Abstract

Based on experience gained from existing sequestration pilot projects and enhanced oil recovery practices, geologic storage is a technically viable means to significantly reduce anthropogenic emissions of CO2. During CO2 injection, increasing pore pressure and temperature reduction create geomechanical deformation of both the reservoir and surrounding rocks. One of the most important concerns with respect to the long term CO2 storage is that stress changes caused by injection could lead to formation fracturing or reactivation of fracture networks and fault movements which could potentially provide pathways for CO2 leakage through previously impermeable rocks.

The cumulative CO2 emission from power plants located in Wabamun lake area in central Alberta, Canada reaches 30 Mt/year. Nisku geological formation located in Wabamun lake area was chosen as storage target based on storage capacity, expected ease of injectivity, leakage risks and interference with current petroleum production in the area. In order to determine whether the post-injection stress changes affect the viability of this target formation to act as an effective storage unit, the geomechanical assessment model of the formation has been developed, which couples the flow model and geomechanical model covering all layers from the basement to the surface. This work was a part of a comprehensive feasibility study of large scale CO2 storage potential in the Wabamun area, called the Wabamun Area CO2 Sequestration Project (WASP). The model used rock mechanical properties, reservoir characterization and flow properties of the Nisku provided by extensive work in other teams of the WASP project. The present modeling work focused on evaluation of a single well injecting 1 Mt/year for 50 years, followed by simulation of 50 years of shut-in.

The pressure and stress variations were modeled during and after CO2 injection utilizing geomechanical software, GEOSIM, commercial code of Taurus Ltd. In order to increase the well injectivity, the case of allowing fracture initiation and propagation in Nisku was considered. The results show that injection above the fracture pressure will have the potential to increase the well injectivity (to at least 2 Mt/year) but also create the possibility of fracturing the caprock. The possible upward fracture propagation strongly depends on the caprock stress state and mechanical properties. However, the results of the simulation of vertical propagation have been obtained under the most unfavorable assumption of constant minimum stress gradient and are only preliminary.

Since injected CO2’s temperature is considerably lower than the formation temperature, thermal effects were incorporated into the models. Decreasing temperature due to CO2 injection will result in stress reduction and smaller surface deformations compared to the isothermal model. Thermal effects of cold CO2 injection will also reduce the fracture (injection) pressure and enhance the horizontal fracture propagation through Nisku.
CO₂ injection in the Nisku zone is not likely to cause any significant surface heave and is not likely to have any environmental impact associated with surface deformations. Surface deformation data can be used in conjunction with seismic measurements to validate mechanical properties of Nisku and overlying layers. It also can help to plan for the location of the instrumentation and surface monitoring. Given the best estimates of cohesion and friction angle, the probability of reaching shear failure in Nisku or in the caprock is low. However, the likelihood of fracturing due to thermal effects is high. The importance of modeling of thermal effects in CO₂ storage is the most important contribution. The results of this study are in agreement with our research on CO₂ storage in Ohio River Valley.

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Keywords: Geomechanical modeling, CO₂ storage, fracture propagation

1. Introduction

The annual emission from the large stationary power plants in central Alberta is in the order of 30 Mt/yr which includes four coal-fired power plants in the Wabamun Lake area, southwest of Edmonton with emissions between 3 to 6 Mt/year. Since most of the oil and gas reservoirs in the Wabamun lake area are still under production, they may not be available for CO₂ storage in the near future. Therefore storing CO₂ in saline aquifers in the area is the most likely short term solution in order to reduce CO₂ emission from local power plants. Increasing pore pressure and temperature reduction during CO₂ injection results in deformation of both the reservoir and surrounding rocks. A portion of injected CO₂ can escape the storage domain if the integrity of the seal rock is violated by geomechanical mechanisms such as fault reactivation, propagation of induced fractures or rock shear failure. In order to determine whether the stress state compromises the ability of the formation to act as an effective storage unit, a geomechanical assessment of the formation integrity must be carried out, by the means of coupled flow and geomechanical modeling. In recent decades there has been significant effort towards developing simulation techniques to model the aforementioned mechanisms for petroleum industry applications. The goal of this study is to further develop this simulation technology and modeling tools to model and understand the mechanisms and physics of the geomechanical effects occurring during or after CO₂ injection. The specific purpose of this study is to investigate the geomechanical effects of CO₂ injection in the Nisku aquifer located in Wabamun Lake area. The study utilized GEOSIM, a fully coupled reservoir flow and geomechanical model [1]. In this paper, the post injection stress changes, displacement pattern, the possibility of increasing the well injectivity by injection at fracturing pressure, fracture propagation and the risk of fracturing the caprock are investigated. Finally the thermal effects of injection are incorporated in the geomechanical model and the cooling effects of injection on stresses, displacement and fracture propagation are studied. The results can be then used, in conjunction with other work done in the WASP feasibility study, to define the optimum injection scenario in terms of technical and economical feasibility of the WASP project. In particular, the injection at fracturing conditions (i.e., propagating dynamic fracture during injection) and the use of production wells are novel ideas for increasing the efficiency of CCS

2. Model geometry and geomechanical properties

The model geometry, reservoir characterization, and fluid properties were derived from the flow model built in reservoir simulation sub-task of the WASP study [11]. The porosity, horizontal and
vertical permeability of Nisku reservoir is considered as 10%, 30 md and 3 md respectively. Figure 1 shows the lithology and principal stress direction in the study area and the pressure distribution after 50 years of injection in the Nisku aquifer. The yellow dotted boundary line shown on this diagram illustrates the edges of the porous and permeable regions of the Nisku aquifer. The red box is the WASP project region. Since the pressure plume has not extended to the north side of the aquifer and because the geomechanical effects strongly depend on pressure variation, the north side of the aquifer is not included in this study. The geomechanical model, which only included the area inside the red dashed rectangle (Figure 1 (right)), was superimposed on the updated flow model. The areal extent of the flow and geomechanical models is the same but the geo-model is extended in the vertical direction to model the caprock and the shallow layers up to the surface. The areal size of both models is 338100 x 119340 (m) and the vertical thickness of the flow and geo-model are 70 (m) and 1930 (m) respectively. The reservoir is represented by 4 layers, with the smallest layer at the top, in order to capture the CO$_2$ plume override. A detailed, flow-only CO$_2$ placement study [11] showed that even more layers would be required for high accuracy, but finer models were not possible at this stage due to very large computing requirements of the coupled model. Geomechanical properties were available for the Nisku aquifer and the 3 overlying geological layers up to 1200 m depth. The caprock layer immediately above Nisku was divided into 2 model layers The remaining shallow overburden was modeled as one layer. The flow and geomechanical models then consist of 97 x 62 x 4 and 97 x 62 x 10 grid blocks, respectively. For modeling fracture propagation in Section 5, the thick carbonate layer above the caprock was further refined into 5 layers. The initial distribution of stresses was assumed to have constant gradients for the $S_{\text{Hmax}}$ (maximum horizontal stress), $S_{\text{hmin}}$ (minimum horizontal stress) and $S_{\text{v}}$ (vertical stress) [2]. The pore pressure gradient was considered equal to fresh water hydrostatic gradient. The maximum stress gradient was approximated to be in the range of 20-23 kPa/m. Due to normal faulting regime in Wabamun lake area, the maximum stress was assumed to be equal to the vertical stress. The direction of $S_{\text{hmin}}$ was approximately 145°, in a general southeast-northwest direction [3]. Because of the lack of more detailed stress-strain data, linear elasticity was assumed in the simulation. The mechanical properties were kept constant for each geological layer and layers with similar geological and geomechanical properties were lumped together. Therefore more spatial refinement is required in order to accurately represent the local rock properties and stress profile at particular well locations.

3. Results – isothermal injection without consideration of fracturing

The first set of results presented is for the case when the injection pressure is limited by assumed fracturing pressure of 40 MPa and fracture propagation is not considered. The well in those models was injecting at a rate of 1 Mton/yr (=51,362 MScf/day). All the results in this Section are obtained using isothermal modeling (i.e., the injected CO$_2$ temperature equal to reservoir temperature). In Section 6 we will examine the effect of injecting cooler CO$_2$ which will dramatically affect the fracturing pressure. As expected, after CO$_2$ has been injected in the Nisku aquifer, the formation will undergo deformations in all directions in order to place the injected volume. As one travels from reservoir’s topmost layer to the surface the value of the vertical displacement will decrease to ~2 mm. The extent of this decay in deformation depends on the mechanical properties of the overburden. The vertical displacement at the surface after 50 years of injection is shown in Figure 2. The magnitudes of displacements after this long-time injection are small and on the order of 1 millimeter. The displacements are an important result of the simulation because they can be matched to the uplift, tiltmeter and other monitoring data, and also can be used for planning the location of instrumentation and improving the quality of input rock mechanical properties.
The measured magnitude of the deformations (vertical uplift) can be used to confirm system compressibility in the injection zone (important for injectivity) and possibly mechanical properties of the overburden.

5. Results – isothermal injection considering formation fracturing

Allowing dynamic fracturing (by removing the bottomhole pressure restriction) has the potential for increasing the well injectivity. However it is important to model (and monitor in the actual operation) the fracture growth for several reasons: 1) to make sure fracture would not propagate through the caprock to the extent that it would create a loss of containment (i.e., connect to other permeable zone), (2) to use the information on fracture length to design correctly the well pattern, and (3) to be able to control the injection rates to avoid excessive fracture lengths. The results presented here are the first preliminary work in this area, which demonstrates the concepts of the modeling and feasibility of the process. More detailed work would be required to arrive at reliable fracture growth predictions that could be used to design the injection scheme. Such work should be supported by field pilot data and lab geomechanical data. It is important to model the fracture growth both laterally and vertically through the caprock. To do that, the caprock layers were included also in the flow model (with small porosity and permeability) to track the possible fracture growth through them. Then the fracture was allowed to propagate both in the Nisku zone and in the layers above, using the numerical techniques described below. Since the minimum stress is in the y direction, the induced fracture plan would be perpendicular to this direction (vertical fracture). In order to model the dynamic fracture propagation, a transmissibility multiplier technique is incorporated in the model, which essentially accounts for the fluid flow transmissibility through the fracture by a transmissibility multiplier function, specified as a table. The function is calculated from an estimate of fracture opening of a Griffith fracture model [5], and it can be incorporated in the model both as a function of pressure or effective minimum stress. In order to calculate it, a fracture half height of 35 m (equal to half-height of the Nisku aquifer) is considered and the rest of the data are taken from the...
mechanical properties of the injection zone. If the fracture height varies during simulation, the actual multipliers would also vary, but this approximation is still valid.

![Figure 2: Vertical Displacement (meter) at ground surface after 50 years of injection at 1Mton/yr below fracture pressure](image)

### 5.1. Results of injection at 2 Mton/yr allowing fracture propagation

After 50 years of CO₂ injection above the fracture pressure, a total volume of 100 Mt is injected into Nisku in 50 years. Figure 3 shows the gas saturation at well block cross section after 50 years of injection. Since there is no stress contrast in the caprock compared to the reservoir zone, there is no effective barrier to height growth. Once the pressure develops in the caprock layer resulting in a negative minimum effective stress, fracture propagation starts in that layer. The fracture half-length and full height for the isothermal model after 30 years of injection reaches 7.5 m and 43 m, and after 50 years of injection is approximately 27.5 m and 25 m, respectively. The lateral fracture growth increases in the late stages due to overall pressurization of the Nisku aquifer, but the CO₂ plume extends well beyond the fracture. However, fracture does not propagate upward past the first caprock shale layer, and more resolution is needed to estimate the fracture height growth dynamics more accurately. It is important to realize that there are other fracture mechanisms which are not considered in this study and might change the fracture propagation through caprock [6]-[8].

### 6. Thermal effects

Since cold CO₂ (at approximately 30 deg C) will likely be injected into the relatively hot Nisku formation (at 60 deg C), thermal effects of injection should be included in the model. Cooling of the formation reduces the total stresses and therefore lowers the fracture propagation pressure. This reduces the pressure differential available for injection, and therefore injectivity. In the case of injection at fracturing conditions, the fracture propagation pressure will decrease and, if the same injection rate is used, this will accelerate fracture propagation. The isothermal model was extended to include thermal effects of injection. The thermal data used are listed in table 3 and was estimated from literature [9]-[10].

<table>
<thead>
<tr>
<th>Table 1: Thermal properties of fluid and rock</th>
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<tr>
<td>Rock</td>
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<tr>
<td>Thermal Expansion Coefficient (1/K)</td>
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<td>Heat Capacity(KJ/Kg K)</td>
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<td>Thermal Conductivity(KJ/m C Day)</td>
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6.1. Thermal effects for injection below fracturing pressure

We first consider the case of injection below fracturing pressure, described previously. Figure 4 (left) shows the stress and pressure history of both the thermal and isothermal model. The reason for this pressure difference is that in the thermal model the injection is modeled at 30 Deg C as opposed to 60 Deg C in the isothermal model. Since the total injected mass of CO$_2$ is the same for both models and because CO$_2$ will occupy less volume at 30 Deg C, the pressure will be slightly smaller in the thermal model. The reduction of stresses in the thermal model is related to the inclusion of temperature effects in the calculation of stresses. After injection stops and temperature rises, stresses will increase again. It should be noted that in the thermal model, the minimum horizontal stress falls below injection pressure at early injection time and creates negative effective stress and therefore would initiate fracture in the formation. It is important to realize that the stress magnitudes after fracturing are not valid in this figure because fracture propagation is not allowed in this model. Figure 4 (right) shows the surface displacement for thermal and isothermal model. Once the thermal effects in Nisku have influenced a relatively large area around the wellbore, the reduction in Nisku’s stress will be transferred to the surface and the surface displacement for the thermal model will fall below that of the isothermal model.

6.2. Thermal effects on dynamic fracturing

Thermal effects of injection on the dynamic fracture can be seen by studying the fracture length and vertical growth and fracture propagation pressure. In order to study the thermal effects on fracture length and height, the previously described fracture model was extended to include the thermal effects of injection. Figure 5 (left) shows the gas saturation at wellbore cross section. This Figure has the same scale as Figure 3 (right). The dynamics of the fracture propagation is complex as it depends on both poroelastic and thermal effects on stresses. In particular, the vertical growth in the thermal case is different compared to the isothermal one. The fracture half-length and height in the thermal case at 30 years are 267.5 m and 112 m, respectively, which is larger compared to the isothermal case.
After 50 years of injection, the half-length grows to 367.5 but the fracture height remains constant. As shown in Figure 5 (left), the gas saturation zone is also larger in comparison to the isothermal case shown in Fig. 3 (right). Due to the dominance of thermal effects, the fracture dimensions are relatively independent of caprock permeability. Figure 5 (right) shows the fracture propagation pressure for the thermal and isothermal model. As expected, since the thermal effects cause reduction in the total stress, the fracture propagates at much lower pressure in the presence of thermal effects.

The reduced injection pressure means smaller pressure gradient into the formation and therefore reduced injectivity, which must be compensated for by faster fracture growth. This is an important result, because the injection temperature of CO$_2$ can be controlled at the surface and it can be therefore one of the optimization variables. We note that limited fracture growth into the caprock is not necessarily harmful. Only if the fracture would grow completely through the caprock, then it could serve as a fluid source for the shallower geological layers.
7. Conclusions

Injection in the Nisku aquifer (below or at fracture pressure) is not likely to cause any significant surface heave and is not likely to have any environmental impact associated with surface deformations. Surface deformation data can be used in conjunction with seismic measurements to solve an inverse problem for mechanical properties of Nisku and overlying layers. It also can help to plan for the location of the instrumentation and surface monitoring.

Injection above the fracture pressure will have the potential to increase the well injectivity but also the possibility of fracturing the caprock. The degree of vertical propagation will strongly depend on the caprock stress state and mechanical properties.

Thermal effects of cold CO$_2$ injection will reduce the fracture pressure and enhance the horizontal fracture propagation through caprock. However, the results of simulation of vertical propagation have been obtained under the most unfavorable assumption of constant minimum stress gradient and are only preliminary (and likely pessimistic).

References