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Assessing CO_2 injection capacity and safe CO_2 injection rates in the fractured aquifer of the Potsdam sandstone, Quebec

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Summary

CO_2 storage operations in fractured sandstone reservoirs are challenging as they may result in high reservoir pressure buildup, caprock hydraulic fracturing, or shear slip reactivation of optimally oriented faults (March et al., 2018; Konstantinovskaya et al., 2020; Bondarenko et al., 2021; Bowersox et al., 2021). In this study, we assess CO_2 injection capacity in the deep saline aquifer of the Lower Paleozoic Potsdam sandstone of the Bécancour area, Quebec, at a depth of ~1.2 km. The sandstone reservoir has a low total porosity of 2-13% and permeability of 0.13-4.3 mD. The Discrete Fracture Network (DFN) modeling based on the FMI log analysis is used to simulate the presence of natural fractures in the reservoir. The safe CO_2 injection rates and reservoir pressure buildup are estimated using 3D reservoir simulations of CO_2 injection in vertical and horizontal wells. The reservoir pressure buildup is analyzed to evaluate the risk of top seal failure and fault/fracture reactivation associated with the CO_2 injection. The results of CO_2 injection simulations in the fractured reservoir are validated by the history match analysis of brine production from the Potsdam sandstone in a vertical well.

Data and Methods

The study area of 2.6 km x 5.4 km is located in the area of Bécancour town, in the footwall of the Yamaska Fault (Fig. 1). We use petrophysical properties (porosity and permeability) of the Potsdam sandstone based on well logs and core petrophysical testing data in 3 vertical wells A196, A198 and A246 (Fig. 1a, Table 1) that penetrate the sandstone of the Potsdam Group (Cairnside and Covey Hill Formations) in the area (Tran Ngoc et al., 2014; Konstantinovskaya et al., 2023). The porosity and permeability properties in the Potsdam sandstone were upscaled from logs in wells A196 and A198 and propagated in the model using kriging method (Figs 1b, 2).

Discrete Fracture Network (DFN) modeling is completed in Petrel using available FMI well data in the Bécancour area (Konstantinovskaya et al., 2023, 2024). DFN modeling was performed with two fracture sets oriented Dip Azimuth N123°/80° and N214°/80°, simplified from the results of FMI log analysis. Maximum length of fractures was set 100 m. Fracture aperture was modeled with log-normal distribution, mean value 0.56 mm, max 5 mm. Fracture porosity was upscaled into the 3D model from DFN fracture systems, and fracture permeability was modeled using the Oda geostatisctical method based on geometry and distribution of fractures in each cell; no transmissivity multiplier was introduced.

3D reservoir simulations of CO_2 injection in the saline aquifers of the Potsdam sandstone are conducted for 20 years from January 2023 to January 2043 in Eclipse300™ using the CO2STORE module (Spycher and Pruess, 2005) for the dual porosity and dual permeability settings to take into account the fluid flow through natural fractures.

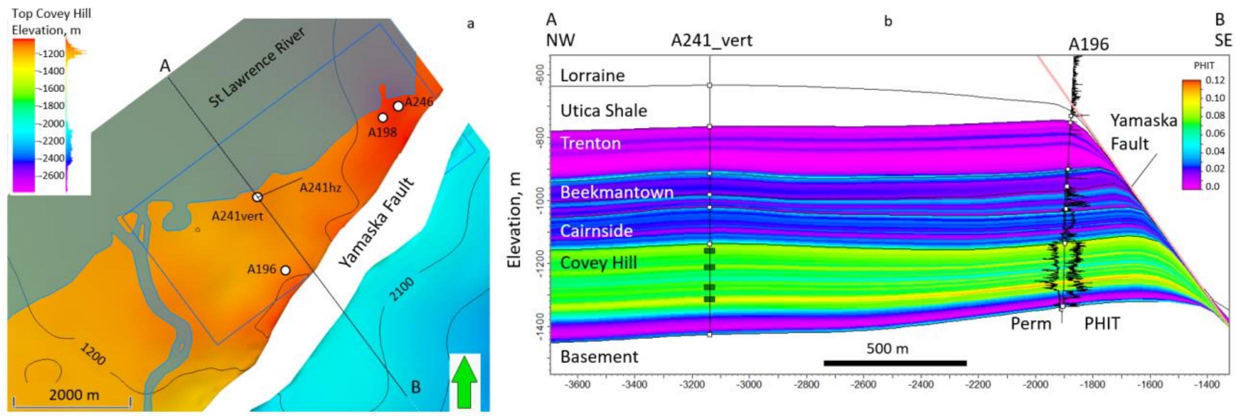

Fig. 1 (a) Map of the top of the Covey Hill Formation in the Bécancour area; location of selected drilled wells and simulation wells is shown; (b) NW-SE structural cross-section A-B of the footwall of the Yamaska Fault displays total porosity (PHIT) property. Density porosity (PHIT) and permeability (Perm) well logs are shown for projected A196 well. The trajectory and completion of the simulation well A241vert are shown.

Table 1. Drilled and simulation wells in the Bécancour area that were used in this study. See Figs 1 and 2 for the location and trajectory of the wells.

Well #	Well name	Geographic NAD83		UTM NAD83 zone 18N		KB, m	Total depth, m	Ground elevation, m
		Lat	Long	X	Y			
A196	SOQUIP Pétrofina, Bécancour No 1	46.37	-72.41	699140.79	5138042.62	12.9	1370	7.55
A198	SOQUIP Pétrofina, Bécancour No 2	46.39	-72.39	700814.50	5140665.43	11.8	1265	6.50
A241	Junex, Bécancour No 4	46.38	-72.42	698745.33	5139237.59	8.20	1054	6.10
A246	Junex, Bécancour No 6	46.39	-72.39	701027.30	5140831.13	8.35	1339	6.55
A241vert	simulation well	46.38	-72.42	698681.74	5139305.07	8.20	1440	6.10
A241hz	simulation well	46.38	-72.42	698681.74	5139305.07	8.20	2060	6.10

3D reservoir simulations of CO_2 injection are conducted in the Bécancour area of 2.6 km x 5.4 km (Fig. 1a) in the deep saline aquifer of the Potsdam sandstone at the depth interval of 1.1-1.3 km (Figs 1b, 2). The reservoir simulation grid is built for the Potsdam sandstone (Figs 1, 2). The lateral cell size is 25 m x 25 m, and cell height ranges from 3.5 to 4 m in the Covey Hill reservoir. The total number of cells is 2,060,640. The thickness of the Potsdam Group inside the 3D model ranges from 290 m to 407 m; it consists ~200-300 m for the Covey Hill Formation and 75-110 m for the Cairnside Formation.

The Covey Hill sandstone reservoir is characterized by better flow properties than the Cairnside sandstone (Figs 1b, 2). The core matrix porosity and permeability range from 3.9-13% and 0.13-4.3 mD in the Covey Hill Formation, and they vary from 0.10-3.9% and 0.02-0.52 mD in the Cairnside Formation. The log-derived total porosity and permeability vary from 5-8% and 0.3-2 mD up to ~10 mD in the Covey Hill Formation and to 1.8-3% and 0.03-0.1 mD in the Cairnside

Formation. The overlying units of the Beekmantown and Trenton Groups have low porosity (Fig. 1b) and permeability (Konstantinovskaya et al., 2014; Tran Ngoc et al., 2014) and are considered here as caprock. The Yamaska Fault (Fig. 1) with ~800 m of vertical throw likely has shale smears along the fault plane and behaves as a seal (Konstantinovskaya et al., 2014).

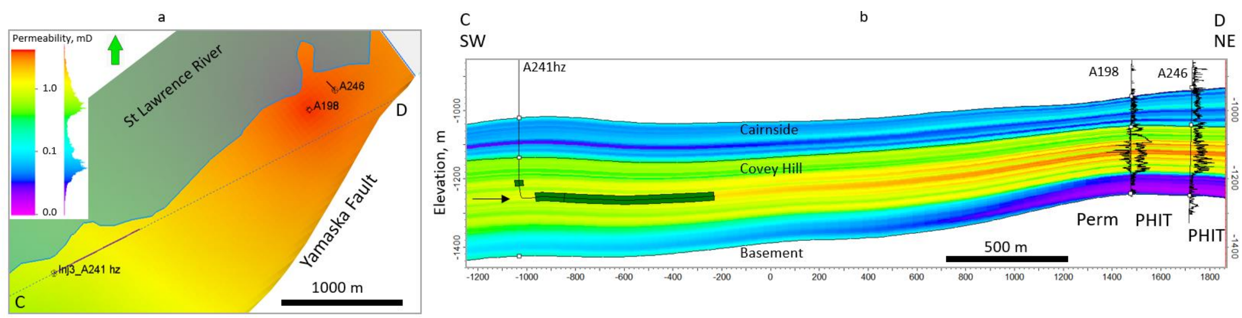

Fig. 2. Map (a) and SW-NE cross-section C-D (b) of the Bécancour model displaying modeled permeability property in the Potsdam sandstone. Well logs of porosity (PHIT) and permeability (Perm) are shown in projected wells A198, A246. The trajectory and completion of the simulation well A241hz are shown. The black arrow in (b) indicates the layer shown in the map (a).

The vertical well A241vert and horizontal well A241hz are designed to simulate CO_2 injections in the Covey Hill sandstone, which is thicker and more permeable than the Cairnside sandstone. The simulation wells are located close to drilled well A241, in the area of relative uplift at the top of the Covey Hill sandstone (Fig. 1, Table 1). The completion of A241vert well included four perforations at the intervals of high porosity and permeability (Fig. 1b). Perforations in A241hz well are planned at the high permeability intervals in the Covey Hill reservoir (Fig. 2). The horizontal section of A241hz well is 814 m long, and it is oriented parallel to the present-day maximum horizontal stress N63°E under the present-day strike-slip faulting stress regime (Plumb and Cox, 1987; Konstantinovskaya et al., 2012).

The initial reservoir pressure is 16.26 MPa (162.6 bar) at a depth of 1336 m bsl based on the drill stem test (DST) data in well A196. The upper limit of the bottomhole pressure (BHP) is set at 20.8 MPa (208 bar), which corresponds to 90% of the lowest total minimum horizontal stress in beds of the Theresa Formation overlying the Cairnside Formation. The applied injection rates are 0.5 kg/s (23117.7 Sm^3/day or 15.8 kt/yr) and 1 kg/s (46235.4 Sm^3/day or 31.5 kt/yr). 3D reservoir simulations were conducted with the option of dual porosity and dual permeability to take into account the presence of natural fractures in the Potsdam sandstone (Konstantinovskaya et al., 2023, 2024).

The 3D reservoir simulation of brine production is conducted in Eclipse 300 to validate reservoir simulations with natural fractures. The simulations are carried out in the Potsdam reservoir model, which is used for the CO_2 injection modeling (Figs 1, 2). We use the data on brine production from deep saline aquifers of the Potsdam and Beekmantown Groups and bottomhole pressure (BHP) data available for well A198 (Fig. 2, Table 1).

The reservoir pressure buildup is analyzed to evaluate the risk of hydraulic fracturing, top seal failure and fault/fracture reactivation.

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Results

1. Injection in vertical well A241vert

After 20 years of injection at the rate of 1 kg/s, the CO_2 plume is up to 475 m in diameter and 400 m in height. The CO_2 injected in the Covey Hill Formation propagated through the fractures to the top of the Cairnside Formation (Fig. 3). At the rate of 0.5 kg/s, the CO_2 plume is ~50 m smaller in diameter and 30 m less in height, but still propagated to the top of the Cairnside Formation (Fig. 4a). For a comparison, in a model with single (matrix) porosity and permeability, under the same injection rate of 0.5 kg/s, the CO_2 plume remains mostly confined within the Covey Hill Formation (Fig. 4b).

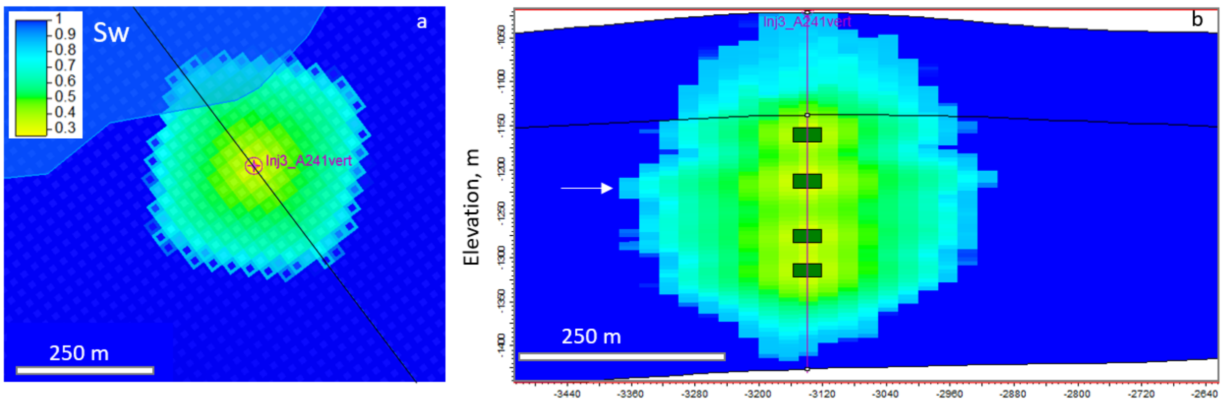

Fig. 3. Map (a) and NW-SE cross-section (b) showing the property of water saturation (Sw) after 20 years of injection for case A241vert, injection rate 1 kg/s, dual porosity, dual permeability. The white arrow on the cross-section indicates the layer location of the map, and the black line on the map shows the location of the cross-section. Sw min 0.26.

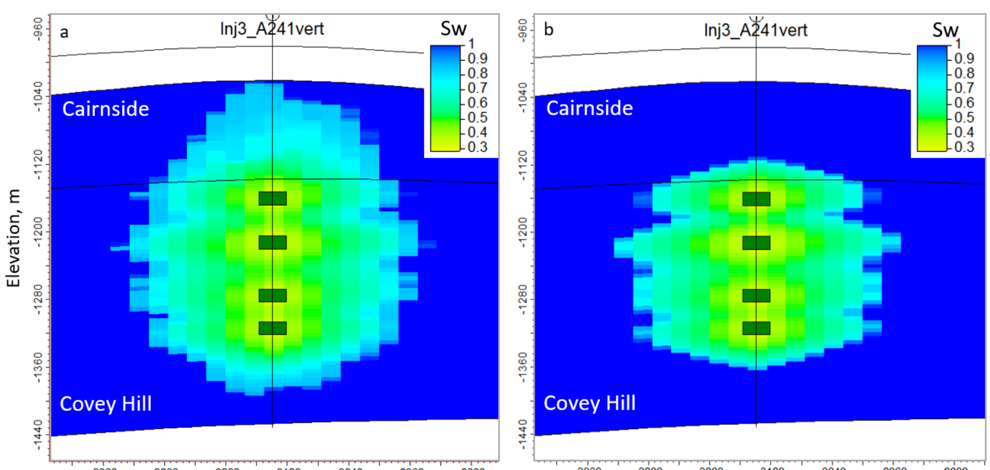

Fig. 4. The NW-SE cross-section showing the property of water saturation (Sw) after 20 years of injection for case A241vert, injection rate 0.5 kg/s for the case with dual (a) and single (matrix) (b) porosity and permeability. Location of the cross-sections is shown by the black line on the map (Fig. 3a). Sw min 0.28 in (a) and 0.269 in (b).

2. Injection in horizontal well A241hz

After 20 years of injection at the rate of 1 kg/s, the CO_2 plume is up to 1125 m long, 425 m wide, and 150 m high. The CO_2 injected in the Covey Hill Formation does not propagate into the Cairnside Formation (Fig. 5), reducing the risk of CO_2 leakage. At the rate of 0.5 kg/s, the CO_2 plume is smaller: 1005 m long, 320 m wife, 130 m high.

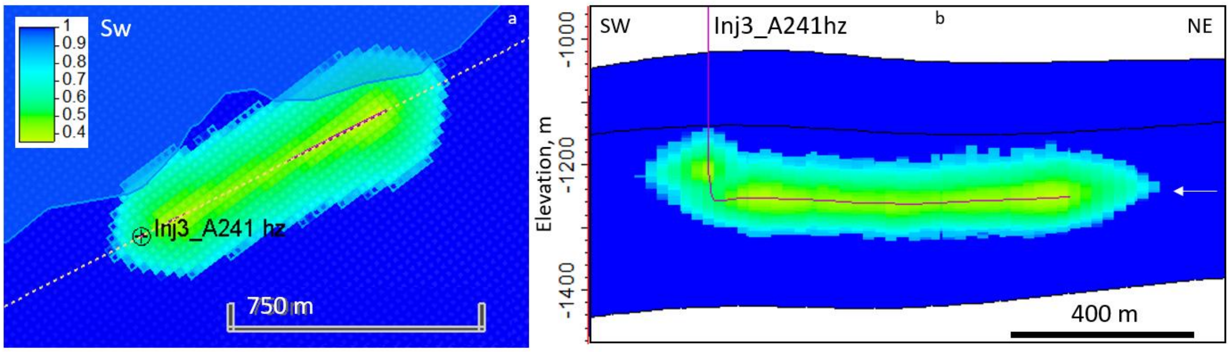

Fig. 5. Map (a) and SW-NE cross-section (b) showing the property of water saturation (Sw) after 20 years of injection for case A241hz, injection rate 1 kg/s, dual porosity, dual permeability. The white arrow on the cross-section indicates the layer location of the map, and the white dashed line on the map shows the location of the cross-section. Sw min 0.35. See Fig. 2b for well A241hz completion.

3. Pressure buildup during the CO_2 injection

The CO_2 injection in A241vert and A241hz at the rate of 0.5 kg/s allows continuous injection for 20 years without reaching the limit of the BHP of 20.8 MPa (Fig. 6). The gas injection cumulative is 315 kt after 20 years of injection either in a horizontal or in a vertical well (Fig. 6).

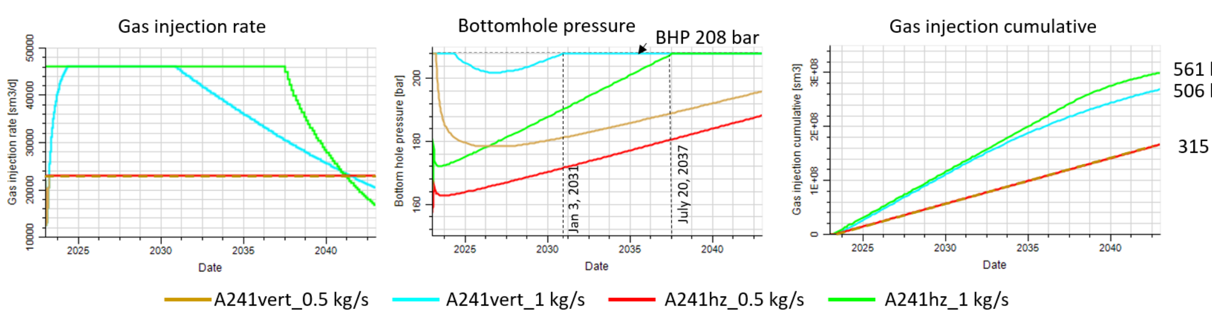

Fig. 6. Charts of gas injection rate, bottomhole pressure (BHP) and gas injection cumulative for 20 years of continuous CO_2 injection in the Potsdam reservoir, simulation cases of dual porosity and permeability, injection rate of 0.5 kg/s and 1 kg/s; injection wells A241vert and A241hz.

The CO_2 injection in A241vert and A241hz at the rate of 1 kg/s allows continuous injection for 8 years and 14.5 years, respectively, before reaching the limit of the BHP of 20.8 MPa (208 bar); after that the injection continues to Jan 2043 at lower (decreasing) rate (Fig. 6). The gas injection cumulative is 506 kt in a vertical and 561 kt in a horizontal well after 20 years of injection (Fig. 6).

The pore pressure buildup is higher above the upper perforation in vertical well A241vert and above the perforation in the horizontal well A241hz after 20 years of injection (Fig. 7). It might be explained by the upward CO_2 migration through the reservoir pore space and natural fractures.

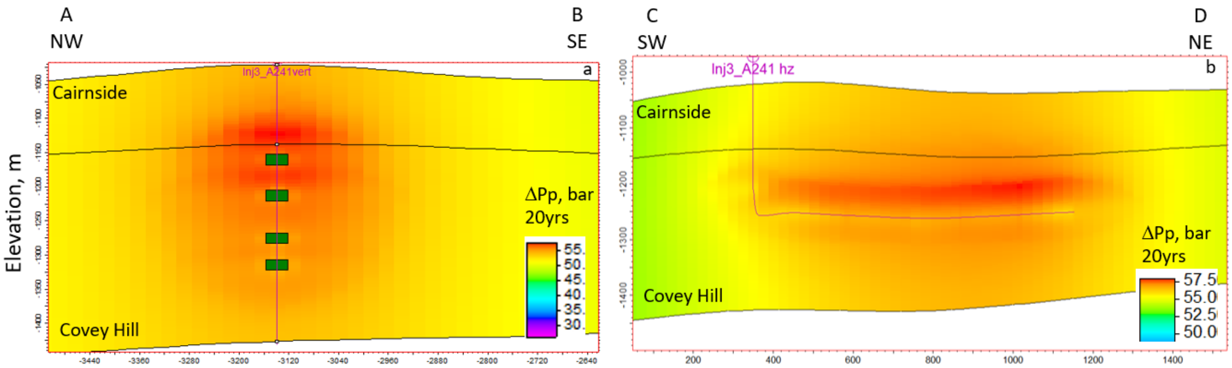

Fig. 7. (a) NW-SE cross-section and (b) SW-NE cross-section displaying reservoir pressure buildup (ΔPp, bar) after 20 years of CO_2 injection in the Potsdam reservoir in vertical (A241vert) and horizontal (A241hz) wells, injection rate of 1 kg/s. See Figs 1a and 2a for the location of the cross-sections.

4. History match for brine production in well A198.

The reservoir simulation of brine production in well A198 was carried out from May 1, 2001, to April 30, 2006 using the Potsdam reservoir model with dual porosity and dual permeability.

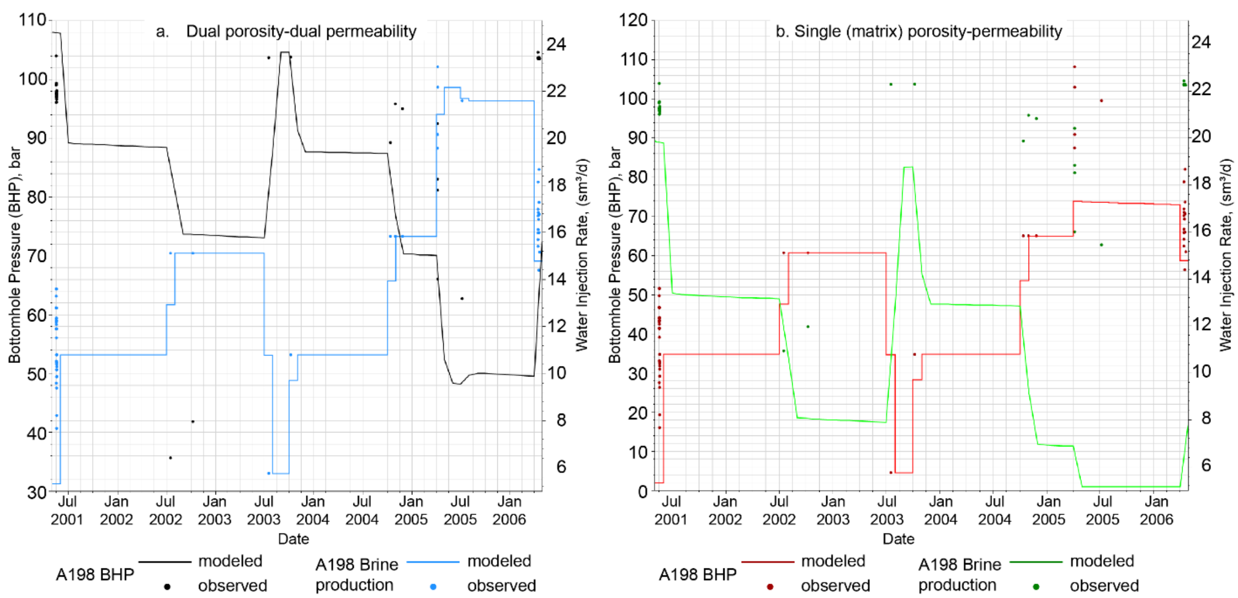

Fig. 8. Charts displaying modeled and observed brine production and bottomhole pressure in well A198 for the reservoir simulations from May 1, 2001, to April 30, 2006 conducted for the Potsdam sandstone model accounting for the presence of natural fractures (a) and without fractures (b).

The observed brine production rate is used as a control mode during the reservoir modeling. The simulated bottomhole pressure (BHP) is reasonably close to the observed BHP (Fig. 8a). The reservoir simulation for the Potsdam sandstone with single (matrix) porosity and permeability, keeping all other settings the same, displays much lower simulated BHP (Fig. 8b). Thus, the reservoir model accounting for the presence of natural fractures reflects more accurately the flow properties of the Potsdam reservoir, if compared to the model without natural fractures.

Conclusions

The simulated CO_2 injection cumulative is 506 kt in a vertical well and 561 kt in a horizontal well after 20 years of injection. The injection in a horizontal well is more effective than in a vertical well as it allows the bottomhole pressure buildup at a lower rate, if compared to a vertical well under the same injection rate (Fig. 6).

The reservoir pore pressure buildup after 20 years of injection at a rate of 0.5 kg/s reaches up to 4.2 MPa (42 bar) in a vertical well, while it is lower, up to 3.7 MPa (37 bar) in a horizontal well. At the injection rate of 1 kg/s, the increase of reservoir pressure is up to 5.73 MPa (57.3 bar) in a vertical well and to 5.79 MPa (57.9 bar) in a horizontal well (Fig. 7). It implies that the risk for tensile failure in the reservoir or above it is very low. Indeed, according to the previous 3D one-way reservoir-geomechanical modeling, cells with negative effective minimum horizontal stress (Shmin_eff) occur at the step of ΔPp of 8 MPa (80 bar). There are only a few thin cells with negative Shmin_eff that appear at the top of the reservoir at ~200 m to the NW from the Yamaska fault after pressure increases by 15 MPa (150 bar), while cells in the overlying units remain intact with positive (compressive) Shmin_eff (Konstantinovskaya et al., 2020).

The pressure buildup in the footwall of the Yamaska Fault, in the vicinity of the fault plane, is about 3 MPa (30 bar) after 20 years of injection in a horizontal well at a rate of 0.5 kg/s, while it is up to 5.4 MPa (54 bar) at a rate of 1 kg/s. Our previous 3D one-way reservoir-geomechanical modeling results (Konstantinovskaya et al., 2020) show that plastic shear deformation along the Yamaska Fault is initiated when reservoir pressure increases by 4-6 MPa (40-60 bar), which occurs only at very small limited areas, while most of the model fault cells fail when pore pressure is increased by 8 MPa. Therefore, injection at 1 kg/s should be conducted with caution, probably aiming at a cycling CO_2 injection strategy (Li et al., 2023).

The history match of brine production in well A198 (Fig. 8) indicates that the reservoir model accounting for the presence of natural fractures reflects more accurately the flow properties of the Potsdam reservoir, if compared to the model without natural fractures.

We suggest that injection in four horizontal wells might be considered as a potential strategy for the CO_2 injection, with two wells oriented to the NE and two wells – to the SW. Additional reservoir simulation is required to quantify the risk of hydraulic fracturing and the Yamaska Fault reactivation.

The estimated reservoir pressure buildup is strongly controlled by the imposed lateral dimensions of the model, while the aquifers area is at least 3 times larger, being limited to the SE and NW by the Yamaska and Champlain Faults, respectively (Konstantinovskaya et al., 2014). We conduct the Eclipse300^{TM} reservoir simulations while taking into account the additional pore volume and evaluate total CO_2 storage capacity using RoseRA^{TM} software.

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