FEASIBILITY OF CO₂ INJECTION IN THE DEEP SALINE AQUIFERS OF THE BÉCANCOUR REGION, QUÉBEC (CANADA)

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ABSTRACT
The feasibility of CO₂ injection in a reservoir of the Bécancour region was investigated using 2D radial numerical simulations with TOUGH2/ECO2N. To optimize the CO₂ injection rate and the duration of injection, we carried out sensitivity analyses considering different values of completion interval for the single injection well, rock compressibility, and the ratio of vertical and horizontal permeabilities. Simulations took into account Bécancour reservoir conditions, in which injection pressure was limited below the fracturing threshold, and sensitivity analyses provided indications of potential injection scenarios.

To remain below fracturing pressure, we propose intermittent 5-year injection periods, with a mass injection rate up to 20 kg/s, alternating with half-year periods without injection. This scenario may provide maximum CO₂ storage in the aquifer. We also calculated CO₂ storage capacities in different phases versus time. The effective apparent capacity and injection capacity estimated by the dynamic method, as well as effective storage capacity factors, were rigorously redefined on a mass and volume basis. For comparison purposes, CO₂ storage capacity was also estimated using volumetric and compressibility static methods. The storage efficiency factor obtained from the TOUGH2 dynamic method is about 1.5%, but it ranges between 2.2% and 3.3% for the static methods.

This study shows that the northeastern reservoir block of the Bécancour region could host ~10 Mt CO₂, which represents 15% to 50% of regional yearly CO₂ emissions over a few decades (depending on the injectivity scenario).

Finally, this modeling study will also be the basis for the design of a pilot CO₂ injection test.

INTRODUCTION
According to a basin-scale assessment for different onshore and offshore basins in Southern Québec, Canada (Malo and Bédard, 2012), the St. Lawrence Platform has the best potential for CO₂ storage in Quebec. Within the St. Lawrence basin, the Bécancour region, located between Montréal and Québec City along the St. Lawrence River, was selected for a site-scale study, because of data availability inherited from hydrocarbon exploration, as well as significant CO₂ production in the area (of about 1 Mt per year) from a cluster of stationary emitters. Deep saline aquifers in this region were characterized in terms of hydrogeology and petrophysics to assess their potential use for CO₂ sequestration. The brine-bearing sandstones of the Potsdam Group were recognized as the most favorable unit for a CO₂ injection (Tran Ngoc et al., 2011). The output of this characterization is summarized in this paper.

Based on a framework for the feasibility assessment of storage capacity, injectivity and integrity of specific sites, this paper presents the feasibility of supercritical CO₂ injection into the northeast reservoir block of the Bécancour region, using a series of 2D radial numerical simulations of multiphase flow and transport of H₂O-NaCl-CO₂ components. The parameterization analysis of hydrogeological properties controlling pressure buildup and CO₂ plume migration during and after injection (Doughty, 2010) is used with a dual purpose. On one hand, this sensitivity study offers an insight into the uncertainty related to our present knowledge of reservoir properties. On the other hand, the
relative advantages and disadvantages of conditions and properties at the Bécancour site as they relate to CO₂ storage are displayed by our simulation results and thus can now be compared to conditions and properties at other sites worldwide. Simulations provide estimated values for storage capacity, indicate potential storage injection scenarios (i.e., CO₂ distribution versus time) and feasible injection rates. This study also provides a comparison between CO₂ storage capacities estimated from several approaches.

SITE CHARACTERISTICS

The saline aquifers of the Bécancour region are part of the Paleozoic sedimentary succession of the St. Lawrence Platform, at depths ranging from 800 to 2400 m. Their lithostratigraphy, identified by well-log correlation and seismic line interpretation (Claprood et al., 2012), consists mainly of the following units: Potsdam Group (Covey Hill and Cairnside sandstones), Beckmantown Group (Theresa and Beaufort dolostones) and Trenton Group (Chazy, Black-River and Trenton limestones). These saline aquifers are overlain by a cap rock of > 800 m thick shales and siltstones of the Utica Shale and Lorraine Group. The regional reservoir is separated by the SW-NE Yamaska normal fault into two faulted blocks found at different depths. In the present paper, we study CO₂ injection into the upper northeastern block of the fault.

All rock units are subhorizontal strata with excellent lateral continuity and small thickness variation. The units of the Potsdam Group, i.e., Covey Hill (CH) and Cairnside (CA) Formations, are the most porous, most permeable and thickest units of the sedimentary succession. Hydrogeological and petrophysical properties of these units are reported in Table 1. The fracturing pressure of Bécancour reservoir units was derived from minimal horizontal stress calculated in the St. Lawrence Platform basin (Konstantinovskaya et al., 2012). The compressibilities of Potsdam porous rock were determined from core measurements of porosity and net overburden pressures, and compared to literature values (Figure 1).

Capillary properties of Potsdam sandstones were based on measurements made on core samples using both mercury injection and capillary centrifuge tests. The van Genuchten (1980) model for capillary pressure (CP) and the Genschen-Mualem (VGTM)/Corey model (Corey, 1954) for relative permeability (RP) was fitted to laboratory measurements (Table 2).

![Figure 1. Correlation of rock compressibility with porosity for Covey Hill and Cairnside Fm.](image)

**Table 1. Main representative properties of Covey Hill and Cairnside Fm.**

<table>
<thead>
<tr>
<th>Property</th>
<th>CH</th>
<th>CA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity $\varphi$ [%]</td>
<td>6.0</td>
<td>3.5</td>
</tr>
<tr>
<td>Horiz. permeability $k_r$ [mD]</td>
<td>0.89</td>
<td>8.9</td>
</tr>
<tr>
<td>Vert. permeability $k_z$ [mD]</td>
<td>0.12</td>
<td>0.06</td>
</tr>
<tr>
<td>Global permeability $k$ [mD]</td>
<td>4.17/100&lt;sup&gt;a&lt;/sup&gt;</td>
<td></td>
</tr>
<tr>
<td>Pressure gradient $\Delta P_h$ [MPa/km]</td>
<td>12.17</td>
<td></td>
</tr>
<tr>
<td>Min horiz. stress $\Delta S_{min}$ [MPa/km]</td>
<td>20.5</td>
<td></td>
</tr>
<tr>
<td>Surface temperature $T_{surface}$ [°C]</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Temperature gradient $\Delta T$ [°C/km]</td>
<td>23.5</td>
<td></td>
</tr>
<tr>
<td>Salinity $TDS$ [g/l]</td>
<td>109</td>
<td>242</td>
</tr>
<tr>
<td>Rock compressibility $c_r$ [1/Pa]</td>
<td>$2 \times 10^{-9}$</td>
<td>$4 \times 10^{-9}$</td>
</tr>
</tbody>
</table>

<sup>a</sup>: determined from drill stem tests for CA with 4.17 = geometric average and 100 = arithmetic average; 1 mD = 1×10<sup>−15</sup> m².

Capillary properties for the CO₂-brine fluid system were obtained based on conversions from air-mercury and air-brine systems, using the experimental correlation of interfacial tension between CO₂ and brine proposed by Bachu and Bennion (2009). Figs 2 and 3 depict the capillary pressure and relative permeability
curves, respectively. Note that the residual liquid saturation $S_{lr}$ [-] was estimated from sets of measured and deduced saturation values.

The residual gas saturation $S_{gr}$ [-] was determined from Land’s equation (Land, 1969), when assuming the liquid saturation at the drainage-to-imbibition turning point is equal to $S_{lcentral}$, the central saturation of the drainage branch, and $S_{grmax}$ is the maximum saturation difference between the drainage and imbibition branches of capillary pressure curves.

![Figure 2. Capillary pressure as a function of fluid saturation for Covey Hill (lower) and Cairnside (upper) Fms.](image)

<table>
<thead>
<tr>
<th>Capillary properties</th>
<th>CH</th>
<th>CA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Saturated liquid saturation $S_{lr}$ [-]</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Residual liquid saturation $S_{lr}$ [-]</td>
<td>0.27</td>
<td>0.33</td>
</tr>
<tr>
<td>Residual gas saturation $S_{gr}$ [-]</td>
<td>0.26</td>
<td>0.21</td>
</tr>
<tr>
<td>Exponent $m$ [-]</td>
<td>0.558</td>
<td>0.621</td>
</tr>
<tr>
<td>Entry pressure $P_{hcap}$ [Pa]</td>
<td>$4.4 \times 10^4$</td>
<td>$4.0 \times 10^4$</td>
</tr>
</tbody>
</table>

Figure 3. Relative permeability as a function of fluid saturation for CH (solid lines) and CA (dashed lines) Fm. according to the VGTM and Corey model.

**NUMERICAL MODEL**

The mathematical model of supercritical CO$_2$ injected and stored in deep saline aquifers was numerically implemented in TOUGH2/ECO2N (Pruess, 2005). We used this code for numerical simulations that were carried out in isothermal and non-hysteretic mode, considering transport only by convection from CO$_2$ injection and gravity. Certain processes were disabled, such as molecular diffusion, hydrodynamic dispersion, and permeability changes from salt precipitation, rock dissolution, or mineral carbonation.

**Conceptual and numerical model**

The area of the northeastern reservoir block targeted for CO$_2$ injection is referred as $A$ [L$^2$], which is 7 by 5 km, equivalent to the circular surface with a radius of 3.3 km used in the model. The model consists of the Potsdam sandstones found at 1102–1503 m TVD with a thickness $h$ [L] of 288 m for the Covey Hill Fm. and 113 m for the Cairnside Fm.

A two-dimensional (2-D) radial grid model was used to represent a cylindrical volume with central symmetry for the CO$_2$ storage site. Two homogeneous strata of Covey Hill and Cairnside sandstones are represented in the model, in which a vertical injection well is centered with an open-hole interval completed over the entire thickness of the Covey Hill Fm. A representative inner casing diameter of 0.15 m of other Bécan-cour boreholes was assumed for the injection well. Radial layers were discretized into 100 gridblocks, with finer meshing in the vicinity of the well using a logarithmic factor of ~1.085,
which allows us to create the radius of the first gridblock size equal to one of the injection wells. The vertical computational domain has a grid resolution of 25 layers (the Covey Hill Fm.) and 10 layers (the Caernarfon Fm.). All vertical cells are about 11 m thick.

**Initial and boundary conditions**

Table 3 summarizes the model initial conditions, based on site characterization data. All reservoirs above the Potsdam sandstones, together with cap rocks and the Grenville basement, are considered as sealing units. Therefore, the top and bottom of the model are impervious boundaries. Finally, CO2 injection was presumed to be made into a closed volume system (Zhou et al., 2008).

<table>
<thead>
<tr>
<th>Initial conditions</th>
<th>CH</th>
<th>CA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrostatic pressure $P_{topCt}$ [MPa]</td>
<td>-</td>
<td>13.41</td>
</tr>
<tr>
<td>Temperature at top $T_{top}$ [°C]</td>
<td>36.6</td>
<td>33.9</td>
</tr>
<tr>
<td>Salt mass fraction $X$ [-]</td>
<td>0.098</td>
<td>0.195</td>
</tr>
<tr>
<td>CO2 saturation [-]</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CO2 solubility in brine [g/l]</td>
<td>42.32</td>
<td>28.15</td>
</tr>
<tr>
<td>NaCl brine density [kg/m³]</td>
<td>1140</td>
<td>1059</td>
</tr>
<tr>
<td>CO2 density [kg/m³]</td>
<td>801</td>
<td>803</td>
</tr>
<tr>
<td>NaCl brine viscosity [Pa.s]</td>
<td>1.2×10⁻³</td>
<td>8.3×10⁻⁴</td>
</tr>
<tr>
<td>CO2 viscosity [Pa.s]</td>
<td>7.2×10⁻⁵</td>
<td>7.3×10⁻⁵</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Boundary conditions</th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Top $z = -1102$ m:</td>
<td>no-flow</td>
<td></td>
</tr>
<tr>
<td>Bottom $z = -1503$ m:</td>
<td>no-flow</td>
<td></td>
</tr>
<tr>
<td>Lateral $r = 0$:</td>
<td>mass injection</td>
<td></td>
</tr>
<tr>
<td>Lateral $r = 3300$ m</td>
<td>no-flow</td>
<td></td>
</tr>
</tbody>
</table>

Note: fluid properties correspond to the unit top

**SENSITIVITY SIMULATION RESULTS**

Simulations took into account Bécancour reservoir conditions in which injection pressure was limited below the fracturing pressure. This pressure is determined from thresholds for fracturing all rocks and displacing native caprock fluid by CO2 (i.e. capillary pressure strength of caprocks) (Rutqvist et al., 2007). Here, the maximum sustainable injection pressure $P_{max}$ stemmed from only $S_{min}$ with a factor of 0.9 according to regulatory agencies, due to a lack of data on caprock units. The simulation base case used parameters from Table 1 and Table 2 with the Corey model for the relative permeability curves. Sensitivity analyses were carried out by varying only the Covey Hill parameters. Simulations considered injection periods of 5 to 50 years and a few hundred years thereafter, following stoppage of injection. We used the Petrasim interface for TOUGH2 simulations (Thunderhead-Engineering, 2010).

**Hydrodynamic parameter effects**

![Figure 4. Pressure buildups versus time in the two cases using $k_{tr}$ from the Corey model (base case) and VGT model.](image)

A mass injection rate of 4.5 kg/s for 10 years was applied at the injector for the base case without fracturing reservoir rocks. The pressure buildup would be double the maximum sustainable threshold (0.9$S_{min}$) if simulations used the $k_{tr}$ of CH Fm. from the VGT model (Figure 4). The overpressure of the base case (Corey $k_{tr}$) is smaller than the one for the case using VGT $k_{tr}$, because the larger Corey $k_{tr}$ (Figure 3) facilitates the displacement of injected brine by CO2. The pressure transient for the case with VGT $k_{tr}$ has large oscillations, whereas it is very smooth for the case of Corey $k_{tr}$. This problem is not only attributed to discretization effects, but also to utilization of a hydrodynamic model. These oscillations occur due to density differences between phases whenever the CO2 moves from one gridblock to the next in the radial direction. The oscillation effect may be attenuated with simulations using a 3D heterogeneous model.

The pressure buildup increases with a decrease of $S_{gr}$ (not shown here), owing to the RP Corey model, in which $k_{tr}$ decreases, i.e., overpressure increases, as $S_{gr}$ decreases. The difference in the
overpressure is about 0.7 MPa between the two cases of $S_{gr} = 0$ and $S_{gr_{max}} = 0.4$.

**Petrophysical parameter effects**

Injectivity is always proportional to reservoir permeability. Figure 5 shows the maximal injection rates with an injection period of 10 years as a logarithm function of the horizontal permeabilities $k_r$ that are in the possible range for the target Covey Hill Fm. The maximal injection rate increases faster when $k_r < 5$ mD than $k_r > 5$ mD.

![Figure 5](image_url)  
**Figure 5.** Injection rates used for 10 years as a function of horizontal permeability $k_r$ of Covey Hill Fm.

For the vertical permeability $k_z$, well injectivity is not considerably changed due to bottomhole pressure buildup (not shown here) for $k_z$ in the range from 0.012 to 1.2 mD. While $k_z$ is not significant for the injection rate, its range of 0.01–0.1 mD being much less than $k_r$ ($k_r/k_z = O(10^2)$) plays a role in delaying CO$_2$ buoyancy (not shown here). Thus, the storage formations themselves also contribute to secure sequestration of CO$_2$ by preventing upward migration.

Overpressures changed slightly in simulations (Figure 6) when estimated compressibility varied from $1\times10^{-9}$ to $3\times10^{-8}$ Pa$^{-1}$, comparable to the range of measured values (Figure 1). While the injection rate had only to be slightly decreased to 4 kg/s (from 4.5 kg/s for base case) to meet the sustainable threshold for the overpressure in the case using a Covey Hill compressibility of $2\times10^{-10}$ Pa$^{-1}$, it could be increased to about 7 kg/s (factor of 1.5) for the case of $2\times10^{-8}$ Pa$^{-1}$, and still not exceed the threshold (Figure 6).

![Figure 6](image_url)  
**Figure 6.** Pressure buildups versus time in the cases of Covey Hill Fm.’s different compressibility coefficients.

**STORAGE SCENARIOS**

**Scenario description**

The sensitivity analysis in the previous section shows that the base-case model parameters involve a certain robustness in the injection characteristics of the site. So, from the base case, scenarios of CO$_2$ injection are proposed that aim to assess reservoir storage capacity.

To use the maximum storage capacity of reservoirs, we tested the strategy of intermittent CO$_2$ injections. The injection rates and durations were estimated such that the induced aquifer pressures would not only be limited to the maximum sustainable pressure threshold of $0.9S_{min}$ within the injection periods, but also they would not exceed 1.3 $P_h$ in the post-injection phase. Two proposed injection scenarios correspond to two cases of Covey Hill horizontal permeability, $k_r = 0.89$ mD and $k_r = 4.17$ mD. The latter belongs to the Cairnside Fm., but was used in simulations. While the small injection rates and a series of injection periods (~total 65 years) are applied in the case with $k_r = 0.89$ mD, the injection rates are large with only 3 injection periods in the case with $k_r = 4.17$ mD (~total 16.5 years) (Figure 7). The relaxation time between two intermittent injection periods is 0.5 years in both cases. It is not surprising that the cumulative injected CO$_2$ mass are at in the same order of magnitude regardless of the injection scenarios, considering the intrinsic storage capacity of the reservoir.
**CO₂ plume migration**

The spatial distribution of the supercritical CO₂ plume at \( t = 100 \) yrs for the two injection scenarios is presented in Figure 8. After the end of injection, the CO₂ plume migrates far from the injection point with only natural convection generated from the density difference between CO₂ and formation brine. In the scenario with \( k_r \) corresponding to the base case, the CO₂ front shows almost no advance in the Covey Hill Fm. beyond its extent at the end of injection, but there is continuous upward CO₂ migration in the Cairnside Fm. (Figure 9). CO₂ leaves the injection formation due to the permeability contrast between the two formations. This observation may be less visual in the scenario with CH \( k_r = 4.17 \) mD (Figure 8). Three hundred years after the onset of injection, supercritical CO₂ was detected at \( \sim 570 \) and \( 1130 \) m of radius of the cylindrically spreading plume in the Covey Hill and Cairnside Fm., respectively, for the case with CH \( k_r = 0.89 \) mD and \( \sim 680 \) and \( 950 \) m for the case with CH \( k_r = 4.17 \) mD.

\[
M_{\text{tot}} = M_{\text{immisc}} + M_{\text{aq}} = (S_g \rho_g)(\theta) V + (S_l \chi CO_2 \rho_l)(\theta) V \\
V_{\text{tot}} = V_{\text{immisc}} + V_{\text{aq}} = (S_g)(\theta) V + n V_{\text{partial}}
\]
where \( M_{\text{tot}} / V_{\text{tot}} \) are the CO₂ total mass/volume that can be stored into the aquifers, \( M_{\text{immisc}} / V_{\text{immisc}} \) are the mass/volume of immiscible CO₂ (gas-like phase) made up of the mobile CO₂ plume (\( M_{\text{mob}} / V_{\text{mob}} \)) and residual CO₂ trapped in pores (\( M_{\text{immob}} / V_{\text{immob}} \)), and \( M_{\text{aq}} / V_{\text{aq}} \) are the mass/volume of CO₂ dissolved in the aqueous phase. The sign \(<\) stands for volume average over all domain (thus the “global” qualification used) taking into account the effect of formation geometry and heterogeneity, \( V = A \times h \ [\text{L}^3] \) is the volume of aquifer (bulk volume). Note that \( V_{\text{aq}} \) is deduced from the apparent partial molar volume of CO₂ dissolved \( V_{\text{partial}} \) [L³ per mole], which only depends on the reservoir temperature (Pruess, 2005). \( n \) [mole] is the number of moles of CO₂ dissolved in the aqueous phase:

\[
n = \frac{\left( S_i X_i^{\text{CO}_2} \rho_i \right) V}{m_{\text{CO}_2}}
\]

From Doughty et al. (2001), the global storage efficient capacity factor \( C_{\text{dyn}} \ [-] \) is revisited as follows:

\[
C_{\text{dyn}} = C_{g-\text{mass}} + C_{l-\text{mass}}
\]

where \( C_{g-\text{mass}} \) (including \( C_{g\text{mob}} \) and \( C_{g\text{immob}} \)) and \( C_{l-\text{mass}} \) [-] are efficiency factors of gas- and liquid-phase components. These factors can be defined on a mass or volume basis, assuming that the theoretical mass of CO₂ \( M_{\text{theory}} \) stored in the entire pore space saturated with a gas-like CO₂ phase corresponds to \( C = 1 \):

\[
C_{g-\text{mass}} = \frac{M_{\text{immisc}}}{M_{\text{theory}}} = \frac{\langle s \rangle}{\rho_g}
\]

On a volume basis,

\[
C_{l-\text{vol}} = \frac{V_{\text{immisc}}}{V_{\text{pore}}} = \frac{V_{\text{partial}}}{M_{\text{CO}_2}} \langle \rho \rangle \left( S_i X_i^{\text{CO}_2} \rho_i \right)
\]

where \( V_{\text{pore}} = \langle \theta \rangle V \) [L³] is the total pore volume of aquifer.

**Results and comparison**

From the TOUGH2 results obtained for the two injection scenarios (Figure 8), the evolutions with time of different forms of CO₂ are shown in Figure 10: dissolved CO₂ in liquid-phase, mobile and immobile CO₂ in gas-like phase of stored CO₂ mass. The storage capacity (290 kg per m²) of the scenario with \( k_r = 4.17 \text{ mD} \) is greater than that of the scenario with \( k_r \) base case (270 kg per
m$^3$) according to the contribution of all CO$_2$ forms in place within the injection time. Nonetheless, only the immobile CO$_2$ quantity ($M_{\text{immob}}$) is greater in the case with $k_r = 4.17$ mD than in the case with $k_r$ of the base case after the end of injection, because the larger permeability allowed CO$_2$ to travel within a large zone in which much CO$_2$ was trapped as residual saturation. Dissolved CO$_2$ ($M_{\text{sol}}$) is almost the same in both scenarios and mobile CO$_2$ ($M_{\text{mob}}$) is slightly smaller in the case of $k_r = 4.17$ mD than in the case of $k_r$ for the base case. Finally, the apparent capacity of the scenarios was expressed by $\sim 1.1 \times 10^7$ m$^3$ of stored supercritical CO$_2$ or $\sim 0.32$ m$^3$ per m$^2$ of site surface (not shown).

Figure 11 presents the evolution of the storage efficiency factors versus time obtained on a mass and volume basis. As expected, the capacity factor of liquid phase is greater for the mass basis than in the volume basis, while the capacity factors of gas-phase remain the same for both approaches. Consequently, the global capacity factor is larger (but not by much) on a mass basis than for the volume basis. It can be seen that the increase in the capacity factors of dissolved and trapped CO$_2$, and the decrease in the capacity factor of free CO$_2$ with time, enhances the storage security of the site.

The storage capacity was also calculated by static methods after estimating efficiency factors (not shown here). The factors from the hydrodynamic contribution were estimated by using their relations to non-dimensional numbers such as the mobility ratio and capillary number proposed in the oil-gas engineering literature. The site storage capacity factor was obtained by using the mass basis. It is 3.3%, which falls within the range (0.51%–5.4% for elastic lithology) determined by the Monte Carlo probability (Goodman et al., 2011). Note that in the compressibility method, we estimated the efficiency factor (2.19%) when calculating the maximum pressure buildup at the center of formations, corresponding to $0.95s_{\text{min}}$.

The storage capacities of the northeastern reservoir block of the Bécancour region corresponding to the efficiency factors of all the estimates are shown in Figure 12. The stored CO$_2$ mass obtained from the TOUGH2 dynamic method is smaller than the one of the static methods. The difference is $\sim 30\%$ between the TOUGH and compressibility method and $\sim 50\%$.

![Figure 10. Evolution of different forms of cumulated CO$_2$ stored in place with time from the injection scenario with $k_r$ of the base case and dashed lines for $k_r = 4.17$.](image)

![Figure 11. Capacity factors as a function of time for the scenario with $k_r$ of the base case (solid lines for the mass basis and dashed lines for the volume basis).](image)

![Figure 12. Storage capacity as a function of storage efficiency factors. Comparison between different estimation sources.](image)
between the TOUGH and volumetric method. $M_{\text{theo}}$ and $C_{\text{d}}$ pairs of the dynamic method are linearly related between the storage capacity and efficiency factor. That reflects the fact that the theoretical mass of CO$_2$ stored in all the pore space is almost the same in all the methods, because the average CO$_2$ density over the entire reservoir domain by the TOUGH2 simulations is not much different from the estimated values in the static methods.

**DISCUSSION AND CONCLUSIONS**

The numerical sensitivity analysis documented in this paper highlights the influence of site properties, pressure constraints, and injection regime on the injection characteristics and thus the storage capacity. Permeability has the most direct impact on injectivity relative to other parameters (such as well diameter, thickness and depth of host formations, degree of CO$_2$ dissolution, compressibility, and permeability anisotropy), whereas capillary parameters have a global impact. In fact, simulation results for CO$_2$ injection could depend significantly on the capillary model used, at least for this study. The permeability contrast in the site favors preferential horizontal flow and impedes the upward migration of CO$_2$. From the point of view of security relative to CO$_2$ leakage risk, a compromise is needed between the completion interval and the injection rate in relation to vertical permeability. It is clear that greater rock compressibility plays a more important role for the aquifer pressure response. In this study, we did not investigate the sensitivity for the CA parameter, particularly for its permeability, for instance, CA $k_c > CH k_z$; this contrast could not force out the CO$_2$ plume remaining in the CH Fm. after the end of injections.

The injection strategy with intermittent steps was applied in two proposed injection scenarios representing two cases: 1) $k_c < 1$ with long injection duration, and 2) $k_c > 1$ mD with short injection duration. The radial plume of injected CO$_2$ extended less than 1.2 km around the injection well. The total amount of CO$_2$ injection was on the order of 10 Mt for the two scenarios, which could be equivalent to regional emissions for ten years. Thus, the present geological sequestration option might consume 15%–50% of regional yearly CO$_2$ emissions in the few first decades from the start of injection. This annual emission of Bécancour would be all hosted in its deep saline aquifers by using vertical and/or horizontal multi-injectors.

The storage capacity estimated by the TOUGH2 simulations is smaller than the one obtained from static methods, because simulations take into account hydrodynamic multiphase processes that are not considered by static methods. It is also difficult to compare with the static volumetric method because of different hydraulic regimes. To compare with the static compressibility method, we modeled the aquifers as closed-system, which is suitable for Bécancour aquifers because no regional flow is observed and because it has small permeability. The efficiency capacity factors defined herein by the dynamic method are a function of time, but the global factor does not decrease after the end of injection. This is contrary to the efficiency capacity factor estimated for the reservoir with lateral spill points in Doughty et al. (2001). However, the local capacity factors, if calculated over a local domain (Doughty et al., 2002) in the closed aquifers, would increase or decrease with time. The application domain was defined for the storage capacity estimates and efficiency capacity factors of the TOUGH dynamic method.

The feasibility assessment of CO$_2$ injection in the deep saline aquifers of the Bécancour area (Québec) was carried out using TOUGH2 2D radial simulations, in which the injectivity and storage capacity estimates were investigated by the sensitivity study and the injection scenarios. A more detailed analysis will be presented in the forthcoming journal paper. These are the first numerical simulations showing the supercritical CO$_2$ behavior once the CO$_2$ is injected into the St Lawrence Lowlands salty sediment. This study is also a useful base for assessing seismicity induced by injection and leakage risk. A heterogeneous hydrodynamic model for the Bécancour reservoir will be developed on the basis of new data, especially the hydrogeology and petrophysical properties of cap rocks. The injection characteristics will be better mastered with the *in situ* permeability of the CH Fm. that will be established from field measurements. Finally, other processes involved in multiphase
flow and transport not yet taken into account in this study, such as capillary hysteresis, permeability modification, and diffusion-dispersion, are planned for future research.

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