Improving the Competitiveness of Geothermal Energy Exploitation through Integrated CO_2 Storage in the Western Canadian Sedimentary Basin

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ABSTRACT

With Canada's current commitment to reduce its carbon footprint, development of geothermal energy in the Western Canadian Sedimentary Basin (WCSB) is now a more attractive option. This is especially true in Alberta and Saskatchewan whose electrical grid has a high carbon intensity due to coal fired generation. However, geothermal energy continues to be confronted by investment barriers. To mitigate exploration risk and boost investment in geothermal energy development, different versions of simultaneous carbon storage in geothermal systems (i.e. underground porous rocks) are being investigated. In this context, the WCSB also offers potential Giga-tonnes capacity for CO_2 storage through its relatively continuous high quality porous formations. It is these same formations that offer significant thermal potential for power and direct-use applications. Alberta No. 1, a conventional deep geothermal project with purpose drilled wells, is developing a geothermal power project in the WCSB, near Grande Prairie, Alberta.

Although there are different options to integrate geothermal energy exploitation and CO_2 storage, the success is primarily controlled by the availability and quality of pore volume of rock formations transected by the wellbore. To this end, the selection of geological structures (e.g. hot saline aquifers) must satisfy the minimum requirements of both the geothermal energy development and the CO_2 storage project.

In this study, we review the geological and reservoir conditions of underground structures in the WCSB, suitable for integrating CO_2 into geothermal projects. These include the analysis of structure type and continuity, reservoir depth, thickness of pore space, pore volume capacity, and petrophysical properties from available well logs and core data in the region. We look at a number of scenarios on how CO_2 storage and geothermal energy production may be feasibly integrated. Examples include the use of adjacent rock formations for both geothermal and CO_2 storage, or the use of same formation as in CO_2 Plume Geothermal, and multi-fluid geo-energy systems. Additionally, multiple well completions into separate formations, and re-purposing a wellbore that fails to meet commercial standards for geothermal development will be investigated.

Standalone geothermal power projects in Alberta require the sale of both heat and power, as well as offset carbon credits to be economic. This study aims to build on this issue and to suggest ways to maximize the competitiveness of such geothermal plants through CO_2 storage integration. The results of this study will be applicable to other sedimentary basins with similar conditions to the WCSB.

1. Introduction

Canada has committed to reducing its GHG emissions by 40% below 2005 levels by 2030. CO_2 storage has been identified as a technology that is capable of achieving reductions at the scale of megatonnes per year. Reducing emissions associated with power and heat production may also be achieved by using renewables sources of energy, such as geothermal energy production.

The CO_2 storage potential in the Western Canada Sedimentary Basin (WCSB) is on the order of hundreds of gigatonnes of CO_2. The geothermal energy potential of the WCSB in regions where the total thickness of the strata is greater than 3 km is also significant. At these depths, the fluid contained in the rock may be hot enough to economically produce power. Alberta No. 1's geothermal power project is located near Grande Prairie, Alberta (Figure 1). Geothermal power offers a number of benefits that other renewable energy sources, such as wind and solar do not offer, namely that it provides stable baseload power and may also be used as a source of heat.

However, it is financially challenging for geothermal power to compete against other renewable resources, particularly in Alberta, where it is more difficult to get a power purchase agreement owing to the decentralized nature of electricity generation.

It is imperative for geothermal developers in Alberta to find ways to improve their competitiveness. Integrating CO_2 into geothermal projects is a promising way to improve their performance and competitiveness. In this study, we conducted preliminary modeling on how CO_2 storage and geothermal energy projects may be integrated.

The results of the study, although based on conditions at the Alberta No. 1 site, will be applicable to other sites that have similar conditions, of which there are many in the WCSB and other sedimentary basins in Canada. It will also help guide future R&D into integrated CO_2 storage and geothermal projects.

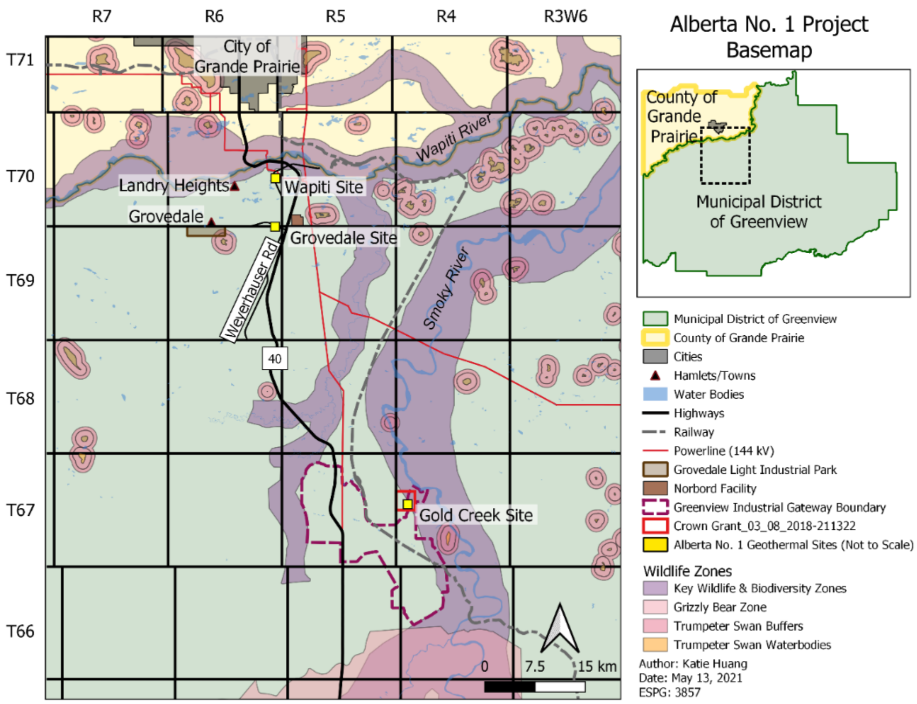

Figure 1: Alberta No. 1 project area south of the city of Grande Prairie. The project is moving forward around the Gold Creek Site, but has other options in the area.

2. Data Collection and Overview of Target Formations

Exploitation of geothermal energy, often considered a clean renewable source used for electricity generation or district heating, involves the circulation of a geothermal fluid such as water into deep (>2.5 km) hot (>250 ^{o}C) subsurface formations (Coats 1977; Brown 2000). Because most geothermal resources do not offer adequate permeability for efficient fluid circulation, some geothermal systems are engineered through hydraulic fracturing and stimulation to create permeable pathways for geothermal fluid from the injectors to the producers, referred to as the Engineered/Enhanced Geothermal Systems (EGS). Water, a common geothermal fluid, is often used to mine the heat from deep subsurface formations due to its many distinct properties, including for instance its phase behaviour and high heat capacity. Water has long been taken for granted for use in many industries, but today (relatively fresh) water is a valuable commodity in many countries and its loss in conventional EGS could have significant environmental and economic consequences (Preuss 2006). Given the high pressure, high temperature conditions in EGS reservoirs, water could act as a solvent for rock minerals with unfavourable impacts on heat extraction and fluid circulation (e.g. dissolution, precipitation, permeability reduction, Xu and Pruess 2004; Talman et al. 2020).

As an alternative to some unfavourable drawbacks for the use of water (e.g. water loss, reactive fluid/rock transport, precipitation), CO_2 has been proposed as a transmission fluid in HDR systems for reservoir creation and heat extraction (Brown 2000). With the idea of CO_2 as a geothermal working fluid, many researchers have explored the topic of mass and heat transport in CO_2-based EGS reservoirs (e.g. Brown 2000; Fouillac et al. 2004; Pruess 2006, 2008; Pruess and Azaroual, 2006; Atrens et al. 2009; Nielsen et al. 2013; Zhang et al. 2016; Sepulveda et al. 2018). Since typical EGS reservoirs operate at high temperature and high pressure conditions, CO_2 is expected to be at a supercritical state. Hau et al. (2021) emphasized the fact that such field tests should primarily show that a stable CO_2 circulation (not brine) between the injector and producer within the CO_2 plume could be achieved and maintained.

The geological and reservoir conditions of underground structures in the WCSB seem to be suitable for integrating CO_2 into geothermal projects. The research area for this project was designated by AB No. 1 and was set between R9T68 (NW corner) and R3T63 (SE corner) (Figure 2). Eighteen deep wells identified by AB No.1 were included in the first iteration of our analysis.

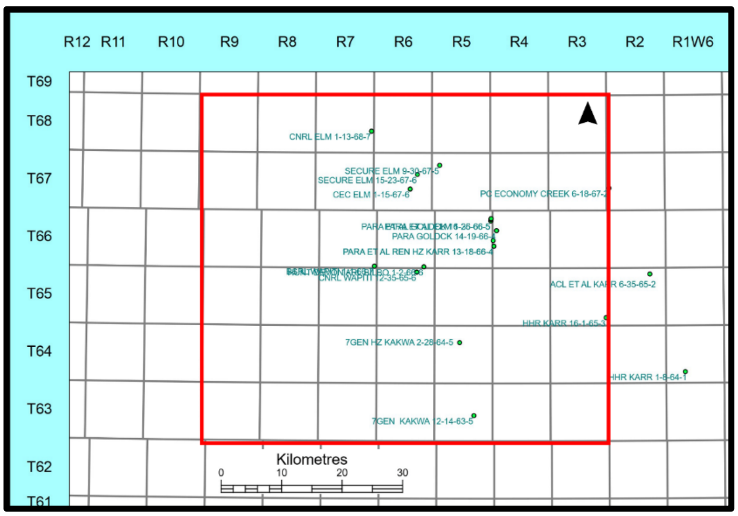

Figure 2: Research area (red frame) is between Townships 63 and 69 and Ranges 3-9 west of the 6th Meridian. Wells in this figure were the initial 18 wells identified by AB No.1.

Alberta No.1 have identified the Devonian Wabamun and Winterburn groups as potential horizons of interest. Additional formations include the Devonian Leduc Reefs and the Lower Devonian Granite Wash sandstone (Figure 3).

In order to generate a more accurate geological model of the study area, we had to supplement the wells list provided by Alberta No.1. We added 36 wells that penetrate the Watt Mountain Formation or deeper and are planning on adding several more wells to the western section to better outline the Leduc Reefs. Cross sections were built to identify Formation tops within the research area and collect relevant data for all wells, including coordinates, elevation/ KB, trajectory, LAS files, core (depth and length), and core analysis data (porosity, permeability, density).

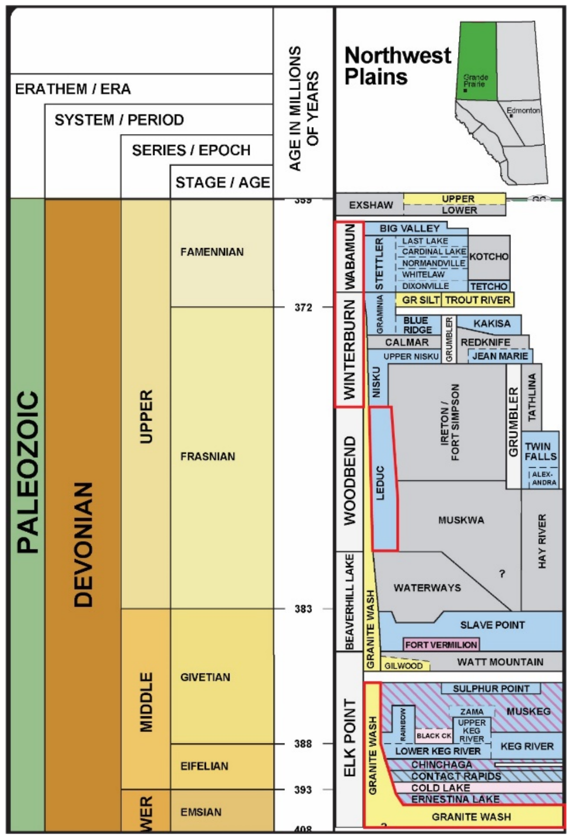

Figure 3: Stratigraphic chart of the deep section in the research area. Horizons of interest (highlighted in red) include the Wabamun and Winterburn Groups, the Leduc Reefs, and the Granite Wash sandstone. Adapted from Alberta Geological Survey (2019).

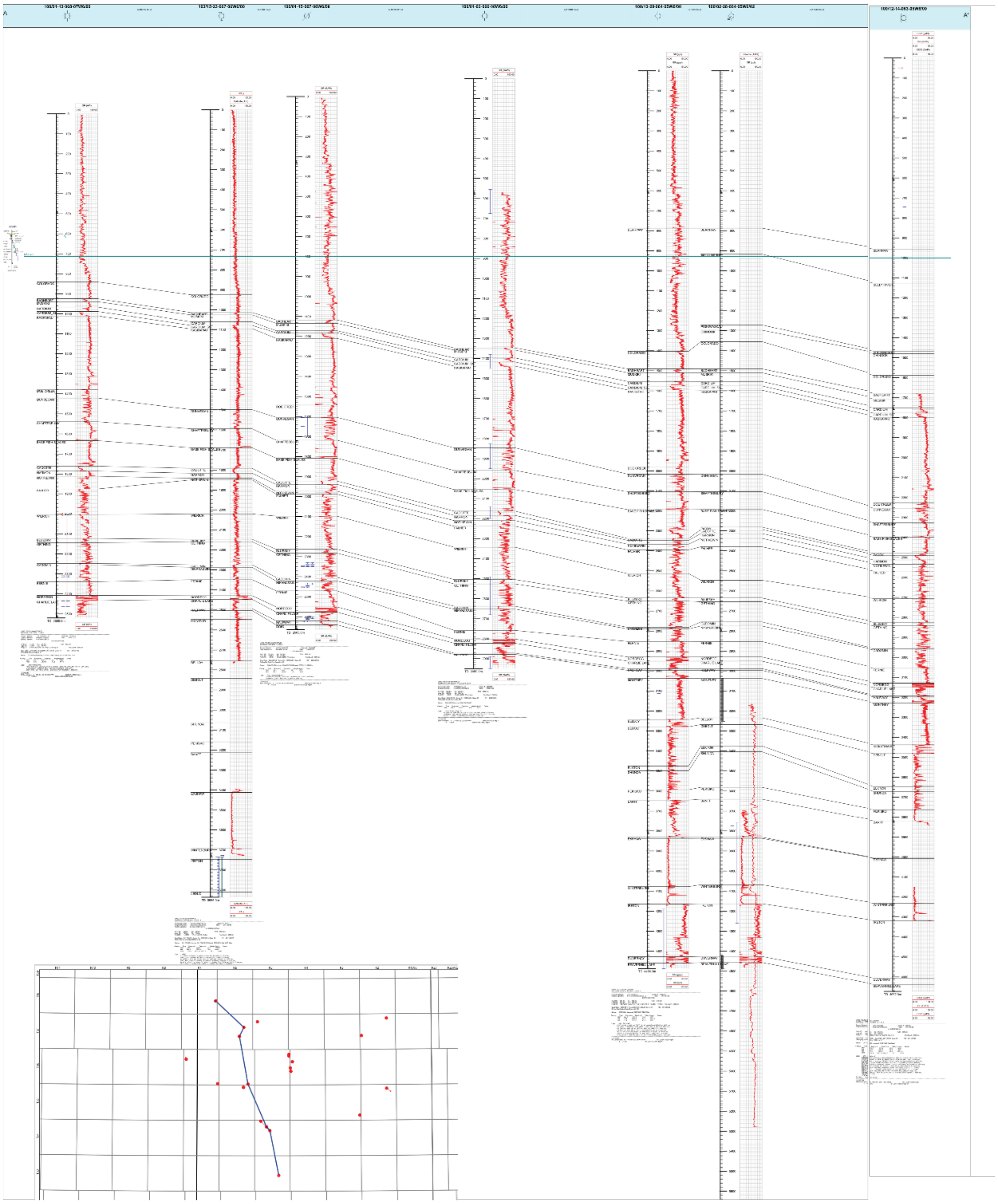

Figure 4: A cross section among some of the initial 18 wells identified by AB No.1 in the research area.

3. Geological Model and Simulated CO_2-Geothermal Scenarios

We imported relevant geological data into Petrel software package. To construct this static geological model, we also used an available regional model of Alberta (i.e. AGS-Alberta Geological Units). We extracted a sector model (90 km x 90 km) to focus on the area of interest. A tartan grid was selected with two levels of refinements in x-y directions around injection and production wells, so that 100 m x 100 m cell size in a region of 4km x 3km could be obtained for each well (Figure 5). The choice of tartan grid helps to speed up flow simulations in the areas where cold brine/CO_2 footprints would be expected.

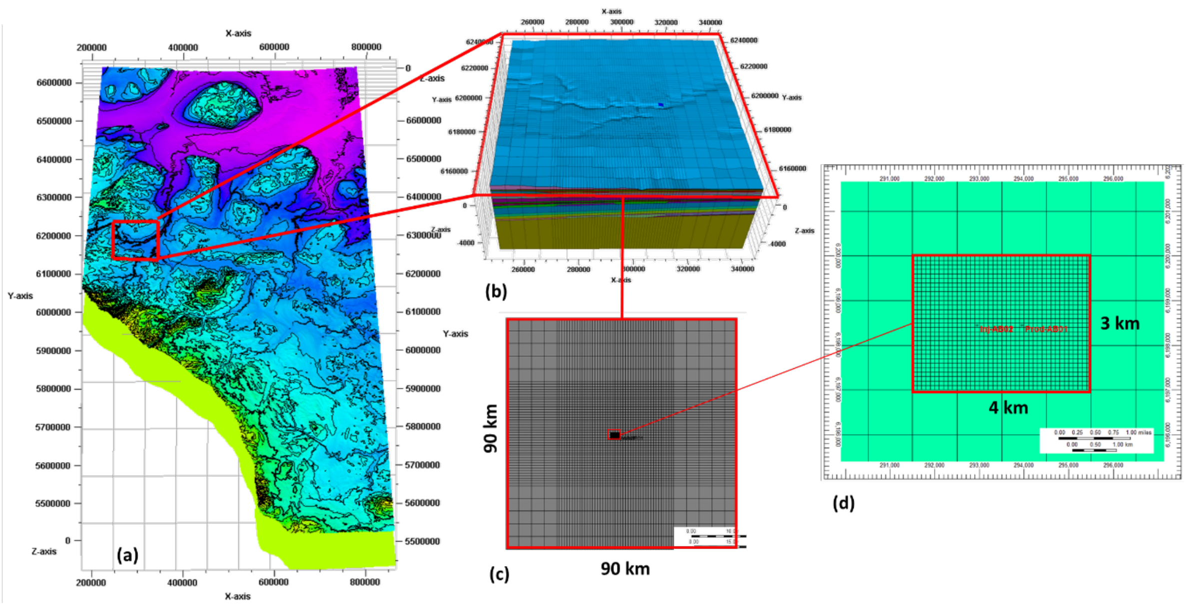

Figure 5: Model geometry for simulation studies (a) province of Alberta, (b) 90 km x 90 km sector model of area of interest (c) top view and (d) the refined zone around injection and production wells.

The petrophysical properties in the model were obtained from literature, but the input data and assumptions will be updated with new information; we assumed this early version of Petrel model is homogenous in horizontal direction so that the porosity and permeability data were distributed by direct assignment of each property throughout individual horizontal layers; vertical permeability/horizontal permeability (permeability anisotropy) was assumed 0.1. Also note that thickness of the layers could change depending on the structural information available from the parent AGS model.

The flow model was built using CMG compositional simulator (GEM). The Peng-Robinson equation of state, assuming a three-component fluid system of brine and CO_2 and trace amount of CH_4 for numerical stability was adopted. The CO_2 was allowed to dissolve in brine where solubility of CO_2 in brine was estimated by Harvey's correlation in pure water and corrected for salinity effect (Harvey, 1996). The correlations to calculate brine density (Rowe & Chou, 1970) and viscosity (Kestin, Khalifa, & Correia, 1981) were also implemented in CMG-GEM simulator. Three sets of drainage relative permeabilities for different rock types, from multiple sources including Kurz (2014), Schlumberger (2013), and Bennion and Bachu (2005), were available from previous studies. Relative permeability data from Schlumberger was sourced from unsteady-state CO_2 gas/ CO_2 equilibrium brine relative permeability tests performed on a composite core stack composed of three core plugs (Schlumberger 2013). Relative permeability, reported by Bennion and Bachu (2005), were derived from three basal Cambrian sandstone formations in the Wabamun Lake area southwest of Edmonton in Alberta. We assigned heterogeneity to relative permeabilities, distinguishing between high quality sand zones, carbonates, and poor shale sequences. No capillary pressure data were included.

4. Results and Discussions

Four different sets of simulation were conducted to investigate the various integrated CO_2-geothermal options to identify which of the following scenarios is the most feasible. Note that this is the first iteration of the model; the model needs to be calibrated with more geological and core data.

Scenario 1. CO_2 Plume Geothermal using a Well Doublet: In this scenario, CO_2 is used as the geothermal fluid between an injection well and a production well. CO_2 is injected into the formation until it creates a plume that is of sufficient size such that it can sustainably produce power for the desired lifetime of the project. Note that in this scenario, the same formation would be used to produce geothermal fluid (hot CO_2) and store CO_2 (trapped in underground formations).

Scenario 2. Conventional Brine-based Geothermal with CO_2 Storage at Adjacent Top Formations: This option assumes vertically adjacent formations are suitable for both conventional brine-based geothermal and CO_2 storage. The deeper formation, which is hotter, would be used to produce hot water for geothermal energy purposes, and the shallower formation would be used for CO_2 storage. The formations must be separated by caprocks of sufficient thickness to prevent interactions between the systems. This scenario could possess a single borehole or well doublet for injection of CO_2 and geothermal fluids.

Scenario 3. Cyclic CO_2 Geothermal Plume using a Single Well: This option is similar to the first scenario, but it relies on a single borehole to act as both the injector and the producer. Cold CO_2 will be initially injected for a long period of time to establish a CO_2 plume. Once there is a CO_2 plume of significant size, the well is shut in for a few months. The well is then allowed to produce hot CO_2 for a certain period of time, or after meeting specified rate or pressure constraints. Produced CO_2 and any additional make-up CO_2 are injected back to the underground formations and the cycles repeat.

Scenario 4. Multi-fluid Geo-Energy System: In this formulation, both CO_2 and hot water are produced to make power. The concept involves alternating between CO_2 injection and brine injection from one injector within same formation (single borehole) and produce the CO_2/brine from a production well, what we referred to as CO_2 WAG Geothermal (WAG stands for water alternating gas). The injection of CO_2 can create additional pressure that serves to reduce the amount of power required to pump hot water (Figure 6).

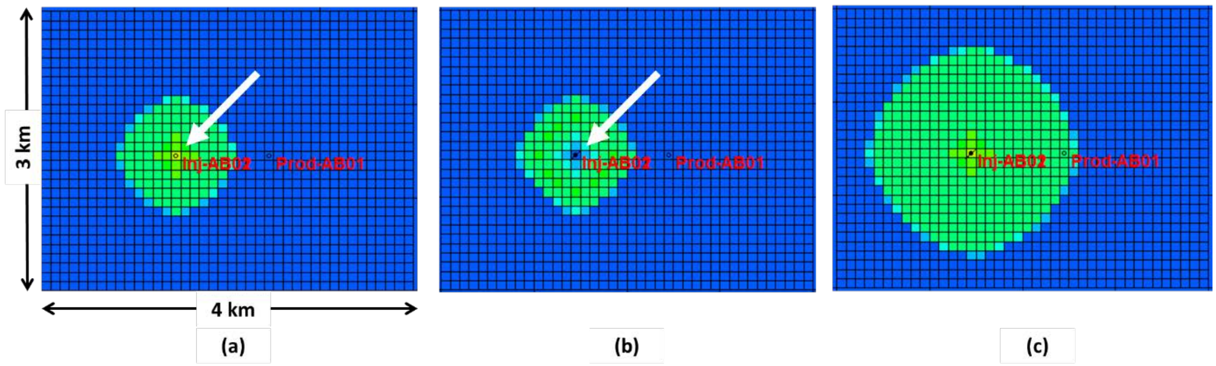

Figure 6: Top view of a target formation undergoing simulated CO_2 WAG Geothermal process using a well doublet (scenario 4). Green color represents higher CO_2 saturation and blue color represents 100% brine saturation. (a) the CO_2 plume was established. (b) note the blue shade (dominant brine saturation) around injection well and inside the CO_2 plume that shows the injector well is alternating between CO_2 and brine injection. (c) extended CO_2 plume after 25 years of WAG CO_2 Geothermal process.

Figure 7 illustrates the cumulative CO_2 mass injected during 25 years of operation in each of 4 scenarios using one injection well. The results indicate that selected formations of Wabamun and Winterburn offer huge potential for CO_2 storage. Cumulated injected CO_2 in both scenarios 1 and 2 (CO_2 Plume Geothermal and brine geothermal with CO_2 storage in adjacent tip formations) are comparable; this is because both scenarios target the same formations for CO_2 storage. In scenario 1, all produced CO_2 is assumed to recirculate back to the target formations. In scenario 2, no CO_2 is allowed to produce back to the surface. This leads to a comparable formation capacity to store CO_2 for both scenarios. Moreover, the increasing trend of cumulative injected CO_2 mass suggests that the operation can go beyond 25 years, or the injection rate and the number of injection wells can increase before meeting any storage constraints.

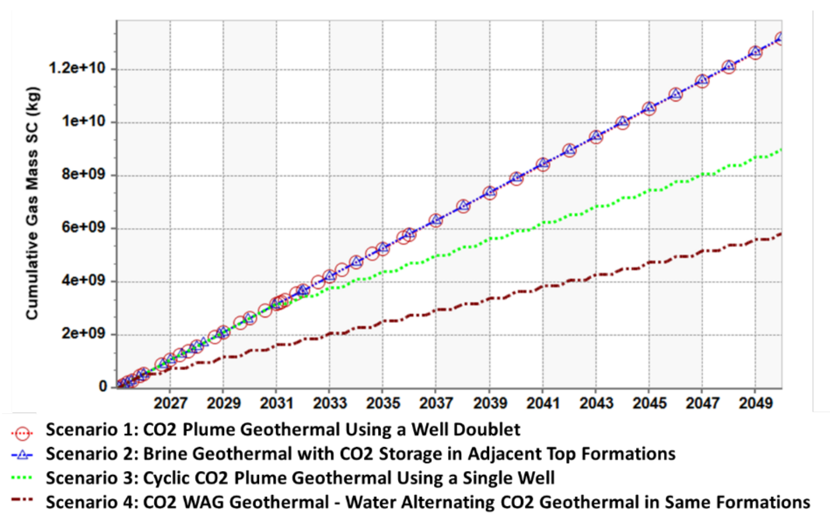

Figure 7: Cumulative CO_2 mass injected in each integrated CO_2-Geothermal scenarios.

A comparison between scenarios 1 and 3 can be made on the performance of the CO_2 geothermal process. It appears that the injectivity of CO_2 in cyclic CO_2 plume geothermal using a single borehole is less than that of CO_2 plume geothermal process with a well doublet (i.e. injector and producer at a distance). This is due to cyclic nature of CO_2 injection/production in scenario 3 where brine will be also produced along with CO_2 and it will adversely affect saturations around the injection well (e.g. lower relative permeability of CO_2).

As shown in Figure 7, CO_2 can be injected in all scenarios either at adjacent formation or same formation that is being injected with water (CO_2 WAG Geothermal). However, CO_2 WAG Geothermal process results in no to negligible CO_2 production after 25 years (Figure 8). This is interesting because it shows that CO_2 is being stored through trapping mechanisms while providing a pressure support to produce hot brine at lower pumping loads. CO_2 production in both variations of CO_2 plume geothermal process is significant. Upon heat extraction at the surface (i.e. direct heat utilization or in a CO_2 turbine/electricity generator), the idea is to recirculate the produced hot CO_2 back to the underground formations.

The difference in cumulated injected mass of CO_2 and cumulated produced mass of CO_2 will return the stored CO_2 underground during CO_2 plume geothermal process. The stored CO_2 can be used as one of key performance indicators to optimize the whole process.

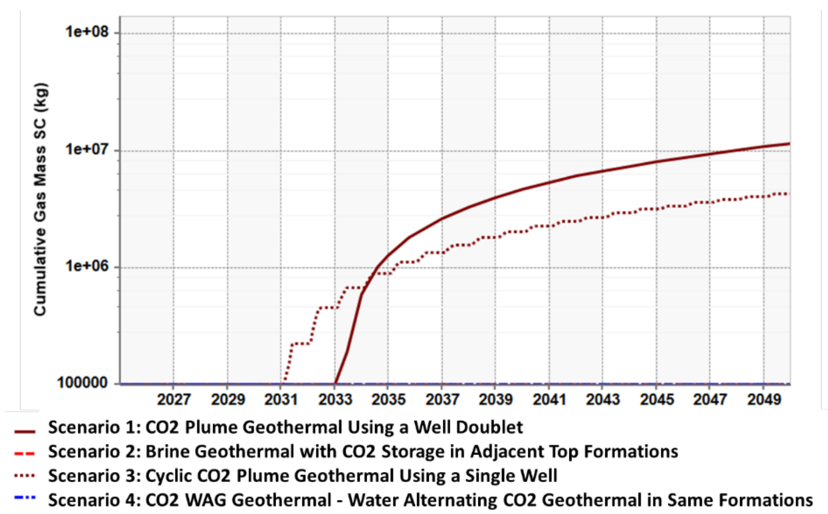

Figure 8: Cumulative CO_2 mass produced in each integrated CO_2-Geothermal scenarios.

Cumulative produced water from scenario 2 and 4 is shown in Figure 9. Alternating injection of CO_2 and brine into same formation results in less water production. The initial thought was that CO_2 could provide additional pressure support to reduce the load on pumping hot water to the surface. Figure 9 suggests that the inclusion of CO_2 can adversely affect brine production. This is probably due to the introduction of a second phase and the reduced relative permeabilities compared to the single phase brine-based conventional geothermal operation.

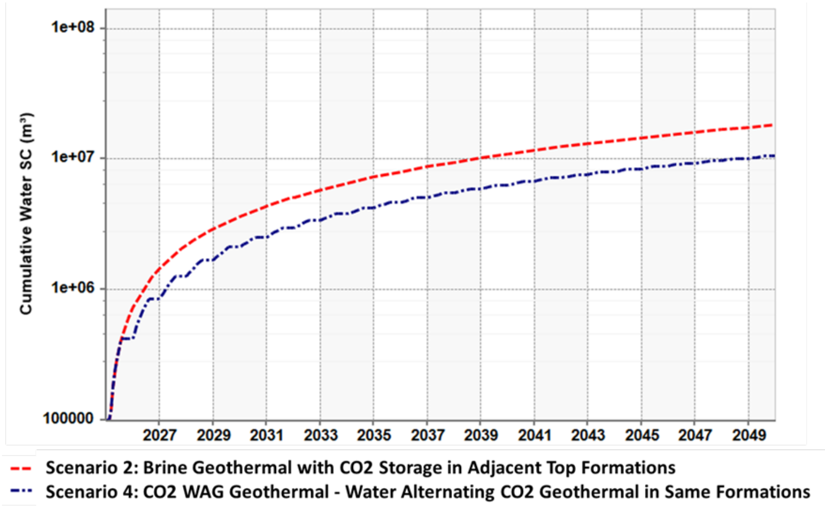

Figure 9: Cumulative produced water in each integrated CO_2-Geothermal scenarios.

As noted, one issue in employing CO_2 as a working fluid is that the process leads to the co-production of CO_2 and brine. In Figure 10, we looked at the CO_2 to water ratio in variations of CO_2 plume geothermal process. If a single bore hole is used for fluid injection and production, initially a significant amount of hot CO_2 will produce; the CO_2-to-water ratio is large. With additional cycles, the CO_2-to-water ratio decreases. This means more brine production and a decrease in flow efficiency of CO_2 plume geothermal process. Ultimately, significant brine production could kill the producer through liquid loading. On the contrary, simulations suggest that CO_2 plume geothermal using a well doublet might initially result in production of a large volume of brine at the producer; but CO_2-to-water ratio will increase during the course of operation. Proper surface facilities should be available to manage the initial brine production.

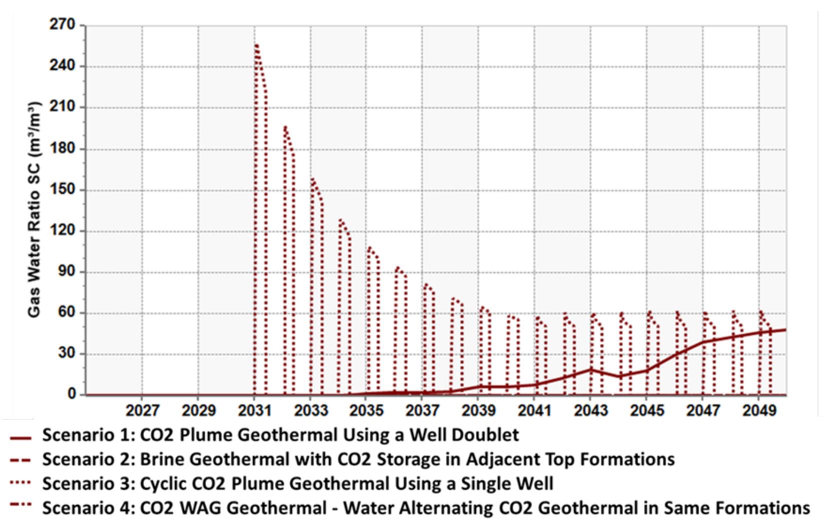

Figure 20: Produced CO_2 to brine ratio at standard condition from each integrated CO_2-Geothermal scenarios.

Figure 11 provides the top view of CO_2 mole fraction near the injection and production wells during the course of CO_2 Plume Geothermal (scenario 1). Warm color represents higher CO_2 mole fraction; cold color represents low CO_2 mole fraction; for instance, dark blue color represents no CO_2 mole fraction, i.e. presence of 100% brine. Simulation results with the base assumptions suggest the possibility of brine entering the CO_2 plume zone and into the production well from an encroaching aquifer. This highlights the significance of examining and optimization of injection/production well constraints to determine the possible existence of any working conditions for both wells (e.g. rates and pressures) to optimize brine/CO_2 production in future studies.

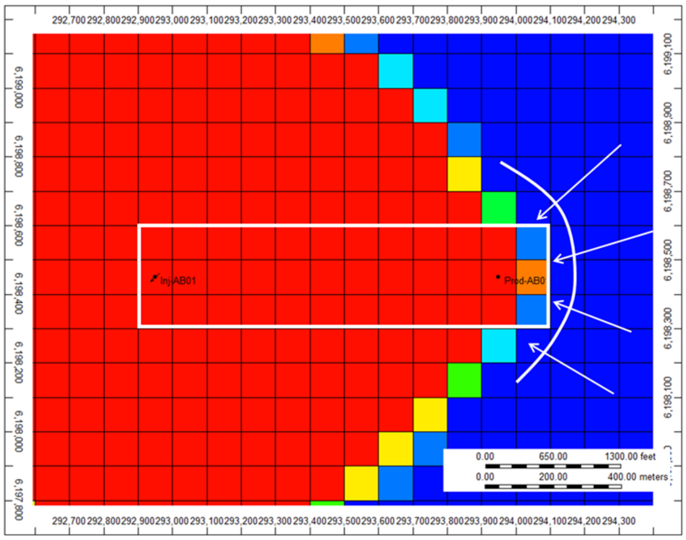

Figure 31: Top view of CO_2 mole fraction near the injection and production wells during the course of CO_2 Plume Geothermal (scenario 1). Warm color represents higher CO_2 mole fraction; cold color represents lower CO_2 mole fraction.

5. Conclusions and Remarks

This study looked into some of the possible options to integrate CO_2 storage and conventional water-based geothermal operation in order to improve their competitiveness.

Simulation results suggest that it is possible to integrate CO_2 storage and geothermal energy production. There is significant CO_2 storage capacity in the research area of WCSB. It is feasible to use a single borehole or a well doublet to inject CO_2 and brine into adjacent formations or same formations. The simulated scenarios should be used with caution as data and models are preliminary; this feasibility study will be updated with additional geological and production data.

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