Theoretical detectability of CO₂ at a CCS project in Alberta

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Summary

A time-lapse analysis was carried out to investigate the theoretical detectability of CO₂ for the Shell Quest project. Quest is a Carbon Capture and Storage (CCS) project in Alberta operated by Shell Canada Energy and its partners. The target formation for injection is the Basal Cambrian Sandstone (BCS) which is a deep saline aquifer at an approximate depth of 2000 meters below surface in the Quest project area. The purpose of this study was to simulate the seismic response of the BCS after injecting 1.2 million tonnes of CO₂ during a one-year period of injection. This was done using Gassmann fluid substitution and seismic forward modeling. A geological model for the baseline scenario was generated based on logs from well SCL-8-19-59-20W4. For the monitor case, Gassmann fluid substitution modeling was undertaken to model a CO₂ plume within BCS. Numerical stack sections for both scenarios were obtained and subtracted to study the change in the seismic response after injecting CO₂. The difference section shows the location and the spatial distribution of the plume. Based on these results the CO₂ plume could be detected in the seismic data after a year of injection, providing the data have good bandwidth and a high signal-to-noise ratio.

Introduction

Carbon Capture and Storage (CCS) is one of the methods for reducing the emissions of CO₂ in the atmosphere. In this process, the produced CO₂ from large emitters is captured before it is released into the atmosphere. It is transported and then injected into a deep geological formation for permanent storage. Quest Carbon Capture and Storage is a joint CCS project among Shell Canada Energy, Chevron Canada Limited and Marathon Oil Canada Corporation. The purpose of this project is to reduce the CO₂ emission from Scotford Upgrader by storing it in a deep geological formation. The location of the Scotford Upgrader is about 5 km northeast of Fort Saskatchewan, Alberta, within an industrial zone (Shell, 2010). The selected geological formation for the CO₂ storage is the Basal Cambrian Sands or BCS, which is a saline aquifer within Western Canadian Sedimentary Basin (WCSB), with an approximate depth of 2000 meters below the surface in the Quest project area. BCS is ideal for carbon storage since it is overlain by several seals (Bachu and Stewart, 2002). The primary seal is Middle Cambrian Shale (MCS) which is a marine shale with a maximum thickness of 60 meters. The Lower Lotsberg Salt that is 100% halite with a maximum thickness of 60 meters is the secondary seal, and the ultimate seal is Upper Lotsberg Salt with a maximum thickness of 150 meters (Shell, 2010). The porosity of BCS is between 8 to 24 percent and its permeability between 1mD to 1D. These properties represent a good reservoir quality for BCS that is favorable for capturing CO₂ (Shell, 2010).

Figure 1 shows the logs from well SCL-8-19-59-20W4 that was used in this study. Only density and P-wave velocity are shown in this figure along with major formation tops. BCS thickness, measured from the well was 49 meters, and the porosity calculated from the density log was 16% which is a very suitable porosity for CO₂ sequestration.

The goal of this study was to investigate the theoretical detectability of CO₂ for Quest project. For this purpose Gassmann fluid substitution (Gassmann, 1951) was undertaken to calculate the properties of BCS after injecting CO₂. When the in-situ pore fluid is substituted...
with a new fluid, physical rock properties such as density and seismic wave velocities change (Gassmann, 1951; Smith et al., 2003). These changes will lead to changes in the amplitudes and travel times of the seismic data. In this study the monitor and baseline seismic sections were simulated to investigate the detectability of CO₂ in the Quest project.

Method

A geological model was generated based on the well logs mentioned previously. This model was used for the baseline numerical seismic survey (Figure 2a). For more accuracy, BCS was divided into 7 thin layers with an average thickness of 7 meters for each layer. The detailed view of BCS and its physical properties are shown in Figure 3. The model was then modified to simulate the monitor survey by adding a CO₂ plume to BCS. The properties of the plume were calculated using Gassmann fluid substitution for BCS. This approach is suitable for clean sandstone reservoirs. Figure 4 illustrates the changes in P-wave velocity versus CO₂ saturation for all 7 layers within BCS. The maximum time lapse effect occurs at 40% CO₂ saturation and the velocity does not change considerably for higher saturation values. Therefore, it was assumed that the plume had 40% CO₂ saturation in the monitor model.

The size of the plume was estimated based on the injected amount of 1.2 million tones of CO₂ after one year injection and also the porosity of BCS. This plume had a semiconical shape (with a radius of 800 meters) to better describe the CO₂ distribution affected by the buoyancy force. Figures 2b and 2c show the Monitor model and a close view of the plume, respectively.

![Figure 2: The P-wave velocity model for baseline (a) and monitor (b) scenarios, and a closer view of the CO₂ plume in BCS(c).](image-url)

![Figure 3: A detailed view of BCS in the model, where it is divided to seven thin layers. BCS is overlain by Lower Marine Sands or LMS and underlain by Pre-Cambrian.](image-url)
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The 2D survey designed for this study was composed of 101 shots with 500 live receivers for each shot, with a symmetrical split spread layout. The receiver and shot spacing were respectively 10 and 100 meters. Therefore, the survey covered a line with the total length of 10000 meters with a maximum fold of 25 at the centre. For generating the shot gathers the model was extended to 10000 meters where for the monitor model the CO₂ plume was added to BCS at the centre of the line. The synthetic shot gathers for both baseline and monitor scenarios were generated using NORSAR2D which is seismic ray-tracing modeling software package. Ray-tracing in NORSAR2D is based on shooting method where a fan of rays is sent out from the source to find the ray that hits the receiver. The wavelet used for generating the shot gathers was a zero phase Ricker wavelet with the dominant frequency of 50 Hz. Figures 5 and 6 show shot gather number 1500 for the baseline and monitor surveys respectively.

The generated shot gathers were then processed in the VISTA seismic processing package. Since this was a synthetic data without topography, no static correction was needed. In addition the velocity model was known already, so the data were ready for NMO correction. After NMO correction CMP stack sections were generated for both monitor and baseline surveys (Figure 7). To see the changes due to CO₂ injection, the baseline section was subtracted from the monitor section to obtain the difference section. Figure 8 illustrates the difference of the two sections. It is clear that the CO₂ injection has caused changes in the amplitude and travel times relative to the baseline survey, which leads to residual events in the difference section.

Results

The results showed that the injection of CO₂ leads to a change in amplitude and travel times within and underneath the plume which causes a difference in the monitor seismic response. In order to measure these changes, the traces at CMP location 1499 were extracted from the baseline and monitor sections. Figure 9 shows these traces overlain on each other. The reflection from the top of Pre-Cambrian (approximately at 1.2 s) showed a time shift of 0.003 s after injecting CO₂. Also the RMS amplitude between the times 1.15 s and 1.21 s increased about 30 percent in the monitor section.

The horizontal distribution and also the top of the plume were clearly observable in the difference section. However, the shape of the plume did not appear in a semi-conical shape since there were time shifts in the reflectors underneath the plume ends, and the plume thickness everywhere is less than the resolvable thickness given the bandwidth of the seismic data.

Conclusions

Gassman’s equation is a useful method for modeling the changes in the rock properties of the storage formation after injecting CO₂.
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The changes in rock properties of the BCS after one-year period of injection are large enough to be detected in the seismic sections, providing the data have a high signal-to-noise ratio. These changes appear as change in amplitude and traveltimes in the monitor section and could be better observed when the baseline section is subtracted from the monitor section. The shape of the plume could not be precisely determined; however, the spatial distribution and the top of the plume could be observed in the difference section. The effect of signal to noise ratio on the detectability of CO$_2$ can be investigated in ongoing research.

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