Importance of anisotropic rock physics modelling in integrated seismic and CSEM interpretation

Michelle Ellis,1* Franklin Ruiz,1 Sriram Nanduri,1 Robert Keirstead,1 Ilgar Azizov,1 Michael Frenkel1 and Lucy MacGregor2 discuss how compositional and structural features of the subsurface rock strata at different length scales affect the elastic and electrical properties and induce anisotropy. Rock physics models are presented which calculate elastic and electrical anisotropy from the volumetric fractions of solids and fluids in the rock, and the microstructural information within the rock.

Shale comprises about 75% of the clastic fill of sedimentary basins (Jones and Wang, 1981). Shales in particular tend to exhibit high levels of elastic and resistivity anisotropy (Ellis et al., 2010a). The degree of anisotropy depends on the type and volumetric fractions of the constituents of the rock and on the size and orientation of rock fabric heterogeneities compared to the length scale of measurement. The effective elastic and electrical properties of rocks depend on the volumetric fractions of the rock’s solid and fluid constituents and on the rock’s microstructure. Different constituent and microstructural features affect elastic and electrical properties in different ways and to varying degrees. For instance, the difference in the elastic properties of a host solid matrix with connected and disconnected conductive fluid fractures is not as large in a relative sense as the difference in electrical resistivity, where fluid connectivity is one of the most significant controlling parameters. On the other hand, a small amount of initial grain cement does affect electrical properties, but not to the same extent as it affects elastic properties.

Typically, elastic wave travel times are measured at three different timescales: seismic (~40 Hz), well log (~10 kHz), and laboratory (~1 MHz). Resistivity is also typically measured at different scales, 2–1000 Hz in the laboratory, >20 KHz in the well log and ~1 Hz for controlled source electromagnetic (CSEM) surveying. Even though at seismic and CSEM scales a large percentage of sedimentary rocks are anisotropic, most data processing workflows assume that the medium is isotropic. Anisotropy results from spatial variation of the shale constituents and texture. Some of the dominant shale fabric features responsible for the observed laboratory anisotropy are: a) bedding, b) alignments of silt grains, flaky floculated clay particles, and layers of organic material, and c) alignment of fracture sets with different orientations. In sedimentary basins, layers, fractures, and grains may occur with different distributions of thicknesses, fracture dimensions, and grain sizes at different length scales, inducing different degrees of anisotropy at different length scales.

Overlooking elastic anisotropy leads to misplaced seismic reflectors, unfocused seismic imaging, incorrect well-ties, and inaccurate quantitative seismic interpretation (e.g., AVA and seismic inversion). On the other hand, disregarding resistivity anisotropy may lead to misleading CSEM survey feasibility studies, inaccurate CSEM data inversion, inaccurate estimations of hydrocarbon saturations and, consequently, erroneous interpretations. It is also difficult to ground truth CSEM data using well logs without an understanding of anisotropy. CSEM is sensitive to both vertical and horizontal resistivities. To accurately assess hydrocarbon saturation, one should apply saturation models taking into account the resistivity anisotropy. Whereas logging tools that measure both horizontal and vertical resistivity are available, they are not commonly deployed. This is especially true in the overburden section, where electrical anisotropy can significantly affect the CSEM response. For accurate integrated quantitative seismic and CSEM interpretation, it is necessary to develop techniques to estimate all the unmeasured elements of the elastic and resistivity tensors from the commonly measured elements. This can be done using rock physics models based on density, sonic, and resistivity (horizontal) log data, which are consistent with the available microstructural information (e.g., from scanning electron microscope images, thin sections, cuttings, cores, and outcrops).

In this study methods are presented to estimate the unknown elements of the rock’s elastic and resistivity tensors such as, but not limited to, shale using rock physics models,

1 RSI, 2600 South Gessner, Suite 650, Houston, Texas 77063, USA.
2 RSI, The Technology Centre, Aberdeen Science and Energy Park, Claymore Drive Bridge of Don Aberdeen AB23 8GD, UK.
* Corresponding author, E-mail: michelle.ellis@rocksolidimages.com
Anisotropic rock physics models

Elastic rock physics model for VTI layers

The elastic properties of vertical transverse isotropic (VTI) shale is estimated using a hybrid rock physics model. The model assumes that the solid shale matrix (host) is isotropic, with all solid constituent grains (e.g., clays, silt, and kerogen) randomly oriented and distributed through the host. The rock physics model divides the total pore space ($\phi_{\text{total}}$) into two spaces: the stiff pore space (stiff porosity) and the soft pore space (soft porosity). Stiff porosity ($\phi_{\text{stiff}}$) is defined as the volumetric fraction of pores with an aspect ratio of $\alpha_{\text{stiff}} = 1$ (spheres) and soft porosity ($\phi_{\text{soft}}$) is defined as the volumetric fractions of pores with a variable aspect ratio $\alpha_{\text{soft}}(\text{depth})$ (Ruiz and Cheng, 2010; Ruiz and Azizov, 2011). $\alpha_{\text{soft}}$ is usually very small, often considerably less than 0.1 (crack-like pores).

In this study, the spheroidal soft pores (e.g., microcracks) are assumed to be preferentially oriented in the horizontal direction, with the microcracks planes parallel to the vertical axis. To account for the effect of brine- or hydrocarbon-saturated stiff and soft pores on the elastic moduli, we apply a two-stage approach. In the first stage, the model estimates the elastic moduli of an isotropic rock matrix with embedded stiff fluid-saturated pores, using the self-consistent approximation (Berryman, 1995). In the second stage, Hudson’s model (Hudson, 1980) is used to estimate the elastic moduli of the material from the first stage with embedded crack-like fluid-saturated pores. The unknown elements of the rock’s elastic tensor, C11, C13, and C66, are estimated from the known elements, C33 and C44, which are calculated from the vertical P- and S-wave velocities and densities. The model assumes that micro-cracks, below well-log resolution, are the main source of elastic anisotropy and that they are preferentially oriented in the horizontal direction. This is conducted by searching for the required $\phi_{\text{soft}}$ and $\alpha_{\text{soft}}$ that minimize the difference between the measured vertical sonic S- and P-wave velocities ($V^s_{\text{obs}}$ and $V^p_{\text{obs}}$), and the theoretical vertical velocities ($V^s_{\text{the}}$ and $V^p_{\text{the}}$). The two parameters, $\phi_{\text{soft}}$ and $\alpha_{\text{soft}}$, are determined at each well log depth measurement.

Electrical anisotropic effective medium model

While there are a number of empirical electrical rock physics models that include components such as clay, including the Simandoux (1963), Waxman and Smits (1968), and Juhasz (1981) methods, there are very few that can calculate resistivity in differential directions. Effective medium models that can do this include the different effective medium (DEM) model (Bruggeman, 1935; Sen et al. 1981; Berryman, 1995), the self-consistent approximation (SCA) (Bruggeman, 1935; Landauer, 1952; Berryman, 1995) and the geometric path length (GPL) model (Ellis et al., 2010). The DEM method we use in this study models an effective medium by starting with a medium composed of a single material, to which inclusions with a known geometric shape are incrementally added. After each incremental addition the effective conductivity is recalculated. This process continues until the desired volume fraction of each constituent is reached (Figure 1). The DEM equation can be given as (Gelius and Wang 2008):

$$d\sigma = \sum_{j=1}^{N} d\sigma_j (\sigma_j - \sigma) K_j$$

Figure 1 Left: DEM model construction (adapted from Sheng, 1991). Right: DEM model path dependence.
where $\sigma$ is the conductivity of the effective medium, $\sigma_j$ is the conductivity of inclusions, and $K_j$ is a geometric factor, which is dependent on inclusion aspect ratio and inclusion alignment.

In DEM the components are not treated symmetrically. Therefore, if a calculated effective medium starts with brine and quartz is incrementally added, it will not predict the same results as if it had started with quartz and brine were incrementally added, even if the volume fractions of the two components are the same in the final effective medium (Figure 1). The DEM method preserves the microstructure of the starting medium (Sheng, 1990). It follows that if the starting medium is brine it will remain interconnected at all porosities and all other components will remain isolated. Therefore, care must be taken when deciding which component forms the background medium. Figure 1 shows the effect of the path dependence of the DEM model for an effective medium where the inclusion aspect ratio is 0.5. When the fluid is fully interconnected the effective resistivity is low and when the fluid is isolated the effective resistivity is high.

To determine vertical and horizontal resistivity from a well log it is assumed that the grains are fully aligned. Horizontal resistivity (R_h) is therefore lower compared to vertical resistivity (R_v) and the sediments are transversely isotropic. The horizontal resistivity is calculated from the porosity and the mineral volumes at every measurement point throughout the sediment column. The DEM model is adjusted so that the calculated horizontal resistivity trend matches the log measured resistivity trend. This can require changing the background constituent in the DEM calculation. Once this is conducted, the same model is used to calculate the corresponding vertical resistivities.

**Upscaling**

**Upscaling the elastic moduli and bulk density to seismic wavelengths**

At log scale, all formations are assumed to be elastically isotropic except the target shale intervals which are assumed to be transversely isotropic. The isotropic intervals are characterized by the vertical P- and S-wave velocities (C33 and C44) and density, and the anisotropic intervals (shale intervals) by five elastic moduli (C33, C44, C11, C13, and C66) and density. The sonic velocities are assumed to be known (or measured) in the principal coordinate system of the elastic tensor of the rock. The axis of symmetry is assumed to be vertical.

The upscaling process begins by assuming that the medium is vertically heterogeneous, and laterally homogeneous (layered), in the region of seismic simulation. If the horizontally layered medium is statistically homogeneous in a vertical interval $L$, it behaves like a homogeneous VTI medium for wavelengths greater than $L$ (Backus, 1962). This is valid for periodic and non-periodic isotropic and/or transversely isotropic layers. If we treat the subsurface rock strata as a stack of fine isotropic and VTI layers with thicknesses of 15 cm (assumed well-log spatial sampling interval), then Backus averaging (BA) can be used to upscale the well-log scale elastic moduli to seismic wavelengths. The Backus theory assumptions imply a relationship between the dominant seismic wavelength ($L_{dom}$) and the averaging window length $L$, which is given as,

$$L \leq L_{dom} / N = V_r^{(min)} / NF_{dom} \cdot V_r^{(min)} \text{ is the minimum S-wave velocity (vertically polarized shear velocity in a VTI medium), } F_{dom} \text{ is the dominant frequency, and } N \text{ is a positive integer to be chosen. The selection of } N \text{ depends on the purpose of the application. For the calculation of synthetic seismograms, preserving essential aspects of the seismic wavefield, } N = 3 \text{ produces a reasonable level of accuracy (Helbig, 1984; Liner and Fei, 2007). The averaging window length used in this study is } L = V_r^{(min)} / 3F_{dom}. \text{ In a VTI medium, } V_r^{(min)} \text{ is determined from the sonic shear velocity and } F_{dom} \text{ is the dominant frequency used in the simulations or, if available, from the measured seismic gather. The upscaled velocities are determined from the upscaled elastic moduli, and the arithmetic average of the density log using a running window of length } L.$$

**Upscaling electrical resistivity data using thin layers**

To upscale the resistivity measurements at well-log scale, to measurements at CSEM scale, we use the method developed by Ellis et al. (2010a). The seismic upscaling assumptions may also be applied to resistivity. In this case, the layered stratigraphic column can be treated as a set of resistors. These resistors may be connected in series or in parallel, depending on the direction of the current (Figure 2). To upscale the well-log resistivity data, each well-log resistivity measurement point is considered as a separate thin layer. The resistivities of these layers are averaged over a given window length ($L$), using both the in-series and in-parallel configurations. If the layers are intrinsically isotropic then the upscaling can be conducted directly from a conventional resistivity log. If the layers are themselves anisotropic then the horizontal and vertical resistivities should be calculated first. The parallel averaging should be used with the horizontal resistivities and the in-series averaging with the vertical resistivities. Figure 2 shows this method of upscaling through a sediment column with thin coal layers. The layers, in this example, are assumed to be isotropic, and, therefore, the vertical and horizontal resistivities did not have to be calculated. In the depth intervals, where resistivity does not change much, anisotropy is low. In the intervals, where the coal seams are present and resistivity fluctuations are significant, the anisotropy is getting higher.

**Integrated seismic and CSEM data interpretation workflow**

Figure 3 shows an integrated seismic and CSEM feasibility workflow for anisotropic media using the methodologies described above. It is important that the electrical and
seismic work is consistent and conducted in parallel steps throughout the workflow. Inputs into the elastic and electrical models (such as mineral volume) should be the same or equivalent. The main steps of the workflow are:

Step 1: Geophysical well-log analysis (GWLA) – This is required to build an accurate and consistent well-log data set for the rock physics modelling. In this step, volumetric fractions of solid and fluid constituents are estimated.

Step 2: Estimate elastic and electrical properties at well-log scale, from well-log measurements, constitutional solid and fluid volumes and types, and rocks’ microstructural information. The inputs for this step are determined in Step 1.

Step 3: Fluid substitution is conducted for different fluid saturation scenarios. In this step, different effective rock physics models may be used for the electromagnetic and elastic parts. For instance, Gassmann fluid substitution can be used for elastic data and Archie’s Law can be used for resistivity data. This is required in order that feasibility studies can be conducted later.

Step 4: Upscaling – Well-log data are upscaled to seismic and CSEM vertical resolutions.

Step 5: Feasibility studies: The objective of a seismic feasibility study is to calculate the effect of variations in reservoir properties and physical conditions on synthetic seismograms (e.g., seismic waveform, travel times, wavefront, wavefield, AVO). This addresses a number of questions: a) to determine the changes in the calculated seismograms, b) to observe changes in the seismograms above background noise due to the perturbation of reservoir properties and conditions, and c) to assess the most realistic seismic response scenario. CSEM feasibility is achieved by calculating the synthetic amplitude responses for both the wet and hydrocarbon charged models over a range of frequencies and source-receiver offsets. The normalized difference is then calculated between the two models and assessed to determine whether the target reservoir is resolvable using the CSEM method. Synthetic gathers and NMO corrections: This is the only step where seismic modelling is conducted without a CSEM equivalent. Depending on the geologic complexity, either a ray tracing approach or full waveform elastic approach may be selected, in isotropic or anisotropic media.

Step 6: Inversion of seismic and CSEM synthetic data: Whereas it is important to demonstrate that seismic and CSEM methods are sensitive to changes in rock and fluid properties, it is also critical to assess the accuracy with which quantitative information on lithology and fluid properties can be determined from survey data. This is the goal of synthetic inversion analysis. A further goal is to develop the optimum inversion parameterization and workflow.

Step 7: Integrated interpretation of results: This is conducted to fully describe the site in both seismic and electrical terms. Jointly interpreting the results allows a more informed opinion of the type of geophysical survey that would be appropriate for this particular circumstance.
The Barnett Shale is located at depths of 1980-2590 m and is more than 305 m thick. It is also interbedded with thick limestone units, the Forestburg formation (Pollastro et al., 2007). The well logs show physical properties (e.g., velocities, density, resistivity, porosity, mineralogy, fluids) change over small intervals, which is indicative of fine heterogeneities in the subsurface formations. In this section a rock physics study for seismic characterization that targets the reservoir (e.g., the Barnett Shale formation) is shown. The workflow is designed to take anisotropy into account.

The unknown elements of the elastic tensor, at well-log scale, are estimated from the known vertical P- and S-sonic velocities and density logs in the upper and lower Barnett Shale intervals, using the rock physics model described in the section above. In the Barnett shale, we only consider the anisotropy due to horizontally oriented hydrocarbon-generated microcracks (soft-pores), with dimensions much smaller than the sonic log wavelengths (~1 m). The rock physics model estimates the soft porosity (e.g., microcracks), the soft pore density (crack density), and the aspect ratio of the soft pores (Figure 4). After upscaling, the Barnett Shale intervals show small velocity and density variations (approximately constant), and the intra-Barnett layers cannot now be discriminated (Figure 5). The Backus averaging upscaled the well log measurements to seismic scale; preserving gradational interfaces. As measures of anisotropy we use Thomsen’s parameters $\varepsilon$, $\delta$, and $\gamma$, (Thomsen, 1986). In the Barnett Shale, the P-wave and S-wave anisotropies, $\varepsilon$ and $\gamma$ at seismic scales, are less than 10%, and $\delta$ is less than 5%.

We use a well data set from the Fort Worth Basin, in Texas, USA. The stratigraphic column includes sandstones, conglomerates, shales, and carbonate formations. At log scale, all formations are assumed isotropic, except the Barnett Shale, which is assumed to exhibit vertical transverse isotropy (VTI).

---

**Figure 4** Upper interval of lower Barnett Shale. Tracks from left to right: (1) volumetric fractions of minerals, TOC, and fluids; (2) $V_p$ and $V_s$ velocities at well-log scale; (3) crack density (soft pore density); (4) aspect ratio of soft-pores, and (5) soft porosity.
We simulate common midpoint (CMP) gathers in the upscaled media, assuming first that the medium is isotropic and then anisotropic. The anisotropic gathers are computed in an upscaled model using the anisotropic BA. The isotropic gather is computed in an upscaled model using the harmonic mean of the vertical P- and S-wave elastic moduli and the arithmetic average of the density log. The traces in the computed CMP-gathers are aligned using isotropic and anisotropic normal moveout (NMO) algorithms. For the anisotropic simulations, we use the non-hyperbolic moveout in transversely isotropic media, as formulated by Alkhalifah (1997). The amplitude differences between the isotropic and

Figure 5 Tracks from left to right: (1) volumetric fractions of minerals, TOC, and fluids; (2) density log; (3) vertical sonic velocities at well-log and seismic scales; (4), (5) and (6) are Thomsen’s anisotropic parameters: \(\varepsilon\), \(\delta\), and \(\gamma\), at well-log and seismic scales. Backus (blue curve) is the Backus averaging considering all layers isotropic. SM (red curve) is Backus averaging considering the anisotropic layers (Barnett Shale intervals).

Figure 6 Left: Full waveform simulation assuming anisotropic medium (VTI). Middle: Full waveform simulation, assuming isotropic medium. Right: Difference between anisotropic and isotropic simulations.
anisotropic gathers show larger differences in the far offset data. These differences increase as offsets increase (Figure 6).

Figure 7 shows the well-log and seismic scaled properties and the computed isotropic and anisotropic CMP gathers. Only in the Barnett shale, $\varepsilon$, $\delta$, and $\gamma$ are non-zero at log scale. At the seismic scale, the amount of anisotropy varies with depth and is larger in areas with more vertical heterogeneity. The amount of P- and S-wave anisotropy, at seismic scale, is small and the effect on seismic reflections is minimal.

The simulated gathers may be used to interpret observed conditioned gathers (Singleton, 2009) in terms of rock fabric parameters (e.g., fluids, cracks, mineralogy, diagenesis, and stresses) that control the character of the seismic wavefield. The proper treatment of seismic anisotropy, allowed us to accurately place seismic reflectors (formation tops), achieve an accurate well-tie, and accurately conduct a robust AVO interpretation.

**Case study: Norwegian Sea**

Figure 8 shows an example of the electrical workflow for a Norwegian Sea well log. The sediments in this area are primarily composed of sands and shales. Reservoir sands are located at approximately 2210 m depth, are 90 m thick and are water wet. There are a few coal seams below the reservoir. Horizontal and vertical resistivities were calculated (Step 2 – workflow, Fig.3) assuming a clay background (host) in the DEM model, although the host was switched to brine in the high quartz layers (i.e., the reservoir where we assume an interconnected pore space). In the reservoir sands, fluid substitution was performed (Step 3), assuming an 80% hydrocarbon saturation. Upscaling (Step 4) was achieved using a 50 m averaging window length and resistivity anisotropy was calculated. The resistivity anisotropy ratio due to grain alignment, in general, ranges from 2–3. Anisotropy due to thin layering is low apart from in the coal seam area of the sedimentary column. The coal seams have very high resistivities, resulting in large anisotropies. The feasibility study for this well (Step 5) shows that it is a challenging case for CSEM surveying (assuming 80% saturation). Figure 9 shows the difference between the anisotropic CSEM feasibility workflow and the isotropic workflow. When an isotropic model is used, this site shows potential for CSEM surveying.
with a difference in the response between hydrocarbon and water saturated cases of 20%. When the anisotropic model is used the percentage difference plots show that the anomaly associated with the hydrocarbon-filled target is considerably lower. This is because the CSEM method in an inline geometry (considered here) is primarily sensitive to the higher vertical resistivity. The contrast between the overburden and reservoir and hence the CSEM anomaly are consequently lower than if only the isotropic, well log-derived resistivity is used. Figure 8 shows the 1D synthetic data inversion results.
(Ramananjaona et al., 2011), (Step 6), which corresponds to the final step in the CSEM feasibility study. This study shows the importance of being able to quantify anisotropy and its effects on the feasibility stage. Anisotropy at this site is at such a level that an anisotropic inversion would be required to obtain acceptable results.

Conclusions
Seismic and CSEM methods evaluate the same strata using fundamentally different techniques. Seismic surveying produces a good understanding of the geological structure of the sub-strata and indication of potential hydrocarbon sites. In contrast, CSEM provides excellent information on the fluid properties of the rock, including fluid saturation.

The advantages of the type of rock physics analysis presented here to calculate and upscale anisotropic elastic properties include:
- Proper treatment of seismic anisotropy.
- Avoiding misplacing seismic reflectors.
- Better well ties.
- Improved AVA interpretation.
- More reliable seismic inversion.

It is important to assess resistivity anisotropy when interpreting CSEM and log data to:
- Perform reliable CSEM feasibility studies,
- Build more realistic starting models for CSEM inversion and perform accurate CSEM inversion using additional information from log data.

The workflow introduced in this paper demonstrates a systematic method of analyzing elastic and electrical anisotropy. Jointly interpreting seismic and CSEM datasets leads to an improved understanding of the subsurface formations.

We have presented two case studies in which anisotropy significantly affected geophysical measurements, thereby demonstrating the importance of including anisotropy in the joint interpretation of seismic and CSEM data.

Acknowledgments
The authors would like to thank DetNorske for providing field data, WISE consortium sponsors for valuable feedback and support, and C. Ramananjaona for performing 1D CSEM inversion.

References

...