Simulation of CO\(_2\) injection into a Baltic Sea saline aquifer and seismic monitoring of the plume

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Abstract

TOUGH2/ECO2N was used to simulate CO\(_2\) injection into a saline aquifer in the Baltic Sea and the effect of different amounts of CO\(_2\) injection on the seismic response. The Biot-Gassmann model was used to convert the simulated saturation and densities to seismic velocities and synthetic seismic responses before and after injection were compared. The results show that the amplitude changes in the seismic response are detectable even for small amounts of injected CO\(_2\), while noticeable signs of velocity pushdown, as a signature of the CO\(_2\) substitution, could only be observed if the injection rate is high enough.

Keywords: Seismic monitoring; CO\(_2\) geological storage; Biot-Gassmann theory

1. Introduction

To secure the long-term safety and effectiveness of CO\(_2\) storage in a subsurface aquifer, it is important to be able to monitor the migration of the CO\(_2\) plume. For this purpose, time-lapse reflection seismic methods, among other techniques, have proven promising [1].

Application of the method is based on the fact that propagation of seismic waves in rocks depends on parameters including the porosity and elastic modulus of the rock, its lithological composition, pore fluid

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content and pressure. Substitution of water with CO₂ affects the seismic propagation characteristics in saturated layers. The changes in the properties of the rock that result from the replacement lead to changes in density, bulk modulus and seismic velocity [1]. Usually P-wave velocities are more sensitive to pore fluid content than S-wave velocities and these variations can be interpreted as a signature of plume expansion [2].

However, the changes resulting from replacement of brine by CO₂ are not always easily detectable in seismic data. Subsurface heterogeneities and the temperature and pressure of the injected CO₂ affect the quality of the seismic data. The amount of injected CO₂ and a low rate of injection can also lead to very weak responses that may not be detectable by seismic measurements. Considering the expense and difficulties of seismic data acquisition, pre-study simulations and numerical modelling are useful in assuring that the substructure response of the particular site can successfully be detected by the seismic method.

The objective of this work was to investigate the effect of the different amount of injected CO₂ on the seismic response of a specific formation in the Baltic Sea. The Baltic Sea Basin is one of the areas that have only recently received interest as a potential carbon dioxide storage area. In this work the combination of hydrogeological modelling of CO₂ injection and synthetic seismic modelling is used to answer the question whether the reflection seismic method can be used to detect the injected CO₂ plume in the modelled saline aquifer.

The ECO2N module of TOUGH2 [3] was used for numeric simulation of a system including water, salt and CO₂. Three time periods of one, three and six years of injection, using two different rates of injection, were considered in the area of the Yoldia well, located in the southeast of Sweden in the Baltic Sea. The resulting saturation data was converted to seismic velocities using Biot-Gassmann theory and both pre- and post-injection scenarios of the synthetic seismic sections were compared.

2. Methodology

The formation analysed belongs to the Cambrian sedimentary formations beneath the Baltic Sea. The formation consists of three sandy units, the so-called Viklau, När and Faludden sandstones. Decreasing with depth, the porosity of the Cambrian sandstone layers vary from 20-30% in the northern and eastern part of the basin to 5% in the central and western part of the basin [4],[5]. The formation is overlain by an Ordovician shaly carbonaceous marlstone and thick Silurian shale layer with a thickness varying between 500 and 900 meters.

2.1. Hydrogeological modelling of CO₂ injection

In this study, geological assumptions are based on data from the Yoldia well- one of the exploration wells in the region. This well is located south of Öland. The aquifer of interest is the När sandstone, which is a member of the mid-Cambrian File Haidar Formation and consists of fine and medium-grained rocks. The depth of sea water in the Yoldia well is 70 meters [6]. The layer below is assumed to be an unconsolidated layer due to its low seismic velocity and also based on the geological history of the area. The third layer consists of a thick layer of calcareous shale, siltstone and clay stone deposited during the Ordovician and Silurian, overlying a thin unit of (10 meters) Cambrian deposit. The target layer is the fifth one, which is a 35m thick sandstone layer (at the depth between 880-915m) followed by a 220 meters thick Cambrian shale (Table 1) [7].

The target layer at the Yoldia well is significantly cemented and cannot be considered as a suitable CO₂ storage. To use the model based on the formation of the layer at the Yoldia well, we used the typical petro-physical properties of the När sandstone for the target layer.
Table 1. Summary of the layer properties of the model used in this study, based on the log data from the Yoldia

<table>
<thead>
<tr>
<th>Layer</th>
<th>Lithology</th>
<th>Layer thickness (m)</th>
<th>Depth to top of layer (m)</th>
<th>Depth to base of layer (m)</th>
<th>Seismic Interval Velocity (m/s)</th>
<th>Density (g/cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>layer 1</td>
<td>Sea water</td>
<td>70</td>
<td>0</td>
<td>70</td>
<td>1430</td>
<td>1.025</td>
</tr>
<tr>
<td>layer 2</td>
<td>Sediment and poorly consolidated rock</td>
<td>65</td>
<td>70</td>
<td>135</td>
<td>1800</td>
<td>2.1</td>
</tr>
<tr>
<td>layer 3</td>
<td>Carbonaceous shales and marls and carbonates</td>
<td>735</td>
<td>135</td>
<td>870</td>
<td>3750</td>
<td>2.675</td>
</tr>
<tr>
<td>layer 4</td>
<td>Cambrian shale</td>
<td>10</td>
<td>870</td>
<td>880</td>
<td>3750</td>
<td>2.675</td>
</tr>
<tr>
<td>layer 5</td>
<td>Cambrian sandstone</td>
<td>35</td>
<td>880</td>
<td>915</td>
<td>3640</td>
<td>2.200</td>
</tr>
<tr>
<td>layer 6</td>
<td>Cambrian shale</td>
<td>220</td>
<td>915</td>
<td>1135</td>
<td>3750</td>
<td>2.675</td>
</tr>
<tr>
<td>layer 7</td>
<td>Crystalline basement</td>
<td>365</td>
<td>1135</td>
<td>1500</td>
<td>6000</td>
<td>2.75</td>
</tr>
</tbody>
</table>

To simulate the CO₂ injection, a radially-symmetric model is assumed with the injection well in the middle. The reservoir layer is a 35 meter thick sandstone aquifer at an initial pressure of 9MPa. Two different rates of injection of CO₂ were used, namely 1kg/s and 10 kg/s (0.03 and 0.3Mton per year) and injection simulation was run for 2000 days for both injection rates. The sandstone’s permeability, porosity, density and salinity were obtained from well sampling as well as the literature [4] and are summarized in Table (2). The output of the model simulations at each time is then interpreted in terms of the seismic response.

2.2. Converting saturation data to seismic velocity (Biot-Gassmann)

Biot-Gassman theory [8],[9] is one of the approaches suggested to model fluid substitution. This method relates the bulk modulus of a saturated rock ($K_{sat}$) to its porosity ($\phi$), frame bulk modulus ($K_d$), pore fluid bulk modulus ($K_f$) and matrix bulk modulus ($K_m$) by [10]:

$$K_{sat} = K_m + \frac{(1 - \phi)K_d}{\frac{\phi}{K_f} + \frac{1 - \phi}{K_m} + \frac{\phi}{K_f} - \frac{1 - \phi}{K_m}}$$

(1)

The theory is valid under several assumptions. First, the formation is considered isotropic, homogeneous and elastic with all the pore spaces connected. Second, the seismic frequency is low enough (<100Hz) so that the pore fluid can reach pressure equilibrium. Also, it is assumed that there is no interaction between pore fluids and rock minerals, meaning that the rigidity of the reservoir and, consequently, the shear modulus, remain constant [11].
Table 2. Physical properties used for the simulation

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permeability(^1) (mD)</td>
<td>280</td>
</tr>
<tr>
<td>Porosity(^1) (percent)</td>
<td>16</td>
</tr>
<tr>
<td>Salinity(^2) (g/l)</td>
<td>90</td>
</tr>
<tr>
<td>Rock compressibility(^1) (Pa(^{-1}))</td>
<td>4.7×10(^{-10})</td>
</tr>
<tr>
<td>Density of the formation (kg/m(^3)) (saturated sandstone)(^1)</td>
<td>2408</td>
</tr>
<tr>
<td>Temperature(^2) (°C)</td>
<td>35</td>
</tr>
<tr>
<td>Pressure(^1) (bar)</td>
<td>90</td>
</tr>
</tbody>
</table>

1: Based on Gardner’s equation and available well data
2: Based on literature [4] and personal communication

2.2.1. Fluid properties

Density and bulk moduli for both carbon dioxide and brine were calculated using the empirical equations of Batzle and Wang [12], which consider the conditions of salinity, temperature and pressure according to Table (2). For this calculation the relative density of gas (\(\rho_{\text{gas}}/\rho_{\text{air}}\)) was assumed as 1.54. The bulk moduli of CO\(_2\) and brine were estimated as 54.47 MPa and 2.73 GPa, respectively (Table 2).

2.2.2. Grain properties

The matrix of a media consists of several minerals that may have different bulk and shear moduli. The effective elastic modulus of the matrix depends upon the volume fraction and elastic moduli of each mineral, as well as the geometry of their connection. Since the geometry cannot be determined accurately, all the models suffer from uncertainty and their real value will fall between two (upper and lower) bounds [10]. In this study, the Hashin-Shtrikman bounds were used [11],[13].

The components of the sandstone formation were assumed to be quartz (80%) and clay minerals (20%) (OPAB unpublished report,1988). The bulk \(K_g\) and shear \(G_g\) moduli of the grain were estimated as 30.5 and 30.1 GPa, respectively.

2.2.3. Dry frame bulk modulus

To get the dry bulk modulus, equation (1) was rewritten as [11]

\[
K_d = \frac{K_{sat} - \phi K_g (1 - \phi)}{\phi K_g + K_{sat} (1 - \phi)}
\]  

The known parameters in this equation are porosity \(\phi\), fluid and grain bulk moduli and the \(K_{sat}\), value for fully saturated sandstone with water. Then it is possible to get the bulk modulus of the dry frame and this value was later used to calculate the bulk modulus of fully gas saturated media so that it could be substituted in equation (3) in order to obtain the patchy saturation bulk modulus.
2.2.4. Patchy saturation

In the case of a mixed fluid, the other important factor in determining bulk modulus is how well the fluids are mixed. In this case, if the frequency is high enough and the time scale of the propagation wave is too short for all the fluid phases to reach the pressure equilibrium, phases will remain separated and each phase will react differently to the induced pore pressure change. This condition, in which phases distribute non-uniformly, is called patchy saturation and can be formulated as

\[ K_{\text{patchy}} = \left[ \sum_{i=1}^{n} \frac{x_i}{K_i + \frac{4}{3}G} \right]^{-\frac{4}{3}G} \]  

where \( x_i \) is the volume fraction of the \( i^{th} \) patch, \( K_i \) is the bulk modulus of the rock fully saturated with the \( i^{th} \) fluid and \( G \) is the shear modulus of the rock [11],[1].

It has been shown that the upper and lower bounds of the bulk modulus and phase saturation obtained from Gassmann theory correspond to patchy and uniform saturations [1].

2.2.5. Density calculation

The density of the saturated rock can be calculated as [14]

\[ \rho = (1 - \phi) \rho_m + \phi \rho_{\text{fl}} \]  

where \( \rho_m \) and \( \rho_{\text{fl}} \) are matrix and fluid density, respectively. Knowing the gaseous (\( \rho_g \)) and liquid (\( \rho_l \)) density, alongside the gaseous (\( S_g \)), water (\( S_w \)) and salt (\( S_s \)) saturation, the density of the fluid is defined as

\[ \rho = \rho_g S_g + \rho_{\text{fl}} (S_w + S_g) \]  

3. Result and discussion

3.1. Hydrogeological modelling

Simulation of the CO\(_2\) plume expansion was carried out using the TOUGH2 modelling software. The results show occurrences of salt precipitation close to the injection well. For the largest amount of injected CO\(_2\) this solid precipitation can be observed up to 3 m from the well while for the smallest amount, the precipitation of salt is limited to less than 1 meter away from the well. Simulated gas saturation in the injection layer for two rates of injection and three injection times is shown in Figure (1).

3.2. Rock physics model

The calculated bulk moduli and material properties are summarized in Table (3). Based on these values and using equation (3) the bulk modulus of a patchy saturation model for every single grid block was calculated.
The variations in bulk and shear moduli of the formation, as a function of gas saturation, for the shallowest grid blocks are plotted in Figures (2a). These figures compare patchy and uniform saturation models for the largest amount of injected CO2. Equation (3) implies that, for a fully saturated formation, patchy and uniform saturation models will be equal. The unexpected pattern at the highest saturation rate in Figure (2a) can be explained by salt precipitation next to the injection well; salt precipitation can affect the porosity and permeability as well as bulk modulus [3]. This interpretation can be verified in Figure (2b), which shows the estimated bulk modulus of the formation when the effect of the solid saturation is removed.

Table 3 Material properties of the aquifer

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grain bulk modulus(^1)</td>
<td>30.507 GPa</td>
</tr>
<tr>
<td>Dry bulk modulus(^2)</td>
<td>13.321 GPa</td>
</tr>
<tr>
<td>Brine density(^3)</td>
<td>1053 Kg/m^3</td>
</tr>
<tr>
<td>Brine bulk modulus(^3)</td>
<td>2.735 GPa</td>
</tr>
<tr>
<td>CO2 density(^3)</td>
<td>501.9 Kg/m^3</td>
</tr>
<tr>
<td>CO2 bulk modulus(^3)</td>
<td>0.125 GPa</td>
</tr>
<tr>
<td>Bulk modulus of water saturated media(^4)</td>
<td>17.746 GPa</td>
</tr>
<tr>
<td>Bulk modulus of gas saturated media(^4)</td>
<td>13.567 GPa</td>
</tr>
</tbody>
</table>

1- Based on Hashin-Shtrikman bounds  
2- Based on equation (2)  
3- Based on (Bazle and Wang model, www.crewes.org/ResearchLinks/ExplorerPrograms/FlProp/FluidProp.htm)  
4- Based on equation (1)
Figure 2. Calculated bulk and shear moduli with respect to gas saturation (a) considering salt precipitation, (b) calculated bulk and shear moduli with respect to gas saturation ignoring salt precipitation. (c) P-wave velocity decreases with respect to gas saturation in the patchy and uniform saturation models, (d) S-wave velocity increases with respect to gas saturation (for the higher amount of injected CO₂).

Figure (2c) shows the calculated P-wave velocities based on the patchy saturation model. It is clear that the maximum drop in P-wave velocities can be observed next to the injection well where the CO₂ saturation is also maximum. As the gas saturation increases the P-wave seismic velocity decreases and the S-wave velocity slightly increases (Figure 2d).

The results for the highest injection rate show a decrease in P-wave velocity by 4.7% while shear wave velocity increases by 1.26%. For the smallest amount of injected CO₂, the P-wave velocity decrease is 4.65% and the S-wave velocity increases by 1.41%. It is also clear from Figure (2a) that bulk modulus values (as a function of gas saturation in the patchy saturation model) show a more gradual decrease in comparison to the uniform saturation model resulting in a more gradual decrease of the P-wave velocity as a function of saturation in Figure 2c.

The range of velocity changes is somewhat lower in comparison with other similar studies; Xue and Lei (2006)[15] reported a 10% decrease in P-wave velocities for laboratory measurements on several sandstone samples. They showed that the P-wave velocity reduction primarily depends on dry bulk modulus; softer rock would show a larger reduction while stiffer rocks (higher $K_d$) have a smaller sensitivity to fluid substitution. Vera (2012)[16] investigated the CO₂ effect on seismic velocity changes...
on a sandstone aquifer near Calgary, Canada and reported a 6-7% reduction in P-wave velocity and a 0.64% increase in shear wave velocities, which is comparable to this study.

For the Ketzin site in Germany, the bulk modulus reduction has been stated as around 41% [11] much higher than the 20.6% result found in this study. In the Ketzin case, the porosity of 20%, shallower depth of the aquifer (650 m) and higher range of salinity (230 gr/lit) might explain the difference. Again, the estimated dry bulk modulus for the Ketzin site is less than in this study.

### 3.3. Synthetic Seismic modelling

The seismic velocity model, based on a simple 1D model obtained from the Yoldia well data is shown in Figure (3). The figure compares the seismic velocities of the baseline, i.e. before injection, and after 2000 days of injection, at the injection rate of 10 kg/s. The injection layer can be seen at a depth of about 880-915 meters.

The effect of fluid substitution on seismic measurements can be addressed by regarding either the changes in signal amplitudes, or the time delay due to the corresponding injection layer (velocity pushdown). To qualitatively investigate the seismic response as a result of variation in gas saturation, the stacked sections of each injection scenario were subtracted from the stacked section of the baseline. The results are shown in Figure (4).

![Figure 3. Velocity model (a) before and (b) after injection (2000 days after injection with an injection rate of 10 kg/s)](image-url)
Figure 4. Subtraction of the repeat from the baseline for the lower injection rate: (a) 365 days, (b) 1000 days and (c) 2000 days, and for the higher injection rate: (d) 365 days, (e) 1000 days and (f) 2000 days after injection. Vertical axis is time (s) and horizontal axis is distance (m). The red colours show positive and blue colours show negative amplitudes.

The figure shows the effect of the different amount of injected CO$_2$ on the seismic response. The change is obviously less for the smaller amount of CO$_2$ in the aquifer. (the smallest and the highest amount of injected CO$_2$ correspond to 0.03Mton and 1.7Mton respectively). The effect of the time delay can also be observed on the lower layer. It means that the velocity reduction in the injection layer above leads to an increase in the travel time of the seismic wave recorded from the lowers below.

It should be mentioned that simplifying assumptions including ignoring possible coherent or random noise, 3D effects, as well as heterogeneity and anisotropy can lead to overestimating the accuracy of the method.

4. Conclusion

The TOUGH2 simulations, two different rates of injection resulting in different amounts of injected CO$_2$, show the dominant effect of buoyancy upon the expansion of injected CO$_2$. It was found that Biot-Gassmann theory is a practical tool to model fluid substitution and can be used to link hydrological and geophysical approaches in subsurface investigations. The decrease in P-wave velocities, as a result of CO$_2$ injection, showed that a 2D seismic survey could be successfully used in monitoring the carbon dioxide plume expansion of the injected amounts at the depth of interest of the test site under consideration. This conclusion is valid for this synthetic test only as it includes several assumptions, including the assumptions of a homogeneous, isotropic formation with connected pores, as well as ignoring seismic noise and 3D effects. The amplitude change resulting from gas saturation was visible in the seismic response for both the lower and higher injection rates, while the velocity pushdown was clearer in the subtraction sections of higher amounts of CO$_2$ from the baseline (before injection scenario). The effect of gas saturation on P-wave velocity reduction, in the case of the higher injection rate, was also observable on seismic records from the deeper layers.
The estimated P-wave velocity decrease for this particular site was found to be lower in comparison with other studies. This variation can be explained by the different geological and petro-physical properties of the different sites, meaning different stiffness’s as well as different injection rates and saturation model effects.

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References