Multi-Physics Simulation of CO_2 Storage in The Leduc Deep Saline Aquifer

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Summary

The Leduc Formation is comprised of dolomitized Upper Devonian carbonate reefs and reef complexes in the west-central and southern Alberta Basin. While historically targeted for oil production, regions of the reservoir complex are occupied by brine, acting as a massive deep saline aquifer. Geologic sequestration of CO_2 in deep saline aquifers is a promising strategy for the permanent and secure storage of CO_2.

This preliminary study aims to assess the feasibility of injecting supercritical CO_2 at scale into the Leduc aquifer in northwest Alberta through coupled hydro-thermo-chemo-mechanical simulation.

Model input parameters (e.g., petrophysical, geomechanical, and fluid properties) are based on real data from the target aquifer. The compositional flow simulation model includes a multi-layer overburden that extends to surface. CO_2 is injected through a multi-well hub in the Leduc aquifer. The pore pressure variation and mechanical response of the aquifer after 40 years of injection and 200 years of shut-in are simulated using a fully coupled multi-million cell earth model. The impact of proximal high-volume Leduc saltwater disposal wells is accounted for in the flow simulations.

The simulation results highlight the opportunity and potential challenges for injecting CO_2 in the Leduc aquifer by assessing the fully coupled geomechanical response of the model.

Theory / Method / Workflow

In the fully-coupled geomechanical simulation approach, the joint coupled system of equations describing the diffusion processes in a reservoir and the geomechanical effects are solved simultaneously using finite volume and finite element methods. The simulation equations account for the impact of equilibrium geochemical reactions, compositional variations, salt precipitation, rock mechanics, and thermal effects (Rock Flow Dynamics 2025).

In this study, the simulation model covers a large area of the Leduc Formation, around 50 km x 60 km. The model is comprised of around 5.5M cells with local grid refinement around the wells, representing the Leduc aquifer, Ireton caprock, underburden and a set of overburden layers extending to the surface.

The aquifer has an average thickness of around 300 m with an initial pressure and temperature of 420 bars and 114°C, respectively, at 4000m TVD. The model input parameters, including geomechanical properties (Enhance Energy 2012), petrophysical data (Rock 1999), hysteresis relative permeability curves (Bennion and Bachu 2008), and capillary pressure (Geng et al. 2024) are based on measured data from different wells in the Leduc Formation. Relevant correlations are also used to estimate other input parameters such as diffusion coefficients (Sigmund 1976b, 1976a, Yoshida et al. 2009, Lu et al. 2013).

The CO_2 injection hub includes 7 vertical wells that are completed in the lower 200m of the aquifer. There are 5 major water injection disposal wells and an equivalent net brine producer well near the injection hub. All of the CO_2 injection wells inject cooler CO_2 at 25°C with a constant surface injection rate of 0.33M ton/y for 40 years and 200 years of shut-in time. A detailed wellbore model is constructed to account for the CO_2 phase change in the wellbore and extract the vertical lift performance to convert the surface pressure to bottomhole pressure effectively.

The geomechanical stress regime at this depth is likely strike-slip. The stress boundary and initial conditions are set up using the measured data from wells in the same field (Enhance Energy 2012). The coupled geomechanical simulations are conducted using multi-core CPU and an RTX 4000 ada® generation GPU on a high-performance computer.

Results, Observations, Conclusions

Fig. 1 demonstrates that after 40 years of injection, approximately 60% of the total injected CO_2 is still in the mobile phase, whereas the dissolved and trapped CO_2 contributions are around 25% and 15%, respectively. However, after 200 years of shut-in time, a considerable portion of the mobile CO_2 (23%) will be consequently trapped or dissolved in the in-situ brine.

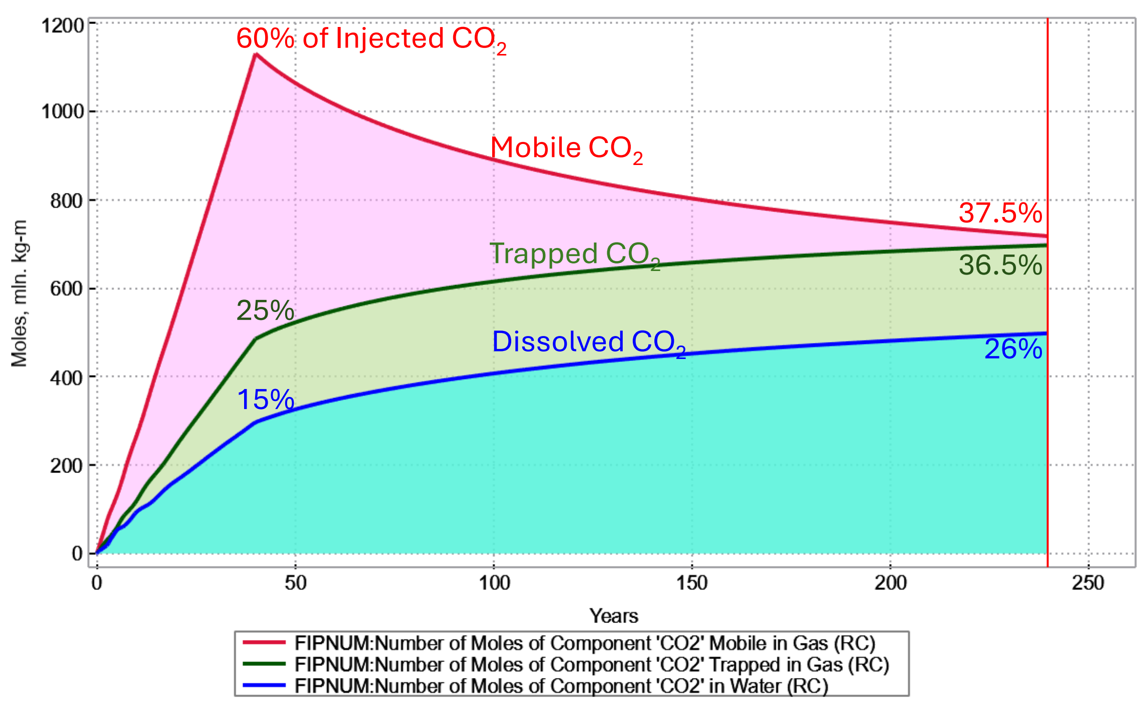

Fig. 1 — Simulation results indicating the number of moles of CO_2 in the mobile, trapped, and dissolved states.

The simulation results reveal that after 40 years of injection, the field pressure can increase by 60 bars in areas close to the injector (Fig. 2; left). This additional pressure increase can lead to a poro-elastic response with a surface uplift of around 6 cm (Fig. 2; right). Further, the simulations demonstrate that halite precipitation does not pose a significant risk to the long-term storativity of CO_2. However, as indicated by the simulation results, after the injection period, the pH of the brine-CO_2 solution near the injectors has significantly dropped by almost 50%, which has implications for rock-water reactions and wellbore corrosion.

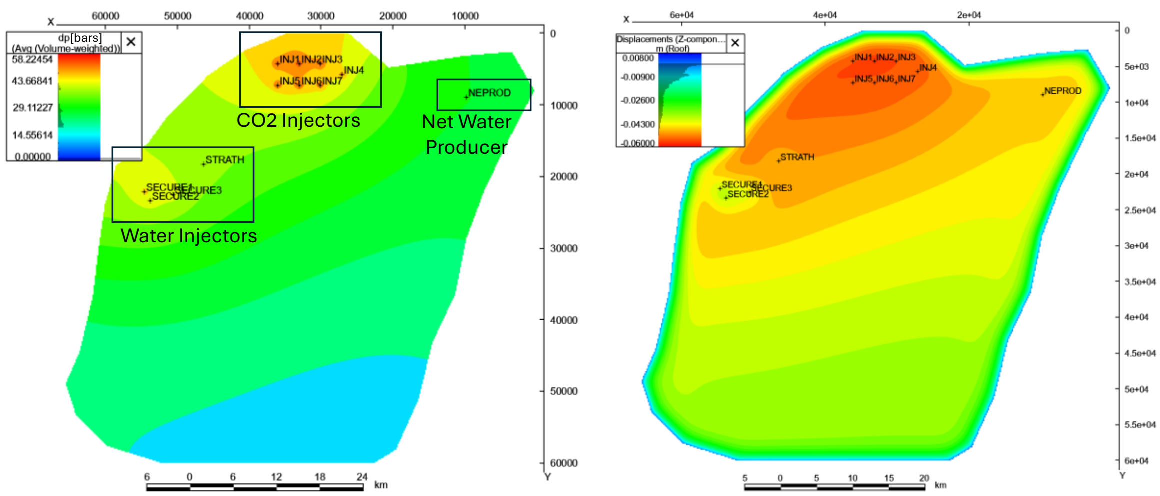

Fig. 2 — Surface uplift (left) and the volume-weighted pressure drop map in the Leduc formation after 40 years of injection and production.

Additionally, the simulation results suggest that, with low-temperature CO_2 injection, there is a chance of induced thermal fracturing due to the reduction of effective stress near the wellbore, potentially surpassing the tensile strength of the rock. Additional simulations with warmer temperatures were also conducted.

Initial simulations included an injection CO_2 hub with 7 injectors. However, due to the high cost of injecting CO_2 at such a depth, different well counts and injection rates were also simulated. However, it was noted that when the injection rate is ramped up per well, there is a higher risk associated with rock failure due to a higher increase in bottomhole pressure (Song et al. 2023).

It should be noted that although a substantial effort is made to obtain relevant and accurate data for conducting simulations, there is still significant uncertainty in the lateral model structure and utilized input parameters. The impact of uncertainty on the simulation results will be investigated in a future study.

Novel/Additive Information

This study provides a systematic workflow to assess the feasibility of the geologic sequestration of CO_2 in the Leduc saline aquifer. The results highlight the challenge and opportunities of securely storing large amounts of CO_2 underground. More importantly, the results can help the operating company better design the storage hub to mitigate short- and long-term operational risks.

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