Geotechnical characterization of deep saline aquifers for CO₂ geological storage in the Bécancour region, Québec, Canada

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Keywords: CO₂ geologic sequestration, hydrogeological and petrophysical characterization, deep saline aquifer, reservoir engineering, Bécancour -Québec.

ABSTRACT: Hydrogeological and petrophysical characterization of deep saline aquifers was carried out to assess CO₂ storage potential in deep saline aquifers of the Bécancour region. Profiles of formation pressure, temperature, density, viscosity, porosity, permeability and net pay were established for each Paleozoic sedimentary aquifer. Lateral hydraulic continuity is dominant at the regional scale. The Covey Hill sandstone is the most suitable saline aquifer for the CO₂ storage, with pressure $\geq 14$ MPa, temperature $\geq 35$ °C, salinity $\approx 109$ g/l, permeability $\approx 0.3$ mD, porosity $\approx 6\%$, net pay $\approx 188$ m and pore volume per surface $\approx 12$ m³/m². This characterization provides the required information to proceed to the next steps of CO₂ injection numerical simulation and risk assessment.

1. INTRODUCTION

The utilization of fossil fuels currently occupies 90% of the total primary energy sources and it will remain predominant for the World’s economic growth in the next decades. This use has released an enormous amount of carbon dioxide (CO₂), one of the most prevalent greenhouse gases (GHG) (DOE-US, 2010). The anthropogenic global CO₂ emissions attained ~31.3 Gt, of which the USA releases about ~5.6 Gt, Canada 0.56 Gt, China 6.8 Gt and Viet Nam 0.11 Gt (2007 data; Boden et al., 2011). While CO₂ emissions of developed countries has ceased to increase in recent years, CO₂ emissions from emerging and developing countries still increases each year (Boden et al., 2011), due to available low cost fossil-fuel reserves and limited development of clean environmental solutions. For example, a series of coal-fired power plants has been installed in Viet Nam over the past decade with the scope of opening 58 plants in 2030 (~ one plant per province) (source: Baocongthuong). In the USA, 150 coal-burning utilities are planned for 2030 (~600 existing plants) with the proposed technology of IGCC-CCS (Integrated Gasification Combined Cycle-Carbonate Capture and Storage) (source: Sourcewatch; VNA News).

The negative impacts of GHG on global climate change are directly relative to the increase of the CO₂ emissions. To mitigate these impacts, the long-term concentration of CO₂ in the atmosphere must be limited to ~450 ppm (parts per million) in order to attain the target of limiting the global rise in temperature below 2 °C (source: IEA). In the portfolio of mitigation options, CCS technologies are considered by many scientists to complete a closed cycle for fossil fuel use and promise a substantial mean for reducing CO₂ emissions. CO₂ geological sequestration consists of different storage approaches, such as saline formations, depleted oil/gas fields, enhanced recovery in oil/gas reservoirs, coal beds and offshore basins. CCS has a huge potential in several countries. CO₂ storage in deep saline aquifers has an estimated worldwide capacity of approximately 1000 to 10000 Gt of CO₂ (IPCC, 2005).

The CO₂ stored under field conditions in deep saline aquifers will be in a supercritical form during the complex physical and chemical processes of multiphase and multi-component flow and transport processes related to CCS. Five CO₂ storage mechanisms have been identified: structural-stratigraphic, hydrodynamic, residual, solubility and mineral trappings (IPCC, 2005). Secure storage increases with time, after cessation of CO₂ injection (Bachu et al., 2007). Site characterization of potential CO₂ sequestration sites is crucial to support the numerical modeling of storage mechanisms. The Cambrian-Ordovician St. Lawrence Lowlands sedimentary basin, in southern Québec, has been assessed as the most prospective basin in Québec according to geological and practical criteria for CO₂ storage (Malo and Bédard, 2011). In the present paper, the characterization of the deep saline aquifers in the Bécancour region of St. Lawrence Lowlands is presented in terms of hydrogeology and rock petrophysics at the site-scale. This region is close to large CO₂ stationary sources producing 1Mt/year and there is good data availability related to past hydrocarbon exploration.
2. DATA AND METHOD

The Bécancour study area is located between Montréal and Québec City in the St. Lawrence lowlands (Fig. 1). An abundance of hydro-geological and geophysical data from petroleum and gas exploration is available in this region (Tran Ngoc et al., 2011).

Seismic lines covering the 270 km² of the Bécancour site were used to delineate the lateral and vertical extents of saline aquifers (Fig. 2). Geological data, well logs, well tests and petrophysical data were obtained from 20 Bécancour boreholes, of which 8 are located in close vicinity (Fig. 2). Two-way time (TWT) seismic profiles were converted to depths using kriging and data from well logs (Konstantinovskaya et al., 2010; Claprood et al., 2011). Formation tops were established for each seismic profile. Four regional sections using well-to-well correlation were built from 25 wells to determine regional lithostratigraphic facies variations (Bédard et al., 2010).

Formation pressures, temperature and salinity were determined from drill stem tests (DSTs) and production tests. The in situ hydrostatic pressure and permeability of potential reservoir units were obtained from Horner plot analysis of DST results. Production tests indicated artesian flow in some wells. Geothermal temperatures were recorded during each DST in different units. Formation temperatures profiles were also recorded in boreholes from well logs. Formation fluids were sampled by a water separator from DSTs or during well production to analyze the chemical composition, including total dissolved solids (TDS = salinity). Beside laboratory analysis, some major parameters such as density and salinity were measured in situ. Density and viscosity of formation water can be estimated from the known salinity using Batzle and Wang’s algorithm (1992). CO₂ states can also be predicted under the Bécancour aquifer conditions using the formula of Span and Wagner (1996).

Available drill cores covering all aquifer intervals were taken from 19 regional boreholes. Petrophysical measurements included porosity, permeability and grain density. Also, the 3 principal permeability components were measured on full cores. The 800 available measurements from 260 m of cores are numerous enough to be statistically analyzed. A porosity cutoff corresponding to a permeability of 0.1 mD (milli-Darcy) was established for each geological unit using...
core measurements. Effective porosity was calculated from 8 Bécancour well logs using the method of Doveton (1986). Effective porosity was compared to porosity cutoffs to determine net pays of each geological unit. The net pay is the total thickness of a unit with sufficient porosity (and permeability) to allow the circulation of fluids. Lateral extents of net thicknesses were determined from cross-sections of effective porosity and raw well logs (neutron porosity NPOR, density porosity NPHZ and resistivity from deep laterolog LLD) (Konstantinovskaya et al., 2011).

3. SITE GEOLOGY

Konstantinovskaya et al. (2010) provide details about the geology of the study area, which is briefly summarized here. The sedimentary succession of the St. Lawrence platform was formed during Cambrian and Ordovician times in a tectonically stable zone (Globensky, 1987). In the Bécancour area, stratigraphic units are compartmentalized at depth into two distinct blocks by the Yamaska regional normal fault trending SW-NE (N~60°E–~45°SE). Unit thicknesses increase from the NW to SE across the Yamaska fault (Fig. 3). The structural map of the Grenville basement surface in the Bécancour area in TWT is shown in Fig. 2.

The simplified stratigraphy of units is presented in Fig. 4. The average unit thickness is summarized in Tab. 4 of Section 7. The deep saline aquifers are found at depth between 800 and 2400 m, in sandstone, dolostone and limestone reservoirs. The Potsdam Group sitting on the Precambrian Grenville basement comprises the Covey Hill (conglomerates and sandstones) and Cairnside (quartzose sandstone) Formations. The Beekmantown Group consists of the Theresa (dolomitic sandstone) and Beauharnois (dolostones) Formations. The Chazy and Black River Groups made up mainly of dolostones and fossiliferous limestones, and minor calcareous sandstones are overlain by the limestones of the Trenton Group. The overlying seals (caprock) consist of at least 800 m thick shales and siltstones of the Lorraine Group and the Utica Shales. These caprocks are overlain by the molassic shales of the Queenston Group.

Mineral composition of the two caprocks is presented in Fig. 5. Clay is the dominant mineral for the Lorraine siltstones, and calcite for the Utica shales. Clays occupy 50% and 23% for the Lorraine siltstones and Utica shales, respectively. Clays consist of 65-85% illite, 10-25% chlorite and 5% kaolinite (Thériault, 2008). With such a clay-rich composition, the caprock permeability should be in the order of 1×10⁻⁴ mD (Basava-Reddi and Wildgust, 2011).

4. HYDROGEOLOGY

4.1 Formation pressure and artesian flow rate

Saline aquifers of the Bécancour region are saturated by extremely salted water. Different formation pressure regimes are observed in the Bécancour area. Fig. 6 presents hydrostatic pressure profiles for all units of the region. These pressure profiles are compared with calculated hydrostratic pressures based on different

![Figure 3 Lithostratigraphic units in the Bécancour area (Castonguay et al., 2010; seismic line M2002).](image)

![Figure 4 Simplified stratigraphic column of the sedimentary succession in the St. Lawrence Lowlands (modified from Bédard et al., 2010).](image)

![Figure 5 Mineral composition of caprock units in the St. Lawrence Lowlands (data in Konstantinovskaya et al., 2010).](image)
fluid densities ($\rho$) corresponding to freshwater as well as the minimum and maximum brine densities observed in the saline aquifers ($\rho_{\text{min}} = 1090 \text{ kg/m}^3$ and $\rho_{\text{max}} = 1191 \text{ kg/m}^3$, see Section 6). Different pressure gradients ($\Delta P$) with depth (kPa/m) are observed for different units or different areas. Caprock units have two distinct pressure gradients: siltstones of the Lorraine Group are underpressured with a $\Delta P$ of 9.7 kPa/m, whereas the Utica Shale is overpressured with a gradient of 14.7 kPa/m (BAPE, 2010). This overpressuring is due to high compaction and closely sequestrated fluids in pores of this very fine-grained rock. In saline aquifer units, the pressure gradient varies from 10.78 kPa/m to 12.17 kPa/m in the northeastern part of the region and to 15.60 kPa/m in the southwestern part, Fig. 7. The average value of $\Delta P$ for all units combined is estimated at 12.17 kPa/m. This points out that the site reservoirs are partially overpressured with varying intensities. Pressure gradients and levels of overpressure are coherent with in situ artesian flowing rates observed in brine-producing boreholes (Fig. 8), which were classified as non-flowing ($Q \approx 0$), variably flowing ($0 < Q < 10$) and highly flowing ($Q = 13 \text{ l/min}$).

Moreover, the evolution of pressure buildup curves in well tests A158 (southwestern reservoir) and A196 (northeastern reservoir) which did not increase with time indicates that these sub-reservoirs are closed.

Figure 6 Hydrostatic pressure profiles obtained from the DST analyses and their gradients in comparison with pressure gradients calculated from minimum and maximum formation water density. (Pressure gradient of Lorraine Group and Utica Shale are taken in BAPE) ((TVD: true vertical depth).

(Lavoie, 1979 and 1992). It can be concluded that the Bécancour reservoir is non-homogeneous at the regional scale and is divided into two SW and NE sub-reservoirs, distinguished by a transient zone identifiable from seismic profiles (Konstantinovskaya et al., 2011). No regional flow of formation fluids has been observed.

Figure 7 Pressure gradients plotted on the structure map of the Grenville top surface.

Figure 8 Artesian flow rate plotted on the contour map (TWT) of the Covey Hill Formation top.
4.2 Reservoir temperature

Temperature of the Bécancour saline aquifers increases with depth from the ground surface, which has an annually average temperature of 8 °C (Fig. 9). Minimum and maximum temperatures are 26.5 °C for the Trenton Group and 61 °C for the Covey Hill Formation. A geothermal gradient of 23.5 °C/km is estimated from DSTs and well log temperature data. Tab. 1 shows the temperature calculated at the formation top of the shallow reservoir block (Yamaska fault footwall) using the temperature gradient. The temperature needed to have supercritical CO$_2$ ($T_c > 31$ °C) is found in the sandstones of the Cairnside and Covey Hill Formations.

4.3 Formation salinity

Formation water salinities in the Bécancour reservoirs vary from saline to hyper-saline (60 g/l to 340 g/l). Salinities of different units from different boreholes are reported in Fig. 10. These salinities do not always increase with depths, as often reported for other saline aquifers. The arithmetic average salinity of groups/formations is presented in Fig. 11. Minimum and maximum salinities were observed for two formations of the same Potsdam group: 109 g/l in the Covey Hill and 242 g/l in the Cairnside. Sharp changes in salinity between different geological units are inferred to indicate an absence of vertical hydraulic communication and fluid exchanges between aquifers.

5. ROCK PETROPHYSICS

5.1 Porosity-permeability-density

Based on core analyses, statistics on porosity $n$ and horizontal permeability $k_h$ were obtained for each unit (Tran Ngoc et al., 2011). Normal and log-normal distributions were generally observed for porosity and permeability, respectively. Tab. 2 presents median values of porosity and permeability. While maximum porosity is 6.3% in the Covey Hill sandstone, the minimum is only 0.4% in the Theresa dolostone with a significant standard deviation of 3.45%.

![Figure 9 Temperature profiles in the Bécancour deep saline aquifers.](image)

![Figure 10 Salinities measured in different intervals of different Bécancour wells.](image)
The median permeability ranges from 0.06 mD (Theresa dolostone) to 0.25 mD (Covey Hill Formation). Thus, the Covey Hill Formation is the best regional porous medium which is also indirectly confirmed by its least grain density (Tab. 2). Macroscopically, fractures enhance permeability, as the permeability determined from DST data is generally 1 or 2 orders of magnitude higher than from core analyses.

Permeabilities for other orientations were also measured on full cores, i.e. vertical permeability $k_v$ and horizontal permeability $k_{h\text{max}}$ at 90° from the $k_{h\text{max}}$ orientation. Comparison of permeabilities measured along these orientations reveals anisotropy (Fig. 12). The permeability ratios are in the order of 10 to 100 for $k_{h\text{max}}/k_v$ and about 5 for $k_{h\text{max}}/k_{h90}$. This is indicative of a dominant horizontal hydraulic connectivity across all the sedimentary sequence of units.

The Bécancour saline aquifers can be considered as a porous medium rather than a fractured one, especially for the lower units. Fig. 13 shows the good correlation between permeability and porosity for different units. This relationship generally applies, except for some “off-trend” data with high permeability at low porosity. These points are inferred to be related to micro-fractures in limestone and dolostone units.

Table 2 Median values of petrophysical parameters: porosity $n$, maximum horizontal permeability $k_{h\text{max}}$, apparent density $\rho_a$ and grain density $\rho_s$ (*: from BAPE, 2010).

<table>
<thead>
<tr>
<th>Group/Formation</th>
<th>$n$ [%]</th>
<th>$k_{h\text{max}}$ [mD]</th>
<th>$\rho_a$ [kg/m³]</th>
<th>$\rho_s$ [kg/m³]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lorraine Gp.*</td>
<td>5</td>
<td>0.0004</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Utica Shales*</td>
<td>3.7</td>
<td>0.0003</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trenton Gp.</td>
<td>3.4</td>
<td>0.25</td>
<td>2690</td>
<td>2700</td>
</tr>
<tr>
<td>Beauharnois Fm.</td>
<td>1.0</td>
<td>0.09</td>
<td>2720</td>
<td>2740</td>
</tr>
<tr>
<td>Theresa Fm.</td>
<td>0.4</td>
<td>0.06</td>
<td>2710</td>
<td>2705</td>
</tr>
<tr>
<td>Cairnside Fm.</td>
<td>3.3</td>
<td>0.12</td>
<td>2580</td>
<td>2650</td>
</tr>
<tr>
<td>Covey Hill Fm.</td>
<td>6.3</td>
<td>0.25</td>
<td>2450</td>
<td>2630</td>
</tr>
</tbody>
</table>

5.2 Net pay

Porosity cutoffs were determined by using the central permeability and porosity relationships for different units. Based on these relations, a permeability cutoff of 0.1 mD was related to a corresponding value of porosity cutoff (Fig. 13). The cutoffs obtained are 6%, 4%, 4%, 3% and 2%, respectively, for Trenton, Beauharnois, Theresa, Cairnside and Covey Hill units.

Effective porosity was calculated from well logs and compared with porosity cutoffs to determine net pays of each geological unit. Fig. 14 presents the net pay of different units in different Bécancour boreholes (Konstantinovskaya et al., 2011).

Net pay of Trenton limestones and Beekmantown dolostones is inferior to 10 m, which is less than 15% of their gross thicknesses. This indicates the random
distribution of permeable intervals in these units. The greatest net pays are found in the Potsdam sandstones: 50 m for the Cairnside quartz sandstone (61% of unit thickness) and 188 m for the Covey Hill quartzofeldspathic sandstone (96% of unit thickness). So, the net pay increases with depth. It must be mentioned that effective porosity data for the Covey Hill is available only in a single well (A198).

Unit net pay porosity and permeability can be deduced by using their relationship in Fig. 13, which are reported in Tab. 4. Average net pay and net pay pore volume per surface (product of net pay and porosity, m³/m²) were also calculated (Tab. 4). The unit pore volume is greatest in the Covey Hill Formation at 12 m³/m² and it is only between 0.1 and 2 m³/m² in other units. The lateral continuity of net pay was evaluated using cross-sections of well logs (Konstantinovskaya et al., 2011). It could be concluded that the net pay of the Covey Hill saline aquifer are spatially extensive.

6. FLUID PROPERTIES OF BRINE AND CO₂

Fluid properties have a significant effect on simulation of multi-phase flow and transport. Therefore, density and viscosity of fluids must be as representative as possible. Here, density and dynamic viscosity of formation brine and supercritical CO₂ are predicted in the Bécancour pressure and temperature PT conditions, based on mean gradients of pressure ΔP (12.15 kPa/m) and temperature ΔT (23.5 °C/km).
6.1 Brine density and viscosity

Figs. 15 and 16 present estimated densities and viscosities of formation brines using the Batzle and Wang (1992) algorithm, considering the salinities of different units (Fig. 10). The estimated values agree very well with the measured ones. Average density and viscosity in different units are shown in Tab. 4. We note that minimum values of density $\rho_{\text{min}}$ (1091 kg/m$^3$) and viscosity $\mu_{\text{min}}$ (0.875 mPa·s) are found in the Covey Hill Formation, whereas maximum values are observed in the Cairnside Formation ($\rho_{\text{max}} = 1191$ kg/m$^3$, $\mu_{\text{max}} = 1.285$ mPa·s).

Brine density and viscosity were also calculated at formation tops in order to compare these values with the ones of the supercritical CO$_2$ (Fig. 17).

6.2 Supercritical CO$_2$ density and viscosity

Fig. 18 displays the density spectrum of predicted CO$_2$ states calculated using the formula of Span and Wagner (1996). Fig 18 also presents the CO$_2$ state at different depths corresponding to different formation tops of the two Bécancour reservoir blocks. The supercritical state of CO$_2$ ($T_c = 31.1$ °C and $P_c = 7.38$ MPa) is only present in the Covey Hill Formation of the shallow reservoir block (1145 m of TVD). The density values predicted at different formation tops between 797-806 kg/m$^3$ are shown in Fig. 19 in more details. The CO$_2$ dynamic viscosities predicted at different formation tops is also presented in Fig. 19. They range between 0.70-0.73 mPa·s.

Table 3 Average density ($\rho$) and dynamic viscosity ($\mu$) of the brine in different units of the Bécancour aquifers.

<table>
<thead>
<tr>
<th>Group/Formation</th>
<th>$\rho$ [kg/m$^3$]</th>
<th>$\mu$ [mPa·s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trenton Gp.</td>
<td>1126</td>
<td>1.248</td>
</tr>
<tr>
<td>Black River Gp.</td>
<td>1148</td>
<td>1.324</td>
</tr>
<tr>
<td>Chazy Gp.</td>
<td>1172</td>
<td>1.415</td>
</tr>
<tr>
<td>Beauharnois Fm.</td>
<td>1125</td>
<td>1.040</td>
</tr>
<tr>
<td>Theresa Fm.</td>
<td>1116</td>
<td>1.214</td>
</tr>
<tr>
<td>Cairnside Fm.</td>
<td>1191</td>
<td>1.285</td>
</tr>
<tr>
<td>Covey Hill Fm.</td>
<td>1091</td>
<td>0.875</td>
</tr>
</tbody>
</table>

7. DISCUSSIONS AND CONCLUSIONS

The characterization of Bécancour saline aquifers was carried out on the basis of a wide range of available data. The reservoirs can be hydraulically sub-divided into confined and isolated parts according to formation pressures and artesian flow rates. In fact, the southwestern sub-reservoir seems isolated, based on its extremely high salinity (280-340 g/l) in the Cairnside Formation compared to the average salinity of 242 g/l for all saline aquifers. Preferential horizontal hydraulic continuity within units is indicated not only directly by the permeability anisotropy, but also indirectly by sharp fluid salinity differences between aquifers. This tendency for dominant lateral flow, along with low regional caprock permeability, enable to maintain the injected CO$_2$ plume within to the aquifers and prevent its emergence at the soil surface.

Vertical profiles of hydrogeological and petrophysical properties were defined on the basis of data from boreholes located in both footwall and hanging wall of the Yamaska fault, which separate two blocks of saline aquifer units. The hydro-geo-thermo-chemo-petrophysical behaviors of the Bécancour reservoirs (except the isolated southwestern part in can
Table 4 Main hydrogeological and petrophysical characteristics of the deep saline aquifers in the Bécancour region (Fm. = Formation).

<table>
<thead>
<tr>
<th>Average parameters</th>
<th>Lorraine</th>
<th>Utica</th>
<th>Trenton</th>
<th>Beauharnois</th>
<th>Theresa</th>
<th>Cairnside</th>
<th>Covey Hill</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fm. thickness of shallow block [m]</td>
<td>670.6</td>
<td>31.5</td>
<td>177.5</td>
<td>52</td>
<td>55.5</td>
<td>104.6</td>
<td>197.5</td>
</tr>
<tr>
<td>Fm. thickness of deep block [m]</td>
<td>1155.7</td>
<td>140.6</td>
<td>264.2</td>
<td>100.7</td>
<td>97.0</td>
<td>85.2</td>
<td>na</td>
</tr>
<tr>
<td>Net pay [m]</td>
<td>3.1</td>
<td>1.9</td>
<td>6.6</td>
<td>4.8</td>
<td>4.8</td>
<td>3.7</td>
<td>6.0</td>
</tr>
<tr>
<td>Net pay porosity [%]</td>
<td>9.4</td>
<td>5.5</td>
<td>4.8</td>
<td>3.7</td>
<td>6.0</td>
<td>3.7</td>
<td>6.0</td>
</tr>
<tr>
<td>Net pay permeability [mD]</td>
<td>0.20</td>
<td>0.23</td>
<td>0.15</td>
<td>0.13</td>
<td>0.28</td>
<td>0.15</td>
<td>0.13</td>
</tr>
<tr>
<td>Net pay fluid volume [m^3/m^2]</td>
<td>0.44</td>
<td>0.41</td>
<td>0.37</td>
<td>0.37</td>
<td>0.52</td>
<td>1.92</td>
<td>11.6</td>
</tr>
<tr>
<td>Temperature gradient [°C/km]</td>
<td>23.5</td>
<td>23.5</td>
<td>23.5</td>
<td>23.5</td>
<td>23.5</td>
<td>23.5</td>
<td>23.5</td>
</tr>
<tr>
<td>Salinity [g/l]</td>
<td>174.8</td>
<td>140.0</td>
<td>156.7</td>
<td>241.8</td>
<td>108.5</td>
<td>241.8</td>
<td>108.5</td>
</tr>
</tbody>
</table>

Figure 18 CO2 density as a function of pressure and temperature under the Bécancour reservoir conditions. Symbols refer to CO2 density at formation tops in two reservoir blocks (detailed in Fig. 19).

Figure 19 CO2 density and viscosity calculated at different formation tops of two reservoir blocks: bold symbols-density; empty symbols-viscosity; rectangle-shallow block; triangle-deep block (Tr-Trenton Gp., Bh-Beauharnois Fm., Th-Theresa Fm., Ca-Cairnside Fm. and CH-Covey Hill Fm.).

Yamaska footwall), can be represented by these profiles. It can be assumed that the Yamaska fault acts as a fluid conduit in the two parts of the reservoir system having naturally the same behaviors. The lateral extent of net pays may be indirectly confirmed through the above mentioned profiles (Tran Ngoc et al., 2011).

Based on this characterization, dimensionless numbers controlling the processes of fluid displacement can be estimated (in Espinoza et al., 2011). For instance, the $R$ and $M$ numbers being the density and viscosity ratios between the formation brine and supercritical CO2 are calculated at about of 1.4 and 15, respectively, for all units. Such values imply that both effects of gravity override and viscous/capillary fingering are to be expected (Nordbotten et al., 2005).

The characterization carried out indicates that the geological system of the Bécancour area is appropriate to store CO2 relative to technical criteria (hydrogeological and petrophysical properties of saline aquifers, seal caprock, geothermal gradient, tectonic stability) as well as economic criteria (reservoir depth/size, close to CO2 emitters and infrastructures).

The main hydrogeological and petrophysical characteristics of different aquifer units are summarized in Tab. 4. Among them, the Covey Hill quartzofeldspathic sandstone aquifer is the best suited unit for CO2 storage: largest injectable pore volume; highest hydraulic conductivity (assuring a good injectivity); best CO2 dissolution in brine due to the smallest salinity.

The Bécancour reservoir can be divided into numerous potential storage sites according to different depth intervals and hydro-geo-petrophysical bodies. The northeastern site appears a priori as the best choice for a pilot injection test. In the next steps of the assessment of the CCS potential of the Bécancour area, the CO2 storage capacity will be investigated for different sub-reservoirs. Numerical simulations of the CO2 plume spread in a selected site will also be done. To do so, laboratory experiments of sandstone cores are going to be conducted in order to obtain the needed hydrodynamic parameters. A proven numerical simulator applicable to the simulation of CO2 injection in saline aquifers will be used.

8. ACKNOWLEDGEMENT

This study was carried out under the Québec research chair on CO2 geological sequestration, financed by Ministère du Développement durable, de l’Environnement et des Parcs du Québec. The authors appreciate a close collaboration with the industrial partner Junex Inc.
9. REFERENCES


