5 shows an intersection through the updated pore volume and the improved synthetic seismic. Although the updated model is highly consistent with the seismic data, its match to production data is very poor. For future work to be carried out, it is recommended to match the model to the production history in order to be able use the model in quantitative sim2seis analysis.

In Chapter 6, the effect of the static and dynamic reservoir parameters on the 4D signature of simultaneous movement of the OWC and the GOC in the Blake reservoir were studied. In this chapter, two approaches were employed to characterise the 4D seismic response movements. Firstly, the simplified 4D response cubes were designed to investigate the 4D time-shift and amplitude attributes associated with contact movements. It was observed that the 4D time-shift map can be linked to the downward movement of the GOC. The results showed that the synthetic time-shift (and hence the downward movement of the GOC in the simulation model) was overestimated compared to the observed 4D time-shift. It was shown that a combination of different features could improve the agreement between the observed and synthetic 4D
amplitudes. These include a thinner gas cap prior to production, less downward movement of the GOC and higher movement of the OWC compared to the predictions of the simulation model, and a wavelet with a wider bandwidth. It is very likely that a model that combines these factors together is the best solution. In these analyses, the uncertainties associated with the seismic imaging are not included. These uncertainties can change both the wavelet and the time to depth conversion that is used to build the reservoir model. For more direct quantitative results, a simultaneous multi-parameter 4D inversion algorithm can be designed which combines both the static and dynamic features of the reservoir model, as well as the modelling parameters.

7.4 Sim2seis software

A simulator to seismic modelling software package in MatLab is one of the outcomes of this research. I am glad that this package has also been used in several research projects in the Edinburgh Time-Lapse Project and the MSc programme in the Institute of Petroleum Engineering at Heriot-Watt University. For further developments, this package might be converted to other platforms to facilitate its usage and to increase the speed of the calculations. The manual for the current package can be found in the Appendix F.
APPENDIX A

Seismic Modelling Using Finite-Difference and 1D Convolution

* The contents of Section A.1 “Solving the elastic wave equation with finite-differences” are from the following document with minor modifications.

Bohlen T., De Nil D., Köhn D. and Jetschny S. 2012. SOFI3D – Seismic modeling with finite differences 3D - acoustic and viscoelastic version (user guide). Department of Physics, Geophysical Institute, Karlsruhe Institute of Technology.
A.1 Solving the elastic wave equation with finite-differences

Seismic wave propagation in linearly elastic and isotropic medium can be expressed as elastodynamic equations in terms of stress and displacement vectors. This system could be transformed into the following first-order velocity-stress hyperbolic system in terms of the particle velocities $v$, the stresses $\tau_{ij}$, the density $\rho$, the Lame parameters $\lambda$ and $\mu$:

$$\rho \frac{\partial v_x}{\partial t} = \frac{\partial \tau_{xx}}{\partial x} + \frac{\partial \tau_{xy}}{\partial y}$$

$$\rho \frac{\partial v_y}{\partial t} = \frac{\partial \tau_{xy}}{\partial x} + \frac{\partial \tau_{yy}}{\partial y}$$

$$\rho \frac{\partial \tau_{xx}}{\partial t} = (\lambda + 2\mu) \frac{\partial v_x}{\partial x} + \lambda \frac{\partial v_y}{\partial y}$$

$$\rho \frac{\partial \tau_{yy}}{\partial t} = (\lambda + 2\mu) \frac{\partial v_y}{\partial y} + \lambda \frac{\partial v_x}{\partial x}$$

$$\rho \frac{\partial \tau_{xy}}{\partial t} = \mu \left( \frac{\partial v_y}{\partial x} + \lambda \frac{\partial v_x}{\partial y} \right)$$

Finite-difference (FD) implementation

To solve the above equations, the particle velocities $v$, the stresses $\tau_{ij}$, the density $\rho$, the Lame parameters $\lambda$ and $\mu$ are calculated at discrete Cartesian coordinates $x = i \times dx$, $y = i \times dy$ and at discrete times $t = i \times dt$ on a grid. $dx$ and $dy$ denote the spatial grid point distance in $x$ and $y$ direction and $dt$ the difference between two succeeding time steps with $i \in N[1,NX]$, $j \in N[1, NY]$ and $n \in N[1, NT]$, where $NX$, $NY$ and $NT$ denote the number of spatial grid points and time steps. Finally the partial derivatives are replaced by (finite)-difference operators. The derivative of a function $y$ after a variable $x$ can be approximated by a forward $D^+$ or a backward operator $D^-$

$$D^+ x y = \frac{y[i+1] - y[i]}{dh}, \quad \text{forward operator}$$

$$D^- x y = \frac{y[i] - y[i-1]}{dh}, \quad \text{backward operator}$$
To calculate with a larger grid point distance the variables are arranged on a staggered grid (Virieux 1986) and (Levander 1988) (Figure A.1). Please note, that the vertical axis is denoted by \( Y \), e.g. the indices of the stress components are labelled accordingly. To satisfy the stability of the Standard Staggered Grid (SSG) code the density \( \rho \), respectively. The Lame parameter \( \mu \) are arithmetically and harmonically averaged (Bohlen and Saenger 2006).

![Figure A.1 Grid geometry for a Standard Staggered Grid (SSG) (Bohlen and Saenger 2006).](image)

**Accuracy of FD-operators**

In the previous section, the partial derivation was simply replaced by a finite difference quotient. In this section, a more methodical approach is used. First the first derivation of the variable \( f \) at a grid point \( i \) is calculated using the following Taylor expansion:

\[
(2k - 1) \left. \frac{\partial f}{\partial x} \right|_i = \frac{1}{dh} (f_{i+(k-1/2)} - f_{i-(k-1/2)}) + \frac{1}{dh} \sum_{l=2}^{N} \frac{(k-dh/2)^{2l-1}}{(2l-1)!} \left. \frac{\partial^{(2l-1)} f}{\partial x^{(2l-1)}} \right|_i + O(dh)^{2N}
\]

For an FD operator with length \( 2N \), \( N \) equations with a weighting factor \( \beta_k \) are added:

\[
\left[ \sum_{k=1}^{N} \beta_k (2k - 1) \right] \left. \frac{\partial f}{\partial x} \right|_i = \frac{1}{dh} \sum_{k=1}^{N} \beta_k (f_{i+(k-1/2)} - f_{i-(k-1/2)}) + \frac{1}{dh} \sum_{k=1}^{N} \sum_{l=2}^{N} \beta_k \frac{(k-dh/2)^{2l-1}}{(2l-1)!} \left. \frac{\partial^{(2l-1)} f}{\partial x^{(2l-1)}} \right|_i + O(dh)^{2N}
\]
For the case \( N = 1 \) we get the FD operator from the previous section with length \( 2N = 2 \). The Taylor series expansion will be aborted after the first term \( O(dh)^2 \). This operator is called 2\textsuperscript{nd} order FD-operator which denotes the abortion error of the Taylor series and not the order of the desired approximated derivation. To understand this equation in more detail, the coefficients for a 4\textsuperscript{th} order FD-operator are calculated. The 4\textsuperscript{th} order FD operator has the length \( 2N = 4 \), so \( N = 2 \). By calculating the sums in equation above we get:

\[
(\beta_1 + 3\beta_2) \left. \frac{\partial f}{\partial x} \right|_i = \frac{1}{dh} \left( \beta_k (f_{i-1/2} - f_{i+1/2}) + \beta_k (f_{i-3/2} - f_{i+3/2}) \right) + \frac{dh^2}{d^2 x} \left[ \beta_1 \frac{1}{8 \cdot 3!} + \beta_2 \frac{27}{8 \cdot 3!} \right] \left. \frac{\partial^3 f}{\partial x^3} \right|_i
\]

The weights \( \beta_k \) are calculated in the following way. The coefficients in front of the derivation on the left-hand side of this equation should be equal to 1:

\[
\beta_1 + 3\beta_2 = 1
\]

The coefficients before the derivation \( \left. \frac{\partial^3 f}{\partial x^3} \right|_i \) on the right-hand side are vanishing:

\[
\beta_1 + 27\beta_2 = 0
\]

The weighting coefficients \( \beta_k \) can be calculated by inverting the following matrix equation:

\[
\begin{bmatrix} 1 & 3 \\ 1 & 27 \end{bmatrix} \cdot \begin{bmatrix} \beta_1 \\ \beta_2 \end{bmatrix} = \begin{bmatrix} 1 \\ 0 \end{bmatrix}
\]

The resulting coefficients are \( \beta_1 = 9/8 \) and \( \beta_2 = -1/24 \), so the forward and backward 4\textsuperscript{th} order FD operators look like:

\[
\left. \frac{\partial f}{\partial x} \right|_{i+1/2} = \frac{1}{dh} \left[ \beta_1 (f_{i+1} - f_i) + \beta_2 (f_{i-2} - f_{i-1}) \right], \quad \text{forward operator}
\]

\[
\left. \frac{\partial f}{\partial x} \right|_{i-1/2} = \frac{1}{dh} \left[ \beta_1 (f_i - f_{i-1}) + \beta_2 (f_{i+1} - f_{i-2}) \right], \quad \text{backward operator}
\]
Appendix A: Seismic Modelling Using Finite-Difference and 1D Convolution

The coefficients $\beta_i$ in the FD operator are called Taylor coefficients. The accuracy of higher order FD operators can be improved significantly simply by slightly changes in the FD coefficients (Holberg 1987). These numerically optimized coefficients are called Holberg coefficients.

**Numerical artefacts and instabilities**

To avoid numerical artefacts and instabilities during a FD modelling run, a spatial and temporal sampling condition for the wave field has to be satisfied. These will be discussed in the following two sections.

**Grid dispersion**

The first question when building a FD model is: What is the maximum spatial grid point distance $dh$, so that the wave field is correctly sampled? To answer this question we take a look at this simple example: The particle velocity in $x$-direction is defined by a sine function:

$$v_x = \sin \left( \frac{2\pi x}{\lambda} \right)$$  \hspace{1cm} (A-1)

where $\lambda$ denotes the wavelength. When calculating the derivation of this function analytically at $x = 0$ and setting $\lambda = 1\, m$ we get:

$$\left. \frac{dv_x}{dx} \right|_{x=0} = \frac{2\pi}{\lambda} \cos \left( \frac{2\pi x}{\lambda} \right) \bigg|_{x=0} = 2\pi$$  \hspace{1cm} (A-2)

In the next step, the derivation is approximated numerically by a $2^{nd}$ order finite-difference operator:

$$\left. \frac{dv_x}{dx} \right|_{x=0} \approx \frac{v_x(x+\Delta x) - v_x(x)}{\Delta x} \bigg|_{x=0} = \frac{\sin \left( \frac{2\pi \Delta x}{\lambda} \right)}{\Delta x}$$

Using the Nyquist-criteria, it should be sufficient to sample the wave field with $\Delta x = \lambda/2$. In Table A.1, the numerical solutions of Equation A-1 and the analytical solution A-2 are compared for different sample intervals $\Delta x = \lambda/n$, where $n$ is the number of grid points per wavelength. For the case $n = 2$, which
corresponds to the Nyquist criteria, the numerical solution is $\frac{dv_x}{dx}\bigg|_{x=0} = 0$, which is not equal with the analytical solution $2\pi$. A refinement of the spatial sampling of the wave field results in an improvement of the finite difference solution. To avoid the occurrence of grid dispersion, the following criteria for the spatial grid spacing case $dh$ has to be satisfied:

$$dh \leq \frac{\lambda_{\text{min}}}{n} = \frac{V_{s,\text{min}}}{nf_{\text{max}}}$$

Here $\lambda_{\text{min}}$ denotes the minimum wavelength, $V_{s,\text{min}}$ the minimum S-wave velocity in the model and $f_{\text{max}}$ is the maximum frequency of the source signal. Depending on the accuracy of the used FD operator the parameter $n$ is different. In table A.2, $n$ is listed for different FD operator lengths and types (Taylor and Holberg operators). For short operators, $n$ should be chosen relatively large, so the spatial grid spacing is small, while for longer FD operators $n$ is smaller and the grid spacing can be larger.

| $n$     | $\Delta x$ [m] | $\frac{dv_x}{dx}\bigg|_{x=0}$ |
|---------|----------------|-------------------|
| analytical | -              | $2\pi \approx 6.283$ |
| 2       | $\lambda/2$   | 0                 |
| 4       | $\lambda/4$   | 4.0               |
| 8       | $\lambda/8$   | 5.657             |
| 16      | $\lambda/16$  | 6.123             |

Table A.1 Comparison of the analytical solution of Equation A.1 with the numerical solution (Equation A.2) for different grid spacing $\Delta x = \lambda/n$

<table>
<thead>
<tr>
<th>FD-order</th>
<th>$n$ (Taylor)</th>
<th>$n$ (Holberg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$2^{\text{nd}}$</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>$4^{\text{th}}$</td>
<td>8</td>
<td>8.32</td>
</tr>
<tr>
<td>$6^{\text{th}}$</td>
<td>7</td>
<td>4.77</td>
</tr>
<tr>
<td>$8^{\text{th}}$</td>
<td>6</td>
<td>3.69</td>
</tr>
<tr>
<td>$10^{\text{th}}$</td>
<td>5</td>
<td>3.19</td>
</tr>
<tr>
<td>$12^{\text{th}}$</td>
<td>4</td>
<td>2.91</td>
</tr>
</tbody>
</table>

Table A.2 The number of grid points per minimum wavelength $n$ for different orders ($2^{\text{nd}}$-$12^{\text{th}}$) and types (Taylor and Holberg) of FD operators.
The Courant Instability

In analogy to the spatial, the temporal discretization has to satisfy a sampling criterion to ensure the stability of the FD code. If a wave is crossing a discrete grid, then the time step $dt$ must be less than the time for the wave to travel between two adjacent grid points with grid spacing $dh$. For a 2D grid this means mathematically:

$$dt = \frac{dh}{n\sqrt{2}v_{p,\text{max}}}$$

where $v_{p,\text{max}}$ is the maximum P-wave velocity in the model. The factor $h$ again depends on the order of the FD operator. In table A.3, $h$ is listed for different FD operator lengths and types (Taylor and Holberg operators). The above criterion is called Courant-Friedrichs-Lewy criterion.

<table>
<thead>
<tr>
<th>FD-order</th>
<th>n (Taylor)</th>
<th>n (Holberg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2\text{nd}</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>4\text{th}</td>
<td>7/8</td>
<td>1.184614</td>
</tr>
<tr>
<td>6\text{th}</td>
<td>149/120</td>
<td>1.283482</td>
</tr>
<tr>
<td>8\text{th}</td>
<td>2161/1680</td>
<td>1.345927</td>
</tr>
<tr>
<td>10\text{th}</td>
<td>53089/40320</td>
<td>1.387660</td>
</tr>
<tr>
<td>12\text{th}</td>
<td>1187803/887040</td>
<td>1.417065</td>
</tr>
</tbody>
</table>

Table A.3 The factor $h$ in the Courant criterion for different orders FD-order (2\text{nd} - 12\text{th}) and types (Taylor and Holberg) of FD operators.
A.2 Seismic modelling using 1D convolution

In this section, the implementation of the seismic modelling using 1D convolution is explained. The theory of convolutional theory is covered in Yilmaz (2000). In this model, earth’s reflectivity is convolved with the seismic wavelet to calculate the seismic trace:

\[ S = RC \otimes W + n \]

\( S \) is the seismic trace, \( RC \) the earth reflectivity series, \( W \) the seismic wavelet and \( n \) is the noise component. Figure A.2 shows the workflow for 1D convolution in practice. At each CMP location within a seismic bin, the vertical pseudo-logs are extracted. At each CMP, Zoeppritz equations are used to calculate the reflectivity depth series considering the angle of incidence associated with each CMP \((RC_d(\theta_1), RC_d(\theta_2) ... RC_d(\theta_n))\). The mean reflectivity depth series (\(\overline{RC}_d\)) is assigned to the centre of the seismic bin. In practice the geometry of the CMPs within the bin is not known. Therefore, the reflectivity series are calculated using the extracted vertical pseudo-log at the centre of the bin (Inline/Cross-line location) and a range of angles of incidence. The mean reflectivity depth series (\(\overline{RC}_d\)) is converted to the reflectivity (zero-offset) tow-way-time series (\(\overline{RC}_{TWT}\)). Finally, the mean reflectivity time series and the wavelet are digitised using the same sampling interval and convolved to create the seismic trace. This algorithm is referred as one-dimensional because the zero-offset two-way-time is calculated using a vertical ray path from surface to the target. However, for accurate calculation of the two-way-times, the perturbations in ray trajectory due to the complexity in geometry and velocity heterogeneity of the subsurface should be taken into account. To include such complexities, 2D/3D ray tracing methods are implemented in more sophisticated convolution based seismic modelling algorithms.
Figure A.2 Seismic modelling based on 1D convolution at each Inline/Cross-line location (IL/XL). (a) The simplistic geometry of wave propagation through subsurface for two pairs of shot and receivers (S1, R1 and S2, R2). (b) The angle of incidence associated with all the CMPs within the seismic bin are taken into account for reflectivity calculations. (c) Reflectivity depth series for each angle of incidence is created by calculating the reflection coefficients at the interfaces of subsurface layers. The average of reflectivity series is calculated to create the angle stack response; (d) Mean reflectivity depth series is transformed to the mean reflection two-way-time series and digitised using a sampling interval. (e) The digitised mean reflectivity time series is coevolved with the digitised seismic wavelet to calculate the stacked seismic trace.
References


APPENDIX B

Resolution Limits of Seismic Data
The resolution of the seismic data in vertical (temporal) and lateral (spatial) directions is limited by its band limited nature. The resolving power of the seismic data concerns the ability of the seismic images to produce separate reflections from closely spaced interfaces and scatter points in the vertical and horizontal directions respectively.

**Temporal resolution limit: Tuning thickness**

Wedge modelling is a common practice to address the vertical resolution limits of the seismic data. As shown in Figure B.1, by comparing the apparent thickness (peak to trough) and the true thickness of the wedge, the minimum thickness below which the peak and trough are not resolvable is examined. This thickness depends on velocity and wavelet characteristics (central lobe breadth, ratio of side lobe amplitude to maximum amplitude, and length of side-tail oscillations).

![Diagram](image)

**Figure B.7** The seismic response of a wavelet convolved with two spikes of equal amplitude and opposite polarity is a composite wavelet that varies as a function of spike separation, i.e., layer thickness.
Figure B.2 shows apparent thickness (i.e., peak to trough time) and maximum absolute amplitude of the composite waveform as a function of true bed thickness for a 25-Hz Ricker wavelet for the wedge model in Figure B.1. Tuning thickness based on Rayleigh’s criterion, is the point where apparent thickness is precisely the same as true thickness (expressed in time $b/2$). It can be seen that above tuning thickness, peak to trough time measurements are good approximations of bed thicknesses, whereas below tuning thickness, amplitude information must be used.

The amplitude curve in Figure B.2 shows that at tuning thickness, composite waveform amplitudes reach a maximum equal to the sum of the maximum absolute amplitudes of the central peak and adjacent side lobe of the convolving wavelet and then decrease nonlinearly to zero. Tuning thickness ($b/2$) can be expressed in terms of predominant wavelength. The tuning thickness for a Ricker wavelet is given by

$$
\frac{b}{2} = \frac{\lambda_p}{4}
$$
\[ \lambda_p = \frac{v}{f_p} \]

where \( \lambda_p \) is the pre-dominant wavelength through a bed of interval velocity \( v \). Predominant frequency \( f_p \), is the reciprocal of the trough to trough time or breadth about the central lobe. We also note that at the true thickness separation of \( \lambda_p/8.5 \), the peak absolute amplitude of the composite waveform equals the peak absolute amplitude of the convolving Ricker wavelet.

**Spatial resolution limit: Fresnel zone**

Similar to the vertical direction, the resolution of the seismic data is also limited in the horizontal direction i.e. the seismic data cannot resolve two scatter points that are located in a distance closer than the horizontal resolution limit of the seismic data. This is due to the fact that a reflection that we think of as coming back to the surface from a point is actually being reflected from an area with the dimension of the Fresnel zone. The Fresnel Zone radius depends on wavelength (itself a function of frequency and velocity). The effect of migration can be thought of as lowering geophones through the earth until they are coincident with a reflector, at which time the Fresnel Zone will have shrunk to a small circle (Figure B.3). Chen and Shuster (1992) calculated the point scattered responses and resolution limits for both post-stack and pre-stack migrated images (Figure B.4).
Figure B.3 Three-dimensional migration collapses the Fresnel Zone to a small circle, but 2-D migration collapses it in only one direction.

Figure B.4 Point scatterer responses for both 2D poststack (top) and prestack (bottom) migrations. The geophone aperture $2L_g$ in the poststack geometry is the same as the source and geophone apertures in the prestack geometry, i.e., $2L_s = 2L_g = 3000 \text{ m}$. The wavelength $\lambda$ is 100 m (Chen and Shuster 1999).

References


APPENDIX C

Effective Elastic Media: Voigt–Reuss–Hill Average and Backus Average

* The contents of this appendix are from the following book with minor modifications.

D.1 Voigt–Reuss–Hill average moduli estimate

The Voigt–Reuss–Hill average is simply the arithmetic average of the Voigt upper bound and the Reuss lower bound. This average is expressed as

\[ M_{VRH} = \frac{M_V + M_R}{2} \]  \hspace{1cm} (D-1)

where

\[ M_V = \sum_{i=1}^{N} f_i M_i \]  \hspace{1cm} (D-2)

\[ \frac{1}{M_R} = \sum_{i=1}^{N} \frac{1}{f_i M_i} \]  \hspace{1cm} (D-3)

The terms \( f_i \) and \( M_i \) are the volume fraction and the modulus of the \( i \)th component, respectively. Although \( M \) can be any modulus, it makes most sense for it to be the shear modulus or the bulk modulus.

The Voigt–Reuss–Hill average is useful when an estimate of the moduli is needed, not just the allowable range of values. An obvious extension would be to average, instead, the Hashin–Shtrikman upper and lower bounds.

This resembles, but is not exactly the same as the average of the algebraic and harmonic means of velocity used by Greenberg and Castagna (1992) in their empirical \( V_p \)–\( V_S \) relation.

**Uses of Voigt–Reuss–Hill average**

The Voigt–Reuss–Hill average is used to estimate the effective elastic moduli of a rock in terms of its constituents and pore space.

**Assumptions and limitations of Voigt–Reuss–Hill average**

The following limitation and assumption apply to the Voigt–Reuss–Hill average: the result is strictly heuristic. Hill (1952) showed that the Voigt and Reuss averages
• are upper and lower bounds, respectively. Several authors have shown that the average of these bounds can be a useful and sometimes accurate estimate of rock properties;

• the rock is isotropic.

D.2 Elastic constants in finely layered media: Backus average

A transversely isotropic medium with the symmetry axis in the $x_3$-direction has an elastic stiffness tensor that can be written in the condensed Voigt matrix form

$$
\begin{bmatrix}
a & b & f & 0 & 0 & 0 \\
b & a & f & 0 & 0 & 0 \\
f & f & c & 0 & 0 & 0 \\
0 & 0 & 0 & d & 0 & 0 \\
0 & 0 & 0 & 0 & d & 0 \\
0 & 0 & 0 & 0 & 0 & m
\end{bmatrix}, \quad m = \frac{1}{2}(a - b)
$$

where $a, b, c, d$ and $f$ are five independent elastic constants. Backus (1962) showed that in the long-wavelength limit a stratified medium composed of layers of transversely isotropic materials (each with its symmetry axis normal to the strata) is also effectively anisotropic, with effective stiffness as follows:

$$
\begin{bmatrix}
A & B & F & 0 & 0 & 0 \\
B & A & F & 0 & 0 & 0 \\
F & F & C & 0 & 0 & 0 \\
0 & 0 & 0 & D & 0 & 0 \\
0 & 0 & 0 & 0 & D & 0 \\
0 & 0 & 0 & 0 & 0 & M
\end{bmatrix}, \quad M = \frac{1}{2}(A - B)
$$

where

$$
A = \langle a - f^2 c^{-1} \rangle + \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle^2
$$

$$
B = \langle b - f^2 c^{-1} \rangle + \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle^2
$$

$$
C = \langle c^{-1} \rangle^{-1}
$$
\[ F = \langle c^{-1} \rangle^{-1} \langle f c^{-1} \rangle \]

\[ M = \langle m \rangle \]

The brackets \( \langle \cdot \rangle \) indicate averages of the enclosed properties weighted by their volumetric proportions. This is often called the Backus average.

If the individual layers are isotropic, the effective medium is still transversely isotropic, but the number of independent constants needed to describe each individual layer is reduced to 2:

\[ a = c = \lambda + 2\mu, \quad b = f = \lambda, \quad d = m = \mu \]

giving for the effective medium

\[ A = \left\langle \frac{4\mu(\lambda+\mu)}{\lambda+2\mu} \right\rangle + \left\langle \frac{1}{\lambda+2\mu} \right\rangle^{-1} \left\langle \frac{\lambda}{\lambda+2\mu} \right\rangle^2 \]

\[ B = \left\langle \frac{2\mu\lambda}{\lambda+2\mu} \right\rangle + \left\langle \frac{1}{\lambda+2\mu} \right\rangle^{-1} \left\langle \frac{\lambda}{\lambda+2\mu} \right\rangle^2 \]

\[ C = \left\langle \frac{1}{\lambda+2\mu} \right\rangle^{-1} \]

\[ F = \left\langle \frac{1}{\lambda+2\mu} \right\rangle^{-1} \left\langle \frac{\lambda}{\lambda+2\mu} \right\rangle \]

\[ D = \left\langle \frac{1}{\mu} \right\rangle^{-1} \]

\[ M = \langle \mu \rangle \]

The P- and S-wave velocities in the effective anisotropic medium can be written as

\[ V_{SH,h} = \sqrt{M/\rho} \]

\[ V_{SH,v} = V_{SV,h} = V_{SV,v} = \sqrt{D/\rho} \]  \hspace{1cm} (D-4)
\[ V_{p,h} = \sqrt{A/\rho} \]
\[ V_{p,v} = \sqrt{C/\rho} \]  \hspace{1cm} (D-5)

where \( \rho \) is the average density; \( V_{p,v} \) is for the vertically propagating P-wave; \( V_{p,h} \) is for the horizontally propagating P-wave; \( V_{SH,h} \) is for the horizontally propagating, horizontally polarized S-wave; \( V_{SH,h} \) is for the horizontally propagating, vertically polarized S-wave; and \( V_{SV,v} \) and \( V_{SH,v} \) are for the vertically propagating S-waves of any polarization (vertical is defined as being normal to the layering).

**Uses of Backus average**

The Backus average is used to model a finely stratified medium as a single homogeneous medium.

**Assumptions and limitations of Backus average**

The following presuppositions and conditions apply to the Backus average:

- all materials are linearly elastic;

- there are no sources of intrinsic energy dissipation, such as friction or viscosity; and

- the layer thickness must be much smaller than the seismic wavelength. How small is still a subject of disagreement and research, but a rule of thumb is that the wavelength must be at least ten times the layer thickness.
APPENDIX D

Petrophysical Seismic Inversion
Motivation

As discussed in Chapter 3, pore-volume and NTG are the key parameters in the simulation model. Figure E.1(b) shows the upscaled petrophysical parameters at simulation model. Figure E.1(a) shows the petrophysical evaluation at log scale that is mapped to the simulation model grid. This shows that the distribution of the parameters in the simulation model can be updated to improve the consistency with log data. Figure E.2 shows the comparison of the synthetic seismic response the simulation model at E.1(b) and the observed seismic. For quantitative applications, the match between the synthetic seismic form the simulation model and the observed seismic needs to be improved. Therefore, it is decided to perform a petrophysical seismic inversion (Bornard, et al. 2005; Floricich et al. 2010) to improve the consistency of the simulation model with the seismic data. Figure E.3 shows the existing simulation model. The existing simulation model is qualitatively conditioned with the seismic data (Figure E.3), thus it is a good initial model for seismic inversion.

Figure E.1 The petrophysical properties from (a) log data mapped to the simulation model grid. (b) the initial simulation model, (c) the updated simulation model via petrophysical seismic inversion.
**Figure E.2** The observed seismic trace in black versus the sim2seis results for the initial and updated simulation model in red and blue, respectively.

**Figure E.3** The consistency of the initial simulation model properties with seismic data. (a) seismic colored inversion data, (b) NTG and (c) pore volume at simulation model. Although the simulation mode is conditioned with the seismic data, the misfit between the synthetic seismic from the initial simulation model and the observed seismic is large (Figure E.2).

**Inversion algorithm**

Simulated annealing is used for waveform inversion (Tian et al. 2012). PEM equations are imbedded into inversion algorithm, and pore volume and volume of shale are forming the parameter space. Wavelet from well-tie is scaled to minimize the L2norm difference between the observed (base survey) and synthetic traces at well location. Figure E.4 shows the variations of acoustic impedance with porosity and volume of shale. A moving window is used for misfit analysis. The misfit function is a combination model misfit and data misfit (Varela, et. al., 2006). By matching the interpreted TWT horizon with the corresponding TVD horizon in geomodel, the alignment problem between the synthetic and observed seismic is solved. Figure E.1(c) shows the inverted
petrophysical parameters at well location, and Figure 7.5 shows the result of inversion across a vertical section through the simulation model.

Figure E.4 The variations of acoustic impedance with porosity and volume of shale.

References

Bornard, et. al., 2005, Petrophysical Seismic Inversion to Determine More Accurate and Precise Reservoir Properties, SPE 94144-MS.

Floricich et. al., 2010, Probabilistic Seismic Inversion of a West of Shetlands Deepwater Turbidite Field, 72nd EAGE Conference and Exhibition.

Tian S. and MacBeth C. 2012. An engineering-consistent inversion of time-lapse seismic data. 74th EAGE meeting, Copenhagen, Denmark, Expanded Abstracts.

APPENDIX E

Simulator to Seismic Modelling
Software Manual
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Appendix AA1 – Function Library
Appendix AA2 – MATLAB Quick Guide
If you would like to skip the introduction and start the tutorial, you need to go through the following sections:

- Section A2-4
- Section A2-5
- Chapter A3
- Chapter A4
- Chapter A5
- Chapter A6
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Chapter A1

New Developments
New Developments – V 2011.1

The major improvements and modifications for this release of the code include:

- Improvement over pseudo-log extraction.
- The option for depth trends for shale and inactive cells is added to sim2imp module.
- Eclipse extract code is modified for large number of time-steps.
- Mapping seismic attribute to the simulation grid. This option is added to 1D convolution module.
- Modifying the SEGY export.
- An option is added for removal of the time-shift between the synthetic seismic surveys.

New Developments – V 2009.2

The major improvements and modifications for this release of the code include:

- Modification over DGAS option.
- Saturation data will also be exported as the results of PEM.
- Improvement over pseudo-log extraction.
- Improvement over TWT calculations in case if an external wavelet is used.
- An option is added to align the synthetic seismic and TWT horizons to the observed seismic.
- Correction for timing of SEGY file.
- An option is added which allows user to generate seismic in selected area of interest.
- An option is added to use the trace layout from the observed seismic.
New Developments – V 2009.1

Major improvements are made over the first release of ETLP sim2seis package in March 2006. These changes are made for more robust results and ease of use for the user. The current package has been tested over several datasets, and proved to cover the challenges that one may face in real life models. The major improvements include:

- Technical and coding bugs are modified.
- The structure of the package has totally changed. A vast modification on the structure of the sub-functions is made.
- Significant improvement over the arrays and loops handling to speed up the code.
- Improvement over the debugging tools and error handling.
- More options on the petro-elastic parameters visualization in Petrel.
- Convolution preparation step (which was previously a separate package) is embedded inside the simulator to impedance module.

- 1D convolution calculation is developed:
  - Very accurate pseudo-log extraction tool, which can deal with the complexities of corner point gridding in simulation models, such as side walls of the cells, pinch outs, faults, and non-vertical pillars.
  - The regular seismic bin grid is generated independent of the simulation model grid.
  - Use of external wavelet is available.
  - Allows user to extract two-way-time horizons in ASCII format, which can be visualized in Petrel on top of seismic cube.
Chapter A2

Overview
&
Tutorial Dataset
Structure of Sim2Seis Workflow

Figure A2.1 shows the schematic structure of the ETLP simulator to seismic workflow. It comprises of the following modules in order of priority:

1- ETLP Eclipse extraction module.
This module which is written in FORTRAN 77, extracts the simulation model parameters in ASCII format which is needed for sim2seis modeling. A configuration file is required for initial setting of this module. The extracted simulation parameters include grid coordinates, static parameters (such as porosity, NTG, SATNUM, ACTNUM, and pore volume) and dynamic parameters (such as pressure, saturation of different phases, and gas oil ratio) for all specified time-step.

2- Sim2seis module.
This is a very small piece of code in MATLAB which is an interface to link the main modules 3, 4-1 and 4-2 together. In fact, this module is the core of sim2seis, where by setting a configuration file the user manages and executes the other modules.

3- Simulator to impedance (sim2imp) modeling module.
This module which is written in MATLAB, performs the petro-elastic modeling using a configuration file wherein required setting for PEM are specified.

4- Seismic modeling module:
4-1 Pseudo-log extraction module.
This module is written in MATLAB. This module extracts the vertical pseudo-logs at location of each CMP in the seismic grid. The geometry pf the seismic grid is set in the sim2seis configuration file.

4-2 1D convolution module.
This module is written in MATLAB, and performs 1D convolution. It also has the capability of exporting TWT horizons from simulation model in ASCII
format. A configuration file should be supplied for parameterizations of the convolution.

⚠️ Each module is a prerequisite for the succeeding step(s) and you will get an error if the output(s) of one module are not available for the next module(s). Figure A2.1 shows how outputs of each module are input(s) for next modules.

⚠️ The only task of user is to set the configuration files.
Figure A1.1 Four modules in Sim2Seis workflow. Module 2 (Sim2seis) is the core of the workflow, which manages the other MATLAB modules (3, and 4) in the background. The only task for user is to set the configuration files marked with 🗂️.
Structure of Sim2Seis Package

Sim2Seis package is available at http://www.pet.hw.ac.uk/research/etlp. It includes two zipped folders. Download ETLP_4DModeling.zip and Tutorial_DataSet.zip and extract the files.

- \Tutorial_DataSet
- \ETLP_4DModeling

\Tutorial_DataSet contains the tutorial dataset that will be described in section 2-4. \ETLP_4DModeling contains the sim2seis package. The structure of this directory is shown in Figure A2-2. There are four sub-folders in \ETLP_4DModeling:

- \ETLP_4DModeling\Sim2Seis_Doc
This folder contains this manual (ETLP_Sim2Seis_Manual.pdf), as well as configuration files in HTML format

- \ETLP_4DModeling\Source
This folder contains the source codes for different modules. It’s recommended not to modify this folder and its subfolders. The contents of this folder will be discussed in detail in the subsequent chapters.

- \ETLP_4DModeling\Input_Settings
This folder contains input files and also the configuration files for modules 2, 3, and 4-2. Configuration files are the files which are needed to be modified by user. These configuration files are MATLAB [*.m] files and contain the settings for each module.

[NAVID_sim2seis_config.m]
[NAVID_sim2imp_config.m]
[NAVID_conv1D_config.m]

- \ETLP_4DModeling\Output
This folder is initially empty and the results of sim2seis will be stored here.

⚠️ It’s recommended not to change the names for folders and functions. If it’s required to change the name of files or folders, it’s strongly recommended no to use space ‘ ‘ as a character in file or folder names.
Make sure that there is no repeated files in any folder, and make sure there is only one copy of each file in \ETLP_4DModeling and its subfolders e.g. [HorizonExtraction.m] cannot be in both \Sim2Imp and \LogExtract directories. In case of any repeated files in different folders you may end up with erroneous results.

![Diagram](image.png)

**Figure E.2** Structure of \ETLP_4DModeling. The contents of folders marked in red will be (manually or automatically) updated during the process.

![Diagram](image.png)

**Figure E.3** Structure of sim2seis tutorial dataset.
Required Software for Sim2seis

Sim2seis is compatible with Eclipse 100 fluid flow simulation models. You can launch Eclipse using either Eclipse launcher or via Petrel. To run simulation using Eclipse launcher:

1- Load Eclipse launcher and press Eclipse

2- Brows to the directory which includes the *.DATA file and press RUN to loud the simulator.

Before running the simulation model, make sure that all the necessary keywords to generate Eclipse formatted outputs are included in the *.DATA file (see Chapter A3), otherwise simulation results cannot be used for sim2seis.
We use Eclipse 2007.2 for fluid flow simulations. However, as we use standard Eclipse commands, older versions of Eclipse may also be appropriate.

Petrel

In addition to all other capabilities, Petrel is a powerful visualization tool and it is used to visualize most of sim2seis results. As well as the results of simulation model, the results of petro-elastic modeling (sim2imp), synthetic and observed seismic cubes, and TWT horizons are all visualized in Petrel.

Petrel 2005, 2007, or 2009 can be used for sim2seis results visualizations.

Formatted Eclipse results cannot be visualized in Petrel 2005. If you have access only to Petrel 2005, it’s recommended that in addition to formatted results (which is needed for sim2seis), generate unformatted results, then you
can upload simulation results into PETREL. See Chapter 3 for more information about formatted and unformatted ECLIPSE results.

MATLAB

The scripts for Sim2Imp, pseudo-log extraction, 1D convolution codes, and sim2seis interface (modules 3, 4-1, 4-2, and 2) are written in MATLAB. Whilst MATLAB is not the best language for numerical 'work-horse' applications (especially for loops), it is very useful for research purposes. The high level scripting language makes it easy to implement new ideas quickly and its graphics capabilities make it very easy to graphically QC the results without the need of a third party visualization software. A quick guide for MATLAB is provided in Appendix AA3.

The MATLAB scripts ETLP_4DModeling\Source can be (and should be) stored in a separate directory to input/output data. The scripts can be accessed at any time by using the MATLAB 'addpath' command. Please consult MATLAB help for more information.

MATLAB variable names must begin with a letter, which may be followed by any combination of letters, digits, and underscores. MATLAB distinguishes
between uppercase and lowercase characters, so ‘A’ and ‘a’ are not the same variable.

⚠️ When naming a variable or script, make sure you are not using a name that is already used as a function name, either one of your own M-file functions or one of the functions in the MATLAB language. All created functions within sim2seis package are listed in Appendix 2.

⚠️ You need to install MATLAB R2008, or MATLAB R2009. To be consistent with MATLAB R2007, Sim2Seis package needs very slight modifications. Please let us know if you have access only to MATLAB R2007. No extra toolboxes, Simulink or other MathWorks products are needed.

### g77 FORTRAN

The scripts for ETLP ECLIPSE extraction (module 1) are written in FORTRAN 77. Among all different available FORTRAN compilers we use g77 FORTRAN which is a free compiler. For Linux, Windows XP, or Windows VISTA you can download this compiler from [http://www.neuralwiki.org/index.php?title=Fortran](http://www.neuralwiki.org/index.php?title=Fortran)

⚠️ In Linux, to check if g77 is already installed on your machine, open a terminal window and execute the following command:

```matlab
>> which g77
```

If it is installed, you will get a message which is the access path to the source of the software e.g.

```matlab
>> user/bin/g77
```

And if it is not installed, you will get the following message

```matlab
>> user/bin/which: no g77 in (the list of directories in which g77 is not found)
```
To run a FORTRAN code using g77 open a terminal window and change the directory to the directory which contains the script [code.f], and then type

```bash
$ g77 code.f -o output.x
```

This will generate an executable file `output.x`, now to run the code type

```bash
$ ./output.x
```

For more help on FORTRAN consult with your IT support.
Tutorial Dataset: Navid Model

As stated previously, sim2seis package is available at http://www.pet.hw.ac.uk/research/etlp. Download the zipped folder ETLP_4DModeling.zip. When you extracted the zipped file, it contains a folder \Tutorial_DataSet. Here you can find the synthetic model Navid which is designed for this tutorial. General description of this model is given in Table A2.1. The simulation model and the results for the different moduli of sim2seis process are provided. The structure of this folder is shown in figure A2.3. It includes the following subfolders:

- \Tutorial_DataSet\Navid_Sim
  This folder contains the simulation results from Eclipse. Figure A2.4 shows the uploaded results of simulation from year 2000 to 2005 into PETREL.

- \Tutorial_DataSet\Navid_EclipseExtract
  In this folder you can find the results of ETLP Eclipse extract code, as well as the configuration file needed for this module.

- \Tutorial_DataSet\Navid_Sim2Seis
  This folder contains the sim2seis configuration file and report file.

- \Tutorial_DataSet\Navid_Sim2Imp
  The configuration file and petro-elastic modelling results for the model for this module.

\Tutorial_DataSet\Navid_LogExtract
You can find the results for pseudo-log extraction and its report file in this folder.

- \Tutorial_DataSet\Navid_1DConv
  This folder contains the configuration file, the results for 1D convolution, its and report file.
Sim2seis process is laid out from the beginning to the end in Chapters A3 to Chapter A7 using this dataset. In section A2-5 the detailed workflow for Sim2Seis is explained.

<table>
<thead>
<tr>
<th>reservoir dimensions</th>
<th>$2320 \times 2235 \times 35$ (average thickness) meter</th>
</tr>
</thead>
<tbody>
<tr>
<td>depth</td>
<td>1960 meter</td>
</tr>
<tr>
<td>cells</td>
<td>$60 \times 54 \times 20$</td>
</tr>
<tr>
<td>number of horizons</td>
<td>21</td>
</tr>
<tr>
<td>average Xinc</td>
<td>30.5 meter</td>
</tr>
<tr>
<td>average Yinc</td>
<td>30.5 meter</td>
</tr>
<tr>
<td>average Zinc</td>
<td>1.8 meter</td>
</tr>
<tr>
<td>simulation scenario</td>
<td>water injection into an aquifer from year 2000 to 2005</td>
</tr>
<tr>
<td>well combination</td>
<td>1 injector, 2 producer</td>
</tr>
<tr>
<td>oil API</td>
<td>25</td>
</tr>
<tr>
<td>temperature</td>
<td>136 degF</td>
</tr>
<tr>
<td>salinity</td>
<td>18000 ppm</td>
</tr>
<tr>
<td>gas gravity</td>
<td>0.586</td>
</tr>
<tr>
<td>number of SATNUM</td>
<td>1</td>
</tr>
<tr>
<td>matrix bulk modulus</td>
<td>29.1 Gpa</td>
</tr>
<tr>
<td>(sand)</td>
<td></td>
</tr>
<tr>
<td>matrix density (sand)</td>
<td>2659 Kg/m$^3$</td>
</tr>
<tr>
<td>shale [Vp, Vs, density]</td>
<td>[2738, 1222, 2342]</td>
</tr>
</tbody>
</table>

Table E.1 General description of Navid model.

Figure E.4 Navid simulation model from year 2000 to 2005.
Plan: In this tutorial we are going to use Navid model to

- Run Eclipse simulation for 6 years (2000-2005), and generate reports on following dates:
  (01 Jan 2000), (01 Jan 2001), (01 Jan 2002),
  (01 Jan 2003), (01 Jan 2004), (01 Jan 2005)

- Extract ETLP format files for the following dates:
  (01 Jan 2000), (01 Jan 2002), (01 Jan 2003),
  (01 Jan 2004), (01 Jan 2005)

- Perform petro-elastic modeling on the following dates:
  (01 Jan 2000), (01 Jan 2002), (01 Jan 2003),
  (01 Jan 2004), (01 Jan 2005)

- Generate seismic cubes for the following dates:
  (01 Jan 2000), (01 Jan 2002), (01 Jan 2004),
  (01 Jan 2005)

Running the Code (workflow)

Figure A2.5 shows the workflow and steps to run the codes in more details. In Chapters A3 to A7, this workflow is outlined step by step for calculating the synthetic seismic for Navid model.
Figure A2.5. Workflow for Sim2Seis package.
Appendix E: Simulator to seismic modelling software manual

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run Sim2Imp = 1
run log extraction = 0, 1
run 1D convolution = 0, 1

1

exist *.etlpgrid = 1
exist *.etlstat = 1
exist *_?.etlpdfyn = 1

no

2

run log extraction = 1
exist *EM_?.MAT = 1
exist *LE_?.MAT = 1

no

3

exist *.etlpgrid = 1

no

exist *.etlpgrid = 1

no

sim2imp configuration (*.m file)

yes

OK

calculations

no

yes

1D conv configuration (*.m file)

no

yes

* ?.MAT
* ?.PETREL
* EM_?.MAT
SIM2IMP_REPORT.txt

* ?.MAT
* ?.SEGY
* ?.TWTHorizon
CONV1D_REPORT.txt

* LE_?.MAT
LOGEXTRACTION_REPORT.txt

SIM2SEIS_REPORT.txt

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Appendix E: Simulator to seismic modelling software manual

Chapters A3 to A8 are only available to the members of Edinburgh Time-Lapse Project consortium. Please contact Prof. Colin MacBeth for more information (Colin.MacBeth@pet.hw.ac.uk).
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