Reservoir simulation and feasibility study for seismic monitoring at CaMI.FRS, Newell County, Alberta

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Summary

We present the results of reservoir simulations and feasibility study of surface seismic monitoring applied to the CO_2 sequestration at the CaMI Field Research Station (FRS). We first test the influence of injection parameters, as reservoir temperature, maximum bottom-hole pressure and of the ratio vertical permeability over horizontal permeability on the amount of CO_2 you can inject and on the gas plume shape. We demonstrate that if the reservoir temperature has a very small influence on the injectivity, the maximum bottom-hole pressure and the ratio of permeabilities play a key role on the gas injection.

The next step is fluid substitution, necessitated to estimate the variation in elastic parameters induced by the gas injection. We test different methods to compute the bulk modulus of the fluid (Reuss, Voigt, HRV and Brie) and compare their results. We finally use a 3D finite difference modeling to simulate the seismic response in the elastic models generated for the baseline, for 1 year of injection and for 5 years of injection.

Introduction

The Containment and Monitoring Institute (CaMI) of CMC Research Institutes Inc. (CMC), in collaboration with the University of Calgary, has developed a comprehensive Field Research Station (FRS) in southern Alberta, Canada. The purpose of CaMI.FRS is to develop innovative technologies to prevent and monitor early leakages of a deeper, large-scale CO_2 reservoir. To simulate a leakage, a small amount of CO_2 (< 600 t/year over 5 years) will be injected a shallow surface (300 m depth).

The target of injection is the Basal Belly River Sandstones (BBRS), a 7m layer thickness (from 295 to 302m depth), composed of fine to medium-grained of poorly to well sorted lithic grains. The seal is the Foremost Formation which is a layer 152 m thick composed of clayey sandstone with more or less continuous, intercalated coal layers

To detect and monitor the injected CO_2, different geochemical and geophysical instruments are in place on the field (Lawton et al., 2015a). So far, these have been used to characterize the subsurface and will be used as baseline for the monitoring studies. A non-exhaustive list of geophysical instruments on CaMI.FRS includes a Digital Acoustic Sensing (DAS) permanently installed, VSP experiments with downhole geophones, surface seismic survey, and a permanent a10x10 array of buried 3C geophones (10m spacing, buried at 1m depth) with soon installed permanent sources.

We explain in this paper the four steps leading to the feasibility study of seismic monitoring applied to CO_2 sequestration: 1) geomodelling; 2) injection simulations; 2) fluid substitution; and 4) simulation of seismic responses.

Geostatic Model

Porosity and permeability are two key variables required for reservoir characterization and dynamic fluid-flow simulation. We use the logs of 88 wells available in the area and two seismic volumes and build 3D layer cake laterally homogeneous models of horizontal permeability and porosity.

Figure 1 shows the porosity and permeability 1D profiles as well as the lithology of the subsurface. Average permeability in the BBRS is 0.8mD and average porosity is 10%.

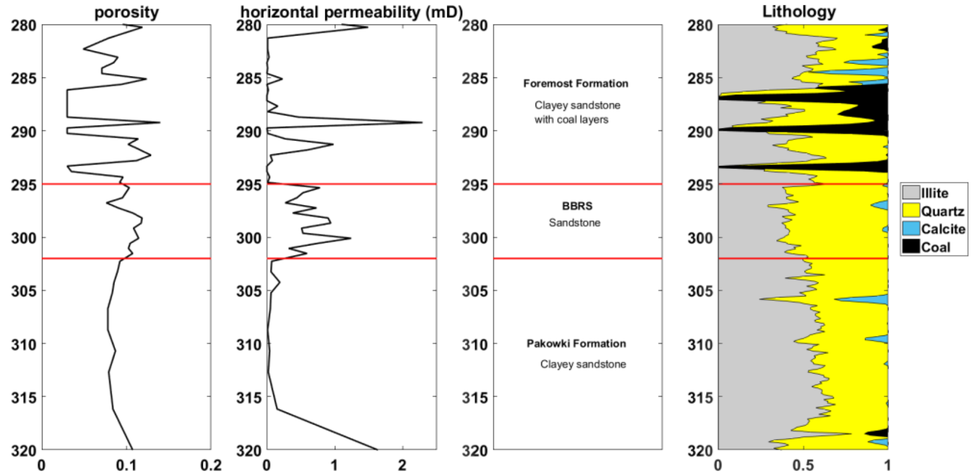

Figure 1. Zoom of the area of interest of the layer cake model without lateral variation. The porosity and the permeability are extracted from the 3D geostatic models. The lithology is extracted from the ELAN logs (Swager, 2015). Red lines are the limits of the BBRS which is the layer of injection.

Injection simulations

We use CMG-GEM, a fluid flow simulator software and test the influence of different parameters of injection. The minimum water saturation (0.5) remains the same during the different tests as well as the relative permeability of gaseous CO_2 and water (calculated using Brooks-Corey approximation). We also assumed an initial saturation of brine of 100% in the medium.

Figure 2 shows the results of the test on the ratio of permeabilities. We can see that the amount of CO_2 injected increases with the increase of the ratio. A higher vertical permeability allows the gas to migrate vertically more easily. With the vertical migration, the pressure decreases in the medium and so the injectivity can be higher. However, if we can observe a downward migration, no upward migration is allowed due to the quasi-null permeability at the very bottom of the Foremost formation (Figure 1).

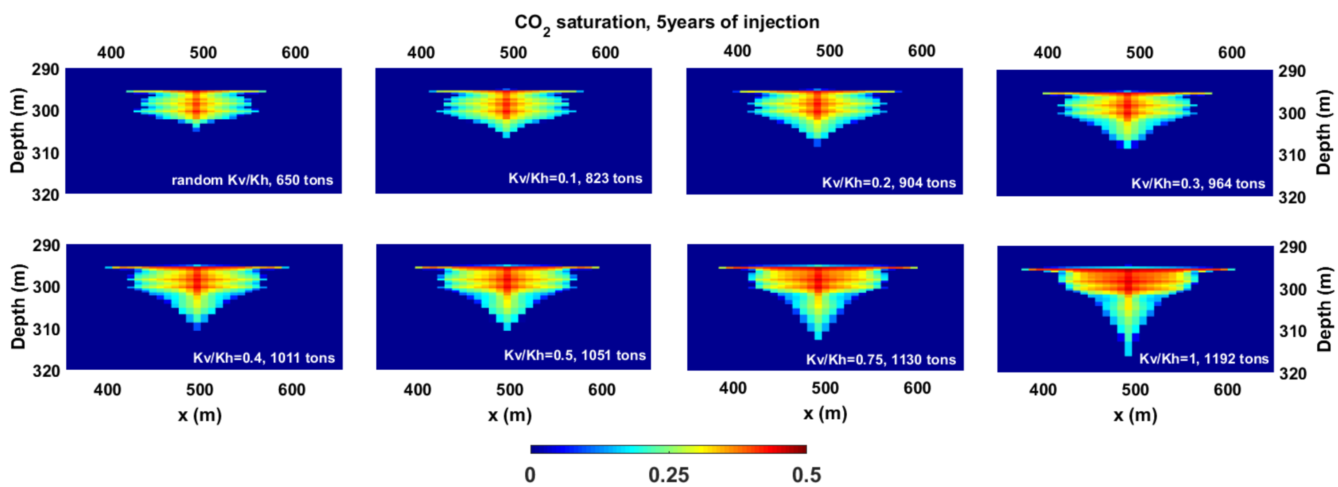

Figure 2. Effect of the ratio vertical permeability over horizontal permeability. 5 years of injection.

Figure 3 shows the CO_2 saturation after 5 years of injection for different maximum bottom-hole pressure and reservoir temperature (going from [BHP=4.5MPa, T=10°C] to [BHP=5.75MPam T=20°C]). More detailed test shows that if the reservoir temperature has very weak influence on the injectivity, the maximum bottom-hole pressure mostly drives the amount of gas injected. Instinctively, the higher is the maximum bottom-hole pressure, the higher is the injectivity.

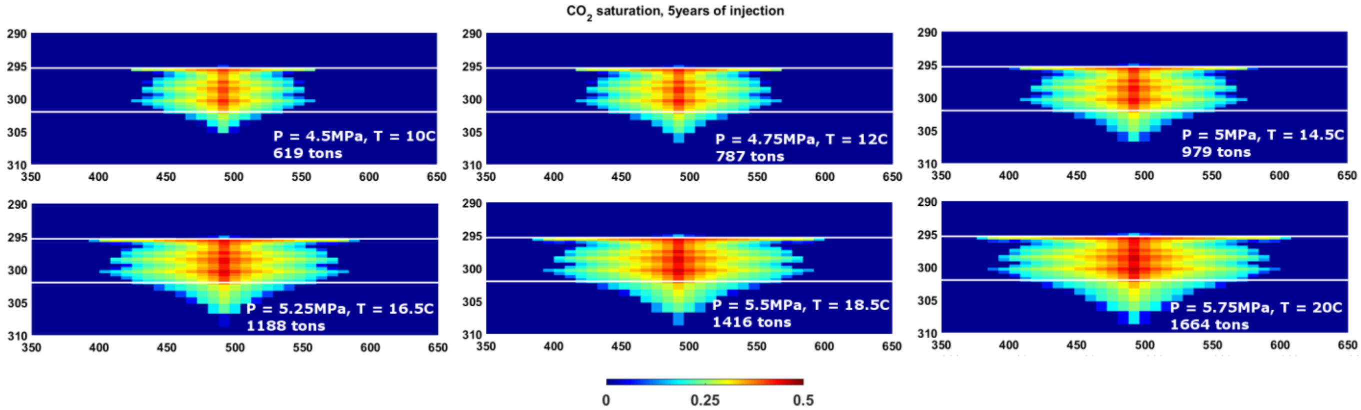

Figure 3. Effect of the reservoir temperature and the maximum bottom-hole pressure. 5 years of injection.

Fluid substitution

We use Gassmann's equation (Gassmann, 1951) to compute the new saturated bulk modulus needed to compute the new elastic parameters due to gas injection (Macquet et al. 2017). The main uncertainty of this method is the way to compute the fluid bulk modulus which depends on how the components of the fluid mix together. We test the different methods described in the literature: the Reuss, Voigt, HRV and Brie equations describing respectively an uniform saturation, a patchy saturation and two semi-patchy saturations. Figure 4 shows the P-wave velocity variations expected after 5 years of injection for the four methods. We can see that using a patchy saturation gives less variation than an uniform saturation (-4% and -22% respectively) as the fluid bulk modulus is higher in the first case (Figure 4.a).

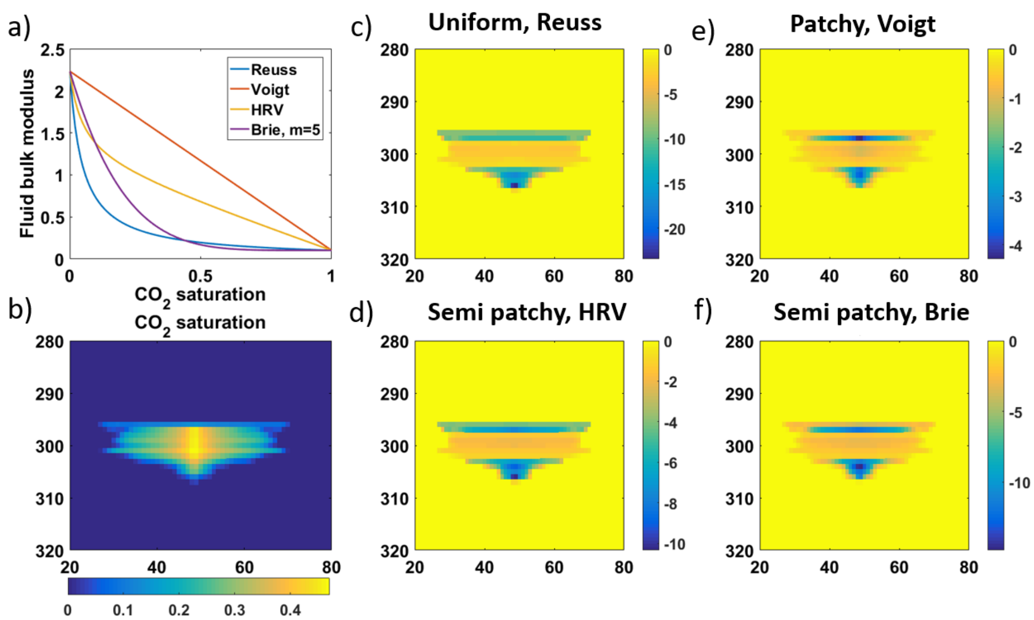

Figure 4. Test of the different methods to compute the fluid bulk modulus. a) Fluid bulk modulus as a function of CO_2 saturation. b) CO_2 saturation after 5 years of injection. c) Variation of P-wave velocities using Reuss method. d) Variation of P-wave velocities using HRV method. e) Variation of P-wave velocities using Voigt method. f) Variation of P-wave velocities using Brie method.

Simulation of seismic responses

Seismic data were simulated using TIGER, a 3D finite-difference modelling software (from SINTEF Petroleum Research). We use the inner part of the actual survey acquired in 2014 on the field

(Lawton et al., 2015b). It contains a total of 561 receivers and 561 sources (source and receiver spacing of 10m, source and receiver lines interval of 50m), for a final bin size of 5mx5m.

Figure 5 shows 2D vertical and horizontal sections of the difference between the time lapse periods and the baseline, after standard processing applied on synthetic data (deconvolution, NMO, CMP stack and post-stack migration). To be closer to real data, we add a noise corresponding to a SNR of 20 to the synthetic data. This level of noise was estimated on the data acquired on the field (Isaac and Lawton 2015). The black lines added in figure 5 show the lateral expansion of the gas plume. We can see that either for 1 year of injection (266 tons of CO_2) or 5 years of injection (1330 tons of CO_2), the reflectivity anomalies correspond to the location of the gas plume. Note that those results assumed a uniform saturation, but results may differ if we use a different saturation behavior.

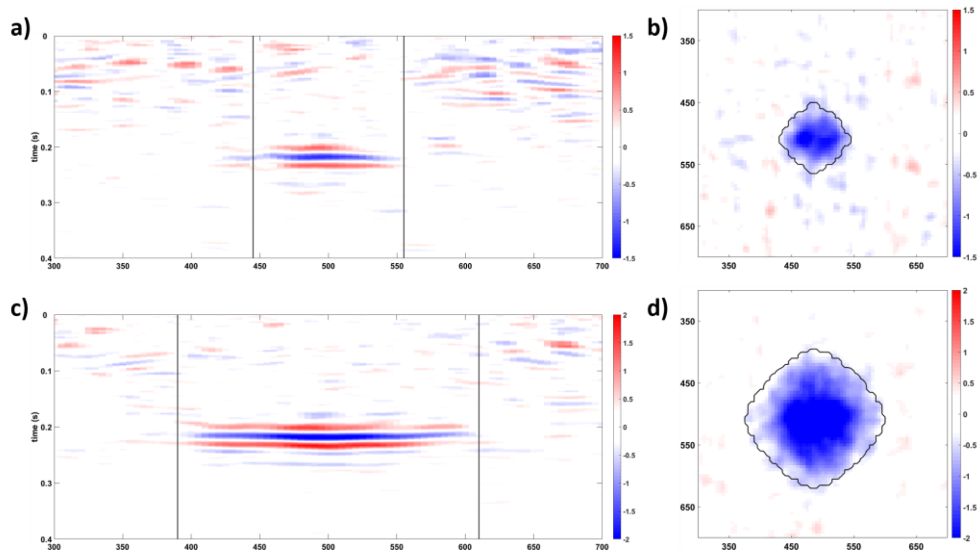

Figure 5. Results of the difference between the simulated time lapse periods and the baseline seismic volumes, adding noise corresponding to a signal over noise ration of 20. a) Vertical section along the injector well, for 1 year of injection. b) Horizontal section at the top of the reservoir, for 1 year of injection. c) Vertical section along the injector well, for 5 years of injection. d) Horizontal section at the top of the reservoir, for 5 years of injection. Black lines show the lateral expansion of the CO_2 plume

Conclusions

We explore the different parametres assumed during a feasability study for seismic monitoring, applied to a small amount of CO_2 injected at shallow surface at the CaMI.FRS. We test different bottom-hole pressure and different ratios of permeabilities and show their effect on the amount of injected CO_2. Instinctively, the higer those parameters are and the higher is the injectivity.

During the fluid substitution step, the main assumption is on the saturation behavior. In the absence of laboratory tests, we test the different methods to compute the elastic parameters variations.

Finaly, we demonstrate that despite of the small amount of CO_2 (266 tons of gas after 1 year), surface seismic monitoring is able to detect the trace of the gas plume.

Acknowledgements

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