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Feasibility of Injecting Large Volumes of CO_2 into Aquifers

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Abstract

Although it is recognized that deep aquifers offer a very large potential storage capacity for CO_2 sequestration it is not clear how to fill the storage with a large volume of CO_2 in a relatively short period of time. The typical benchmark for the rate of CO_2 injection is 1 Mt/year when studying storage performance. This rate is very low compare to the scale necessary for the storage technology to play a significant role in managing global emissions. In this study we perform numerical simulations of a large volume of injection, 20 Mt/year during 50 years of continuous injection resulting in a total sequestration of 1 Gt CO_2. A sensitivity analysis of the results (plume area and CO_2 storage capacity) is presented within the range of aquifer parameters: thickness (50-100 m); permeability (25-100 mD); rock compressibility (from 9×10^{-10} to 2×10^{-9} (1/Pa)) as well as different injection arrangements. The implementation of this study to a particular case of injection of 1 Gt total over 50 years into the Nisku aquifer located in Wabamun Lake Area, Alberta, Canada [1] is presented. In this area, large CO_2 emitters including four coal-fired power plants with emission between 3 to 6 Mt/year each are present. The Nisku aquifer is believed to be a suitable choice for future sequestration projects. In this case study a few injection scenarios (number of wells and their placement, which control the ability to inject without exceeding the aquifer's fracture pressure) are presented. The evolution of plume size and pressure field in the aquifer for these scenarios is shown. As opposed to the generic sensitivity study, the case study includes the heterogeneity of the aquifer and its dip angle. Both generic and Nisku studies have shown that the capacity of the reservoir in the case of large injection volumes should be evaluated not by available pore volume, but by ability to inject some amount without exceeding fracture pressure of formation.

Keywords: Large CO_2 injection; Aquifer; Storage capacity; Numerical simulation

1. Introduction

The main contributor of carbon to carbon dioxide emissions to the Earth's atmosphere is the burning of fossil fuels, which results in the emission of more than 23.5 Gt CO_2/year (2000 global emission data [2]). Underground storage of CO_2 is a well known method for managing and reducing carbon dioxide concentration in the atmosphere. However, for CO_2 storage to have a noticeable impact on atmospheric CO_2 levels it should be carried out on a very large scale.

Although aquifers offer a huge storage potential for CO_2 sequestration, the implementation of large volume injection to fill this capacity seems to be very complex. In scientific investigations by van der Meer [3] it was recognized that in low permeability formations or compartmentalized reservoirs the CO_2 injection will result in an increase in pore pressure. This increase in pore pressure can limit the ability to inject CO_2 into the subsurface, because overpressure-associated geomechanical damage needs to be avoided. In this case, the storage capacity mainly depends on pore and brine compressibilities that provide extended pore space availability, and on the maximum pressure buildup that the formation can sustain. Presented here is the quantitative investigation of a large volume CO_2 injection and its potential barriers. This work covers two general topics: (i) a generic study in which a homogenous, infinite acting but closed reservoir is used to determine the minimum number of wells and their spatial distance to achieve total injection of 20 Mt CO_2/year. Then, a sensitivity analysis of basic reservoir parameters

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and their effect on the final amount of stored gas is performed. (ii) The simulation results for an industrial scale project, namely the Wabamun Area CO_2 Sequestration Project (WASP) in Canada which is currently in the study stage is presented. This section investigates both the required number of wells for homogenous properties (corresponding to the lowest and highest values within an acceptable range) and the amount of stored carbon dioxide. Thereafter, the effect of heterogeneity of the Nisku aquifer relative to the evolution of plume size and pressure field is presented. This study concludes with a brief discussion of the remedial methods to deal with the issue of over-pressurizing the field of injection.

2. Generic study

Sufficiently large volumes of CO_2 can be injected into an aquifer if two conditions exist: An extensive aquifer with favourable properties (i.e. thickness, permeability and etc.) and the capacity to drill many adequately spaced injection wells. The aim of large volume injection also can be achieved if the injection rates are low, which may require a very long injection period. From a practical point of view it would be very important to know if it is possible to inject the volume within a relatively small area of injection and within a relatively short period of time; This section explores the required number of injection wells to reach a target injection rate of 20 Mt CO_2 /year with the constraint of maintaining the minimum distance between these wells and not exceeding 90% of the fracture pressure during the injection period.

For this generic study, a square (200 km × 200 km) simulation domain with different heights was chosen to represent an aquifer. By setting the model to these dimensions, the aquifer behaves as though it is infinite acting even though the target volume of CO_2 is injected. The top of the formation is located at a depth of 1500m below the ground surface. The properties of the reservoir were chosen similar to those used in the Berkeley Laboratory intercomparison study [4]. The aquifer is considered to be homogenous, isotropic, and isothermal with thickness of 100 m and permeability of 1.0×10^{-13} m^2 (100 mD), porosity of 12%, and rock compressibility of 4.5×10^{-10} (1/Pa) and fracture pressure equal to 30,000 kPa. In all runs, the initial conditions include temperature of 45 °C, pressure of 12000 kPa, salinity of 15% of NaCl by weight, brine saturation of 1, and gas saturation of 0.

This study employs CMG's commercial "black oil" simulator, IMEX. The required PVT data were produced based on an accurate fluid model offered by Hassanzadeh et al. [5]. In this fluid model the brine compressibility is taken into account in terms of density variation with fluid pressure.

Each numerical model consists of 61740 (42×42×35) fundamental grid blocks. These fundamental grid blocks have equal lateral size in all layers. However, generally the gas injection process is a bouncy dominant flow and the gas tends to move upward and occupy the uppermost part of the reservoir. Therefore, for a more accurate evaluation of the plume extension a top-down and exponentially increasing function was used to construct the grid size in the vertical direction starting with an 8 cm layer at the top.

Using reservoir simulation, Ghomian et al. [6] concluded that large simulation models require local grid refinement around injection wells to generate reliable results. Ennis-King et al. [7] also mentioned that use of coarse grids would lead to overestimation of dissolution rate during the injection period and hence underestimate the plume extension and size. Therefore, the local grid blocks are refined horizontally radiating away from injection wells to a distance of about 130 meters. Beyond this distance grid size gradually increases.

All simulation runs involve continuous injection for 50 years with no brine production. Bottom hole injection pressure is monitored and constrained to less than 90% of fracture pressure over the entire injection period. These parameters define a maximum CO_2 storage capacity over a period of 50 years.

2.1. Results

Figure 1 shows the model configuration for different numbers of vertical injector wells, starting with 1 and ending with 25. All wells are perforated from the top to the bottom of reservoir. The number of wells (n) was chosen to allow the use of an element of symmetry and hence reduce the total number of grids by a factor of four. The distances between the wells in both x and y directions are the same and equal to λ. Although the total injection rate is different for each case, the flow rates of individual wells are the same for each run and equal to the total rate divided by the number of wells.

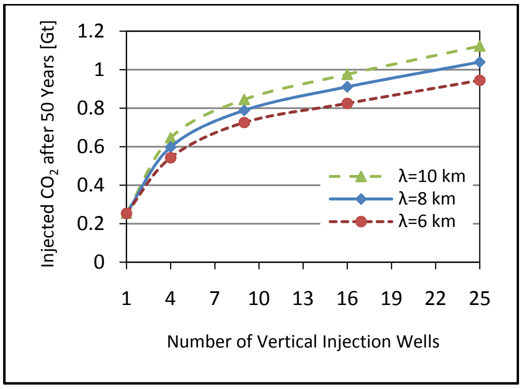
Figure 1: Configuration of injection wells and element of symmetry (salmon area)

The choice of either an injection pressure or a flow rate constraint could be made for each run. If the pressure constraint is chosen to operate the wells then the maximum injectivity is obtained by setting the injection pressure equal to 90% fracture pressure. On the other hand, if the flowrate constraint is chosen then a constant flowrate is applied for each run such that the maximum bottom-hole pressure does not exceed the sustainable pressure.

For a definite injection period, the simulation results (not presented here) indicated that for pressure constrained wells the achievable storage capacity is 35% to 65% of flowrate constrained well, depending on the number of wells. For example in the case of λ= 8 km and n=16, after 50 years, for a pressure constraint scenario the injected CO_2 is only 0.344 Gt while for a flowrate constraint is 0.867 Gt. This represents a significant difference. Therefore, all simulation runs make us of flowrate constraints for wells.

Figure 2 (left) shows the storage capacity considering the number of vertical wells and the distance between them. Note that the injection rate for each well was regulated such that the maximum bottom-hole pressure, which is always associated with the well near the center, reached to 27,000 kPa which is equal to 90% fracture pressure.

As this figure indicates, the required number of wells to achieve the target volume is 25 which are 8 km apart from each other. For practical prospective it may be more feasible to use smaller or larger amount of wells, covering a little bit larger or smaller area. Extrapolating the green and red curves we can roughly estimate the number of wells required. For example 18 wells which are 10 km apart or 28 wells which are 6 km apart will achieve the target (although in these cases the placement will be not symmetrical and particular simulations have to be performed). With respect to area of injection there would be no preferences between these three choices. For sensitivity analysis the blue curve in Figure 2, which corresponds to 25 wells which are 8 km apart will be used as a base case and all other data are compared against it. This case covers an area of 1024 km^2 (32km× 32km) km^2, which is a considerably large area. As the number of wells increases the injection rate of each well decreases to compensate for the excess pressure build up associated with new wells that affect the pressure response of the central well. Hence, the initial steep slope of the graphs (from 1 well to 4 wells) quickly approaches a constant slope.



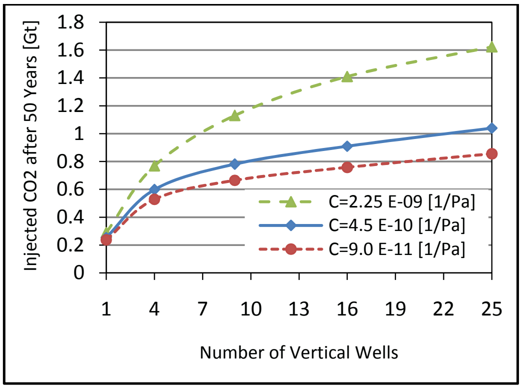


Figure 2: Variation of injected CO_2 versus number of wells and distance between them (left); Sensitivity to rock compressibility (right).

Additional simulations were conducted to investigate the effect of some aquifer properties such as rock compressibility, absolute permeability and thickness, on the amount of injected and stored CO_2 after 50 years. Since for the base case properties it was possible to inject the desired value of 1 Gt CO_2 over 50 years, the values of parameters were chosen closer to the expected aquifer properties. In all cases the rates of gas injection were adjusted such that at the end of injection period, the maximum bottom-hole pressure reaches the highest sustainable pressure.

Depending on the rock composition of the formations, the compressibility of the reservoirs varies widely [8-9]. Hence, for sensitivity study the value of compressibility was varied within one order of magnitude by multiplying and dividing the base case value by five, respectively. Figure 2 on the right shows the outcome. Higher values of compressibility cause significant differences on the results especially when the number of well increases. To explanation this behaviour, it should be mentioned that injecting a finite amount of fluid into a subsurface is accommodated by compressibility of the system components (brine, formation) and the increase in fluid pressure [10]. The first response is elevated by the more compressible component which is almost always the brine. For the range of pressures and temperatures usually encountered in reservoir the brine compressibility is in the order of 10^{-9} (1/Pa). When a higher value is assigned to rock compressibility, the bulk of the reservoir and its fluid gain the same order of magnitude and therefore act simultaneously in accommodating the exerted stress. Due to this fact, the slope of the curve also increases considerably and with fewer wells higher storage is accomplished. In contrast, when the compressibility is decreased, the main responsibility of pressure handling is again delivered to the brine and therefore in comparison with the base case no dramatic change will occur.

The permeability of the formation controls both the uniformity of the pressure distribution over the system volume and the propagation velocity of the pressure pulse away from the injection site. According to the diffusivity equation, pressure will diffuse faster in formations with higher permeability or lower compressibility. Although it is quite possible to find localized regions with high absolute permeability within an aquifer (which are usually allocated to injection sites), generally the average permeability of the formation may be low. Figure 3 on left depicts the results of simulations for different values of permeability. As the permeability reduces by half, the amount of stored gas nearly decreases by half. By reducing permeability the initial steep slope of the curves decreases which shows increasing the number of well is not much beneficial in low permeable formations and to reach the target value, many wells should be drilled.

The last parameter considered was the thickness of the formation. Reducing the thickness by 50% of the initial value has almost the same effect of reducing the absolute permeability by half as would be anticipated). The graph on the right hand side of the Figure 3 indicates that for thinner reservoirs, more wells should be placed in the injection zone or other methods of increasing injectivity should be considered.

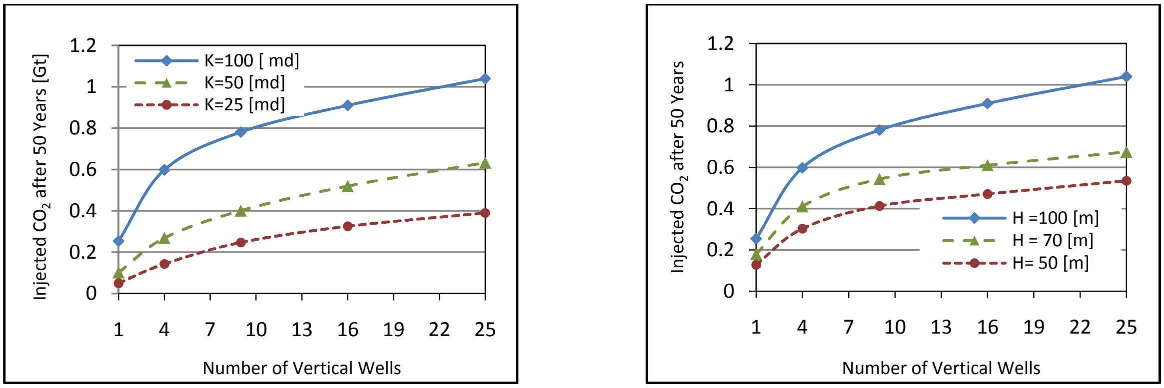


Figure 3: Effect of absolute permeability (left) and formation thickness (right) on storage capacity

3. Case study- Nisku Aquifer

A considerable number of CO_2 emitters are located in the central region of Alberta, Canada, including four coal-fired power plants in the Wabamun Lake area (Figure4-left) [11]. Together these plants emit approximately 30 Mt CO_2 per year. The Alberta Geological Survey has identified this area in the southwest of Edmonton as a potential storage site considering capacity, injectivity and confinement [11]. Moreover, since the large CO_2 emitters are located in the vicinity of area it would minimize the transportation cost which varies widely depending on the distance between source and sink. Different storage targets, based on stratigraphy and lithology, fluid composition, rock properties, geothermal, geomechanical and pressure regimes, are present in the study area. One of these targets, Nisku formation in the Devonian Winterburn Group, was selected for a more detailed investigation including modelling of the injection and spread of large volume of CO_2 in the subsurface [11].

The depth of the top of the Nisku formation ranges between 1600 m in northeast and gradually increases to 2150 m in the southeast. The Nisku was deposited at the edge of a carbonate shelf. From southeast to northwest, relatively pure platform carbonates change into interbedded limestone and shale of ramp and ultimately basin slope characteristics.

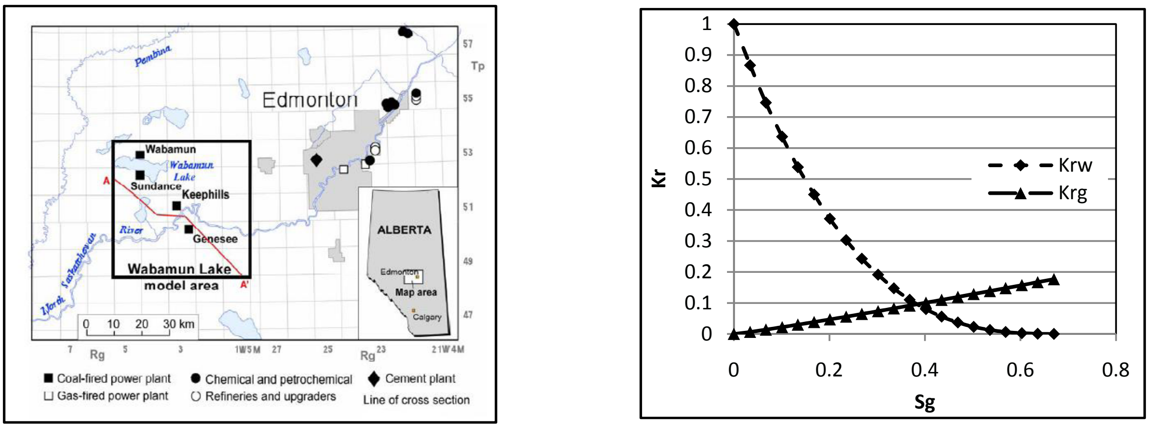


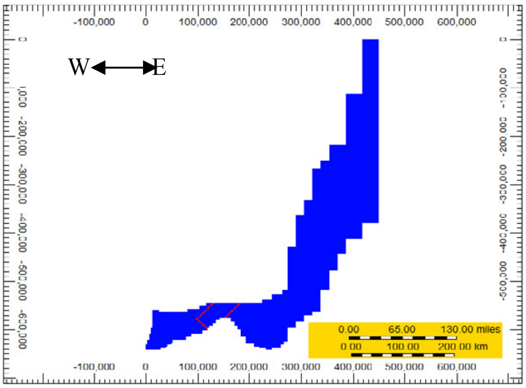
Figure 4: (left) Wabamun Lake study area which shows CO_2 emitters [11]; (right) Characteristic relative permeability curve of Nisku

The salinity of the formation water is equivalent to 190,000 mg of sodium chloride/L. The temperature of the formation is equal to 60 *°C* and at these conditions the water viscosity is equal to 0.84 cp. The net thickness of the aquifer is considered equal to 70 m and pressure at aquifer top is 16 MPa. All above data are taken from [1] and used for preliminary study of capacity and plume size. The characteristic relative permeability values of the Nisku carbonate which has been measured at in-situ conditions of pressure, temperature and brine salinity is shown on the right side of Figure 4 [12]. According to this curve, at residual water saturation, 0.3, the gas relative permeability is only 0.18 which is a considerably a small value and can significantly influence the injectivity of the gas injection well.

In the following section, the simulation results for CO_2 injection into the Nisku Formation will be presented. First, a homogenous model is considered to investigate the performance of a semi-infinite formation on injectivity. Then a heterogeneous model is presented with realistic permeability and porosity fields in order to demonstrate the effect of heterogeneity and reservoir dip angle on the evolution of a CO_2 plume and its associated impact on reservoir pressure.

3.1. Reservoir modelling- Homogenous model

Figure 5 (left) shows the top view of the Nisku formation. The region covers an area of about 450 km × 640 km while the bounded area by the red line shows the focus injection area. The majority of core and log data are related to available wells in this area and the injection site will be confined within this boundary. The area of this focus region is approximately 1500 km^2. The thickness of the numerical model is 70 m. 30 layers with variable thickness are used to create a 3D model. The fracture pressure at the top of the formation is 42 MPa and the maximum allowable injection pressure (bottom-hole pressure) was set at 40 MPa. Similar to the generic study, the injection period is 50 years. The core analysis data indicate the average absolute horizontal permeability is in the range of 30 to 90 mD which is considered to be a moderate permeability. The log and core porosity measurements indicate values between 8% and 12% which is subject to significant uncertainty. The Nisku is a carbonate formation and available core plugs confirms the existence of vugs in the formation which significantly influence the rock compressibility of the aquifer. It is expected that the compressibility can increase one order of magnitude from the base case which is equal to 1.45×10^{-10} (1/Pa). Therefore, for the base case the following aquifer properties have been used: porosity is 10%, horizontal permeability is 30 mD and rock compressibility is 1.45×10^{-10} (1/Pa). We started with one injector then simulated 5, 10 and 20 injectors.



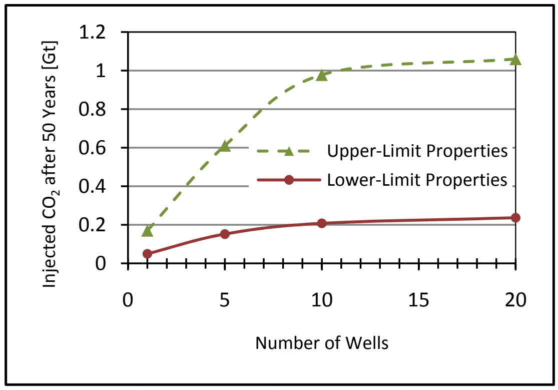


Figure 5: Top view of the Nisku formation in the Wabamun Lake area (left), Variation of Nisku capacity with respect to number of wells and formation properties (right)

Starting with one well, the maximum achievable rate was determined to be as high as 1.1 Mt CO_2/year, which is equivalent to 0.055 Gt after 50 years. This flowrate causes the bottom-hole pressure to touch the 40 MPa at the end of injection period. Next, five wells are placed in the zone. The corresponding flowrate for each well reduces to 0.625 Mt/year per well with cumulative injection of 0.15 Gt. Increasing the number of wells to ten, brings the flowrate to 0.418 Mt/year per well with total injected CO_2 of 0.209 Gt. Finally, these values for 20 wells are equal to 0.238 Mt/year and 0.238 Gt, respectively. These results are shown in Figure 5 (right), red curve corresponding to the base case properties. The effects of different properties were considered in the generic study section and are not considered here again. Instead, we estimated at what reservoir properties we can achieve the target of 1 Gt. The green curve on Figure 5 (right) presents the injection capacity of the focus area with the following aquifer properties: porosity of 20%, horizontal permeability of 90 mD and rock compressibility of 1.45×10^{-9} (1/Pa). Although these values cause significant difference in the outcome, the limitation in injectivity improvement for more than 10 wells still exists. It could not be claimed that these values are the maximum injectivity and storage of the formation because no optimization with respect to well positioning and flowrate was done.

Figure 6 presents the plume extension and pressure distribution after 50 years of injection using base case properties. For the case with one well the plume radius at the top layer is about 4.6 km which is consistent with the analytical solution radius [13]. It is noticeable that the size of "*pressure plume*" is much larger, is about 65 km, even for one well. In the cases of n number of injectors we can see n individual plumes for CO_2 saturation. As the number of wells increases the individual injector flowrate decreases and consequently the plume radius reduces. However, for pressure we can see a very strong interference between injectors, pressurising all area of injection. . However, pressure counters soon merge and thereafter a cumulative pressure disturbance dissipates radially from a central position which is the well position for one well model and is near the center of the focus area for the models.

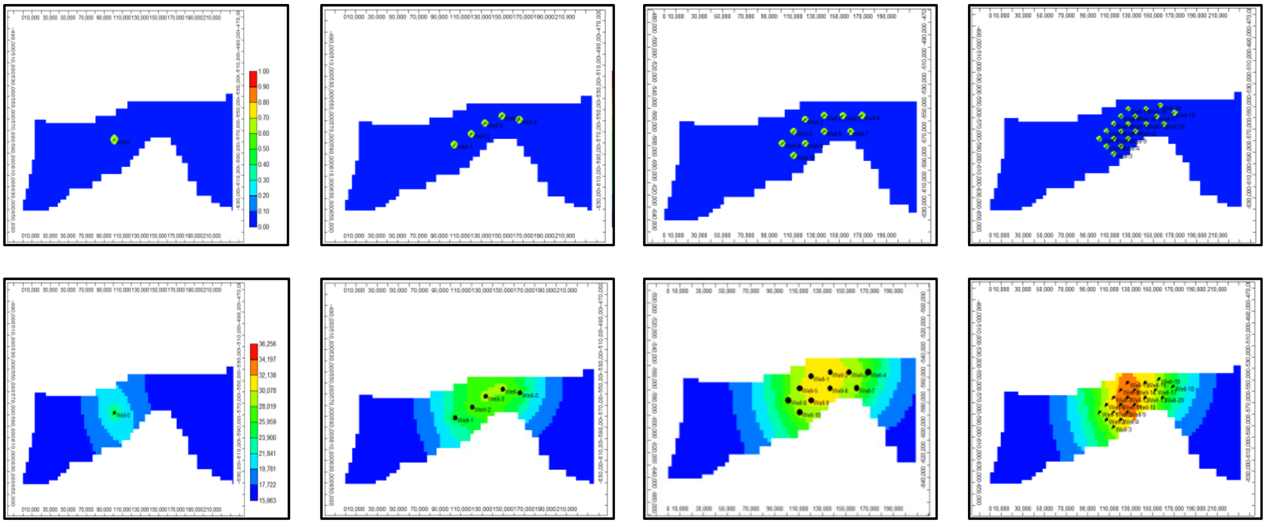


Figure 6: Plume extension (top row) and pressure radius of investigation (bottom row) after 50 years of injection for different number of wells in Nisku study area

3.2. Reservoir modelling- Real heterogeneous model

The initial heterogeneous model is based upon porosity and permeability data derived from core plugs for 11 wells within the WASP study area. Additionally, porosities calculated from 17 acoustic logs were used to better populate the static model. Data distribution is poor and spotty data is limited to the south eastern portion of the study area.

The geologic model incorporates 2,981,440 cell blocks with approximate lateral dimensions of 200 m in both the x and y directions. The vertical cell block dimension is variable with an average thickness of 3.8 m. The static modeling is being compiled using Schlumberger's Petrel subsurface modeling software. Products are then exported for simulation in the CMG IMEX black oil simulator.

In order to run the heterogeneous model successfully in a flow simulation the initial static grid must be upscaled. For this first iteration, a simple arithmetic average of cell properties was used during the upscaling process. Refined grids within the WASP study area and around the hypothetical injection wells (Figure 7) were made to improve model accuracy. It should be noted that accurate upscaling of flow properties from the geologic static model to the grid used for flow simulation is a complex and iterative process, especially in carbonate systems. As this phase of the study has just recently begun, the results presented here still reflect numerous uncertainties. The current flow simulation model includes 150,000 fundamental grids.

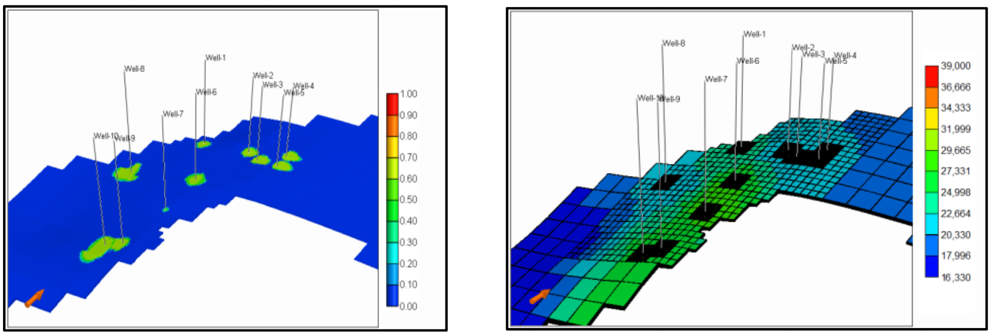


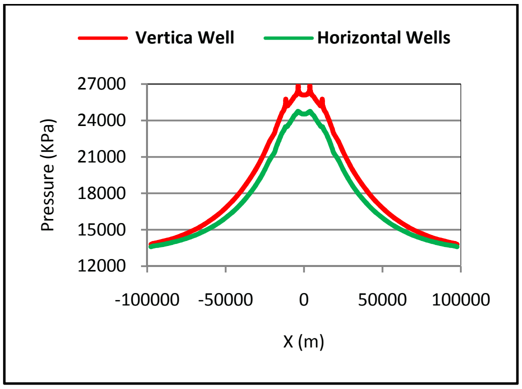
Figure 7: CO_2 plume extension (left) and pressure distribution (right) after 50 years for hetregenous Nisku model

Within the study area only a few spots with proper area offer higher permeability zones (in order of 100 mD) and large regions within the domain still have moderate (10-30 mD) to low (1-10 mD) permeability. Therefore, in contrast to the homogenous model, the wells are placed in high permeability zones to obtain higher injectivity. However, this will introduce the problem of short distances between wells which cause quicker pressure communication and reduces the injection capacity. The injectivity of the heterogeneous model for 10 wells is not considerably greater than the homogenous model with base case properties and presents at most a 22% increase in the total amount of stored CO_2 was observed. Note that, this is just a first estimation of the storage capacity of the heterogeneous model and a more sophisticated study regarding the geostatistical and geomechanical characterization of the formation is required.

4. Methods of increasing the capacity

In storage process the term "capacity" could have two meanings. The apparent capacity is the available and accessible pore volume of the aquifer. However, the injection capacity is the amount of CO_2 that can be injected realistically into the formation and is a strict function of the number of wells and the fracture pressure of the formation and the confining caprock [14]. As discussed earlier, for a restricted injection area such as Nisku study, increasing the number wells beyond a limit (which is controlled by formation properties and injection site area) has a minor effect on the injection capacity. The focus of this section is the investigation of the methods that lead to an increase in injection capacity of the aquifer.

The first method is using horizontal wells instead of vertical wells. For vertical wells, it is preferable to use fully penetrated wells over the whole thickness of the aquifer. To find the minimum length of the horizontal well, the effective radius of pressure disturbance around the vertical injection well, which is again a function of formation properties, should be determined. For vertical wells, as the injection begins the pressure around the wellbore increases rapidly and causes the development of locally narrow width pressure peak in vicinity of the well. The left graph in Figure 8 shows the spatial distribution of pressure along the dotted red line in frame 4 of Figure 1 for vertical well configuration after 50 years of injection. The x axis shows the distance with respect to the boundary of the simulation area. The figure clearly shows the peaks around the injectors that indicates an effective radius of about 1250 m. Application of horizontal wells with this length will diminish these peaks and increase the injectivity (consider the dotted green line in frame 4 of Figure 1 and the corresponding graph (green) in Figure 8). For the Nisku formation the length of the horizontal wells was equal to 3000 m.



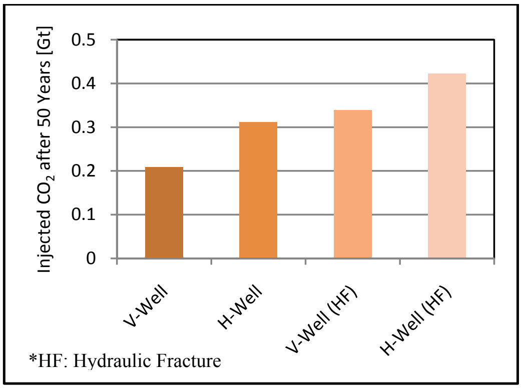


Figure 8: Comparison of bottom hole pressure of vertical and horizontal well configuration (left), Comparison of the effect of different well orientations and stimulation on the storage capacity of the model (right)

Application of stimulation techniques such as hydraulic fracturing and induced micro-seismicity can also improve injectivity. The technical feasibility of implementing these techniques requires careful geomechanical characterization of the formation. Vertical wells with hydraulic fracture of 400 m (half length) were modeled by constructing thin grid blocks in the E-W direction. A porosity of 15% and permeability of 1500 mD was assigned to these grid blocks to approximate a 400 m half-length fracture and associated damage zone. These properties were also used to construct of four 100 m half length of 4 staggered hydraulic fractures for horizontal wells. The column chart in Figure 8 shows the simulation results for 10 wells cases (located in Figure 6) in Nisku aquifer. One may conclude that using any stimulation technique can improve the injectivity. However, this result was not unexpected considering the fact that the limited area of the focus region causes quick pressure communication between the wells and hence reduces the injection rate of the wells. The effectiveness of the micro-seismicity method requires a comprehensive knowledge of the geomechanical features of the aquifer and is left for future studies. A final method of increasing CO_2 capacity in the Nisku aquifer would be to produce brine [15] from the formation to prevent the reservoir pressure from building up excessively near injection wells. This method involves transporting produced brine through surface pipelines to a location where brine can be disposed into another compatible formation or into a lower pressure region of the Nisku aquifer itself. Transporting brine long distances is both expensive and requires added environmental precautions. Furthermore, the presence of dissolved H_2S in the Nisku brine adds an element of risk to this option due to the toxicity of H_2S.

5. Summary and conclusion

This paper demonstrates that underground injection of substantial amounts of CO_2 may be a very difficult task. The injection capacity might be limited by injection of large volumes of gas within a relatively small area and within a relatively short period of time. Injection capacity may be much lower than estimated by available pore space on its own. The reservoir pressure during injection may exceed the fracture pressure very fast and injection should be stopped before the target amount is injected. Large volumes would require a multiple injection well design, but it was shown that increasing the number of injection wells has diminish returns. The sensitivity study provides an illustration of the degree to which each reservoir parameter influences CO_2 injectivity and capacity. Permeability and net thickness of the formation have a direct impact on injectivity, but rock compressibility manifests its effect when a larger number of injectors is used.

The Nisku aquifer in Wabamun area of Alberta is considered as a potential candidate for CCS. Although the entire aquifer provides a huge pore volume capacity, the injection site (the study area) covers an area which is approximately 1500 km2. Since the characterization of the formation is in progress, the main focus of this study was a homogenous model with properties representative of the average values in the study area. However, these average values are based only on a limited amount of data currently available from wells previously drilled and tested in the Nisku aquifer. Future wells, optimized for injectivity may prove to demonstrate higher permeabilities. The current results may be illustrative of only the lower range of parameters specific to CO_2 injectivity. The results, however, do indicate that increasing the number of wells in a semi-closed area (like the one in this study) is not an effective way to increase injection capacity. The effect of heterogeneity was considered by introducing a preliminary geostatistical model of the Nisku. Based on this preliminary geostatistical heterogeneous model no evidence of significant improvement in the final storage capacity of the area was observed.

Finally, various methods of increasing the contact area of the injectors including horizontal wells as well as stimulation techniques were studied. The application of all these methods led to minor improvements in results. The economic and engineering aspects of CO_2 injection were not considered in this work and are left as the subject of further studies.

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