Geothermal Energy and Carbon Dioxide Sequestration

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Geothermal Energy and Carbon Dioxide Sequestration

by

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A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
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Under the climate change crisis evolving from excessive greenhouse gas emissions, society is seeking ways to answer the call to produce clean energy. Carbon capture, utilization, and storage (CCUS) and geothermal energy are two major options to reach carbon neutrality. The research documented here examined four ways to lower emissions. In the first study, an enhanced geothermal system (EGS) in the Basal Cambrian Sandstone Unit in Alberta, Canada is explored. The second study examines the potential to combine underground CO₂ sequestration and geothermal energy harvesting. The third study explores CO₂-Enhanced Gas Recovery (CO₂-EGR) in an offshore natural gas field located in the South China Sea. In the last study, the first China offshore CO₂ sequestration operation in a shallow subsea feldspar-quartz sandstone formation is examined. The results demonstrate that open-loop EGS realizes an energy produced to energy invested ratio from 4 to 9 depending on operating rate and suggest that hydraulic fracturing accelerates energy harvesting and energy efficiency over the early process stages but the greater the injection rate, the smaller is the benefit of hydraulic fracturing. Second, combining both CO₂ sequestration and geothermal operations is possible with commercial value and environmental benefits. Third, CO₂-EGR demonstrates greater natural gas production together with CO₂ sequestration and that there is potential that the process could be carbon neutral or negative. Fourth, offshore CO₂ sequestration in a feldspar-quartz sandstone formation is possible and showcases that a dynamic behaviour occurs at the CO₂ plume front where a relatively small amount of carbonate mineral precipitates which is subsequently dissolved when the acidified water in the plume passes the prior front location. The results showcase contributions for both CCUS and geothermal energy towards carbon emissions reduction.
Preface

The research work compiled in this Ph.D. thesis was carried out to develop carbon capture, utilization, and storage (CCUS) and geothermal energy recovery. As part of the research, the author (student) collected, prepared and processed the geology data, designed the simulation model to analyze the data, analyzed the results, and drafted this thesis. Dr. Ian Gates provided funding to support the research, oversight on the research, intermediate and final editing of the manuscripts arising from the research, and final editing of the thesis. Dr. Jacky Wang provided guidance and support on the simulation modelling. Original publications from the research documented including in this thesis is list below:

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Dr. Ian Donald Gates has been an ideal teacher, mentor, and supervisor, without whom the concept of using geothermal and CCUS to approach carbon neutral would not have been raised in my mind. I would like to sincerely acknowledge his valuable guidance, relentless support, discerning thoughts and loads of inspiration that led me forward to delve deeper into the issue.

I sincerely express my gratitude to Dr. Jacky Wang, my co-author with his invaluable help on model building. His suggestions and valuable ideas always help me come out of dilemmas.

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I also thank CNOOC China limited, Shenzhen Branch; CNOOC China Limited, Hainan Branch and CNOOC Research Institute Limited for providing geological data, wellbore locations, and production gas rates, pressure, and composition, and other information for CO₂ injection for the target formation for Chapter 5 and 6. Due to confidentiality, well and geological formation names are not disclosed.

Many thanks to my parents, the research group members and my friends who spared their times for moral support during my study.
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<td>CCS</td>
<td>Carbon Capture and Sequestration</td>
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<td>CCUS</td>
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<td>Hot Dry Rock</td>
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CHAPTER 1: INTRODUCTION

1.1. Background

The increasing emissions greenhouse gases (GHGs) has become a focal point for national strategies aimed at lowering GHG emissions as well as finding options for the carbon dioxide utilization, conversion, and sequestration (Lackner, 2003; Ma et al., 2009; Alper and Orhan, 2017). In 2022, global fossil-fuel based GHG emissions reached ~36.6 GtCO$_2$/yr, which was 1% higher than that emitted in 2021 (Friedlingstein et al., 2022). For Canada, the total GHG emissions in 2020 were equal to ~672 MtCO$_2$e which was an 8.9% decrease from 2019 (Government of Canada, 2022). In 2015, the province of Alberta, hosting the world’s third largest oil proven reserves and Canada’s largest fossil fuel producer, produced ~256.4 MtCO$_2$e from upstream and downstream activities in the natural gas, light and heavy crude oil, oil sands, and oil refining and upgrading operations (Canada Energy Regulator, 2022). Given these large emissions, there is significant motivation to accelerate the deployment of carbon dioxide conversion, decarbonization technologies, emissions reduction approaches, and carbon capture and sequestration (CCS).

The impacts of rising GHG concentration in the atmosphere is resulting in climate change which, for example, has manifested itself in the form of unusual temperature fluctuations (cold and hot), deglaciation, elevated temperature leading to forest fires, warming coastal waters leading to harm to coral reefs on the environmental side (Muhlfeld et al., 2020; Paoli et al., 2010). Beyond air pollution, rising sea level, and damage to biodiverse environments, these impacts present
themselves as serious human health issues such as respiratory disease and lung malfunction (Lim et al., 2012).

As a result of climate change, there have been several global initiatives with the goal of reducing GHG emissions. For example, the Paris Agreement (2015) was signed by 195 countries. Canada, as one of the signatories, has committed to reduce GHG emissions by 30% below 2005 levels by 2030 and achieve a net-zero emissions by 2050. According to a Government of Canada 2021 report, Canada is attempting to accelerate actions in their climate plan to ensure Canada can exceed their 2030 emissions reduction goals.

Regulations and policies in many nations are motivating and accelerating carbon dioxide reduction, conversion, and sequestration technology (Jiang et al., 2020; Chen et al., 2022). Carbon taxes and credits are concepts that many nations have adopted to quantify the amount of carbon dioxide generated versus the amount eliminated and is agnostic to any activity that generates carbon dioxide emissions (Gupta, 2011). Research shows that there are typically three ways to earn carbon credits: 1. convert carbon dioxide into other products, 2. conduct carbon sequestration, i.e., CCS/CCUS, and 3. reduce fossil fuel energy use by using renewable or nuclear energy. The Canadian government has a regulated carbon dioxide price that will rise from $50 to $170 per tonne from 2022 to 2030 (Government of Canada, 2021).
1.2. Renewable Energy

Renewable energy consists of solar/photovoltaic, wind, geothermal, solar thermal, tidal and ocean thermal energy generation (Ericson et al., 2019; Choi et al., 2017; Saadawi et al., 2019; VK et al., 2019). Since renewable energy is emerging into maturity, its prohibitively expensive cost in the past has fallen to an acceptable range where it is becoming cost competitive with fossil fuel options (Ericson et al., 2019). Recent research shows that renewable energy can even be used in oil and gas recovery operations. In particular, geothermal and solar thermal may have potential for use in thermal EOR recover such as SAGD, hot water flooding, steam flooding, and in-situ combustion (Saadawi et al., 2019); solar/photovoltaic, wind, tidal and ocean thermal has the potential to provide power which can easily be applied on any primary, secondary, and tertiary recovery (Ericson et al. 2019). However, this will only deal with the upstream side of the petroleum sector which is a relatively minor in terms of its life cycle emissions – the majority, of order of 80% of emissions arises from the end-use of oil and gas (Schipper et al., 1997; Herzog, 2009).

1.3. Geothermal Energy

Geothermal energy is one form of renewable energy that is harvested by heat transfer from underground hot rock and heat carrier medium which is brought to the surface for use of that heat (Tester et al., 2006). Usually, the geothermal source temperature for electricity production require 150°C or higher. However, by using binary plant, this requirement can reduce to around 95°C (Dincer and Ezzat, 2018; EIA, 2022). There are more than 30 countries that have operating geothermal energy plants as illustrated in Figure 1.1 (THINKGEOENERGY, 2023). Geothermal
energy is not only applied for electricity production: geothermal resources with temperatures between 150 and 90°C can be used for district heating. Also, geothermal resources with temperatures between 90 and 30°C can also be used for household heating, food processing, greenhouse heating, and aquaculture (Dincer and Ezzat, 2018). On March 23, 2023, Alberta has the first Canada geothermal power project co-produced with natural gas by FutEra Power in Swan Hills.

Figure 1.1: Distribution of large-commercial scale geothermal energy plants (THINKGEOENERGY, 2023).
1.4. Development of CCS/CCUS for Reduction of GHG

Carbon Capture and Storage (CCS) is a broad emission reduction concept for removal of carbon dioxide from the atmosphere or from industrial processes where it is sequestered in underground pore space (Budinis et al., 2018). The origin of this concept was first proposed by Marchetti (1977). CCS is seen as a major component of decarbonizing industrial operations, for example, the Pathways Alliance announced by major oil sands companies for lowering carbon dioxide emissions from their operations (Pathways Alliance, 2022). Commercial-scale CCS process can be divided into four steps: 1. CO₂ capture, 2. CO₂ transport, 3. CO₂ storage (Bui et al., 2018). As yet, there are few long-term large-scale CCS operations where a complete techno-economic analysis (TEA) has been conducted for its evaluation (Jiang et al., 2017). TEA of large-scale CCS to date suffer from uncertainties (Van et al., 2020, Rubin et al., 2012). Bui et al. (2018) examined commercial-scale status of CCS development with TRL Rank 1 to 9 (1 as concept and 9 as commercial). From their outcomes, Bui et al. ranked proof-of-concept to commercial carbon dioxide capture technologies and operations. For example, chemical absorption is a mature technology, but integrated gasification combined cycle (IGCC) with CCS has yet to mature. They found that carbon dioxide transport modes are well established and relatively mature and that storage is relatively mature for CO₂-enhanced oil recovery (EOR) but ocean and mineral storage are still emerging with many uncertainties. They also described that carbon dioxide utilization processes in the food and beverage and chemical production industries are relatively mature.
On carbon dioxide capture, CCS can be implemented on any industrial systems that emit carbon dioxide but the key issue is on its purification, for example, from flue gas. For example, SaskPower’s Boundary Dam in Estevan, Saskatchewan, Canada is the world’s first large-scale coal-fired power station equipped with CCS operating since 2014. It has captured 1 Mtpa of carbon dioxide (Canada Energy Regulator 2016). Some of the captured carbon dioxide has been transported to the Weyburn oil field for a CO2-EOR project whereas the rest is being sequestered 3.4 km underground at the Aquistore geological storage site (Rostron et al., 2014).

On utilization, carbon dioxide injection for oil and gas enhanced recovery does have the benefit that some fraction of the injected carbon dioxide is stored within the reservoir (Ampomah et al., 2017; Li et al., 2019). CO2-EOR has been widely accepted as an effective technique to increase oil recovery. The first large-scale CCS operation for CO2-EOR project was operated in Sharon Ridge oil field at Texas, United States in 1972 (Liu et al., 2018). Gozalpourt et al. conducted field research and found out most of CO2-EOR projects has a CO2 utilization efficiency of 6,000 to 8,000 Mscf/bbl (167- 227 sm³/bbl) helping reservoirs gain over 8% greater recovery factor from the field (about one tonne of carbon dioxide injected realizes 2.5 to 3.3 bbl of oil) with ~60% of the injected carbon dioxide being sequestrated in the reservoir.

In shale gas reservoirs, methane is trapped within natural fractures and intergranular porosity or sorbed onto or dissolved into organic matter like kerogen and bitumen (Iddphonce et al., 2020; Eliebid et al., 2017; Curtis, 2002). Carbon dioxide enabled shale gas recovery is a dynamic displacement process between CO2 and CH4 caused by pressure gradient and competitive adsorption (Huo et al., 2017, Mohagheghian et al., 2019). This technology has the potential to
offer a closed cycle of CO₂ utilization: the carbon generated from methane combustion is stored within the reservoir from which the methane was obtained (Klewiah et al., 2020).

CCUS is a strategy that couples both CCU and CCS together during the upstream operation (Schrag, 2007). Bachu (2016) claimed that although not all oil reservoirs are suitable for carbon dioxide injection for EOR or EGR, but Alberta, Canada, where nearly 12,000 oil reservoirs are not yet under tertiary recovery and could potentially be used for CO₂-EOR or EGR. Bachu (2016) also pointed out that in Alberta there are 38 large carbon dioxide sources (majority power generation and oil sands production) with cumulative emissions about 106 Mt/year with 29 oil fields in a radius of 300 km. By using CCUS technology and pipeline infrastructure, an 80% of potential incremental on oil recovery can be expected. However, it remains unclear as to the net amount of carbon dioxide that would be fixed in the reservoir in these operations.

On storage, carbon dioxide sequestration refers to permanent fixation of the gas in underground pore spaces where its mobility is limited and it does not have any secondary uses (Benson and Cole, 2008). Carbon dioxide fixation in underground systems occurs through structural, residual, solubility, and mineral trapping (Benson and Cole, 2008; Gislason et al., 2014). Structural trapping refers to the trapping of carbon dioxide gas or supercritical fluid in a structural trap, e.g., an anticline with a low permeability caprock. One key desired feature of a caprock is that the gas capillary entry pressure is greater than the buoyancy or hydrodynamic forces so that the carbon dioxide does not penetrate the caprock. Residual trapping refers to the case where carbon dioxide gas or supercritical fluid is rendered immobile by capillary pressure in fine pores. Solubility trapping is the case where the carbon dioxide is dissolved in the formation water. After
dissolution, the density of the water is slightly higher than the original water which leads to buoyancy-driven convection cells in the aquifer. Mineral trapping is the case where the carbon dioxide dissolves in the water and the acidified water reacts with minerals in the reservoir rock leading to mineral dissolution or precipitation. If precipitated, mineral trapping can permanently fix the carbon dioxide in the form of a mineral within the aquifer. However, it has been shown that natural mineralization needs thousands of years to occur over meaningful volumes. Therefore, one option for speeding up mineralization is by dissolving the carbon dioxide in water on surface and then injected it into the formation (Gislason et al., 2014; Kelemen et al., 2020). By injecting water with dissolved carbon dioxide water into the target formation, the stringent low permeability requirements for the no cap rock can be relaxed since there is no gas phase within the aquifer, solubility trapping occurs immediately, and mineral trapping will occur much faster. Unfortunately, this method requires substantial water to dissolve the carbon dioxide, only about 5% of injected mass being carbon dioxide (Gislason et al., 2014). However, this might not be such an issue for offshore sequestration where seawater can be used – seawater has slightly less carbon dioxide solubility than that of freshwater at the same pressure and temperature (Snæbjörnsdóttir et al., 2020). For the real field case, even though offshore storage still in the early stage, Equinor successfully conducted the Sleipner CCS project as the world’s first offshore CCS operation in the North Sea near Norway in 1996 (Ma et al., 2022).

1.4. Research Question

The review of the literature is summarized in Chapter 2. The introduction above, as well as the literature review, reveal that there are still questions for carbon dioxide sequestration and
combinations with geothermal energy production. The research documented in this thesis reports on geothermal energy production, carbon dioxide sequestration with geothermal energy production, and two studies on carbon dioxide sequestration in offshore operations. The research questions that are examined are as follows.

1. The Basal Cambrian Sandstone Unit (BCSU) is the sequestration target for the Shell Quest carbon dioxide sequestration operation in Alberta, Canada. It is a warm formation, having temperature of about 100°C. This aquifer was studied for its capacity for geothermal energy production following the research conducted by Chong et al. (2021, 2022). Here, an enhanced geothermal system (EGS) is considered: what is the performance if hydraulic-fracturing EGS is applied on the BCSU?

2. Given that it is used as a carbon sequestration site, one option that has not been studied for the BCSU is a combined sequestration and geothermal energy production operation. Here, an examination of a combined sequestration-geothermal energy production process is examined: what is the performance of sequestration combined with geothermal energy harvesting where the process is restricted to produce no carbon dioxide from the BCSU? Will this combination system show more value than just a pure geothermal harvesting system?

3. A large multinational petroleum company is producing natural gas from an offshore reservoir. Here, the potential for carbon dioxide sequestration with enhanced gas recovery is explored. Specifically, how does the natural gas reservoir respond to carbon dioxide injection? What is the carbon dioxide storage capacity and efficiency in the reservoir?
4. Many nations are examining options for sequestration and to lower risk, subsea offshore carbon dioxide sequestration options are being considered. Here, an offshore aquifer target in the South China Sea is explored for carbon dioxide structural, residual, solubility, and mineral trapping based on a prospective target for a large petroleum company. The questions that are examined include what is the structural, residual, solubility trapping of the system, what is the extent of mineralization, and what is the time scale for mineralization?

1.5. Organization of Thesis

The research contained in this thesis is structured in seven chapters as follows. Chapter 2 provides a detailed literature review of geothermal, geothermal with sequestration, sequestration in offshore aquifers, and enhanced gas recovery. Chapter 3 consider applying a hydraulic-fracturing EGS on Basal Cambrian Sandstone Unit (BCSU) to study the possibility for BCSU on conducting a geothermal harvesting activity. Chapter 4, the research discuss a combination system of CCUS plus CO₂-EGS perform on Basal Cambrian Sandstone Unit (BCSU). This reveals besides a pure geothermal plant, what possibility can be implemented on this reservoir to make it more valuable. In Chapter 5 examines the performance on CCUS aiding an end stage offshore natural gas recovery. This research will study the potential for this reservoir conducting a CO₂ sequestration activity and how much improved on enhancing the natural gas recovery. Chapter 6, the research analysis the performance of structural, residual, solubility, mineral trapping when CO₂ injecting into an offshore feldspar-quartz sandstone formation. This research also intent to show whether wellbore will block under corresponding condition and what mineral
is the majority precipitated. Finally, Chapter 7 gives the major conclusion and recommendations for the research present in this thesis.
CHAPTER 2: Literature Review

2.1. Introduction

Every individual, event, organization, service, place, or product activity will generate greenhouse gas (GHG) emissions, a concept named carbon footprint has been proposed over decades for measure the total amount of GHG emissions from those action (Wiedmann and Minx, 2008). It also expresses as carbon dioxide equivalent (CO$_2$e). For example, Figure 2.1 shows potential carbon dioxide generation sources within the oil and gas industry including upstream production, downstream refining and processing, transportation, and end product customer consumption. GHG emissions are generated from all upstream and downstream supply chain processes, and when the fuel is actually consumed. All industries have similar GHG emission sources along their internal and external supply chains.

![Figure 2.1: GHG emission sources for the oil and gas industry.](image)

GHG emission modelling is complex with many input parameters all exhibiting degrees of uncertainty. As an example, Umeozor et al. (2018) model for unconventional tight rock is described below. This model describes a method for calculating the total potential emissions data
coming from preproduction upstream unconventional tight rock processes (including drilling, fracking and flowback) expressed as a sum of potential direct methane releases that be captured, flared or vented and energy consumption emissions:

$$Q_{\text{CO2eq}} = \text{direct releases + energy consumption}$$

$$= (\text{mud gas + flowback gas}) + (\text{drilling + mud flow + hydraulic fracturing}) \quad (2.1.1)$$

Mud gas $$Q_{\text{CO2e,m}} = \sum_a GW P_a \xi_a \rho V_m$$

with

$$V_m = \frac{\pi r_b^2 L_{pz} \theta (1 - s_l)}{4 B_g} = \frac{\pi r_b^2 L_{pz} \theta [1 - \left(\frac{\text{wor}+1}{\text{gor+wor}+1}\right)]}{4 B_g} \quad (2.1.3)$$

where $$\rho$$ is the gas density, $$r_b$$ is the radius of the wellbore, $$L_{pz}$$ is the well length within the pay zone, $$\theta$$ is the reservoir porosity, $$s_l$$ is the liquid saturation, $$B_g$$ is the gas formation volume factor, $$\xi_a$$ is the composition of the GHG component $$a$$ in the gas (Umeozor et al., 2018). The range of CO2 global warming potentials, GWP, is 1 for carbon dioxide and 28−36 for methane (United States Environmental Protection Agency, 2020). Flowback emissions are:

$$Q_{\text{CO2e,fb}} = q_{g,\text{peak}} [ (\lambda - 2) + (\lambda + 2)e^{-\lambda} ] \quad (2.1.4)$$

where $$q_{g,\text{peak}}$$ is the peak gas production rate from the well and $$\lambda$$ is a parameter related to the flowback duration and peak gas value (between 0 and 1) for characterizing the shape of the
flowback profile and calibrated \( \lambda \) value for general shale basins study is 0.75 (range from 0.6 to 1) (Umeozor et al., 2018). Drilling emissions are:

\[
Q_{\text{CO2e,d}} = X_{\text{CO2}} \frac{E_d}{\eta_d \eta_{pm}} \tag{2.1.5}
\]

with \( E_d = \sum_j \sum_i (\beta w \Delta l \varphi)_{i,j} (\cos \alpha_{i,j} + \mu \sin \alpha_{i,j}) \)

\[+ \sum_k \sum_i (\beta w \Delta l \varphi)_{i,k} \left( \frac{\sin \alpha_{i,k} - \sin \alpha_{i,k-1}}{\alpha_{i,k} - \alpha_{i,k-1}} \right) + \mu_{i,k} \frac{\cos \alpha_{i,k} - \cos \alpha_{i,k-1}}{\alpha_{i,k} - \alpha_{i,k-1}} \]  \tag{2.1.6}

where \( X \) is the length of wellbore drilled, \( E_d \) is drilling energy use, \( \eta_d \) is the drilling motor efficiency, \( \eta_{pm} \) is the prime-mover efficiency, \( \beta \) is buoyancy factor, \( w \) is unit weight of drill string, \( \Delta l \) is length of each section of drill string (including drill bit), \( r \) is radius of tool joint, and \( \varphi \) is the total angular displacement of section \( i \) of the drill string through the \( j/k \) segment of the wellbore (Umeozor et al., 2018). The mud flow emissions are:

\[
\text{Mud flow use } Q_{\text{CO2e,m}} = X_{\text{CO2}} \frac{E_m}{\eta_p \eta_{pm}} = X_{\text{CO2}} \frac{\sum_j \sum_i \Delta P_{ij} \rho_{ij} \Delta t_{ij}}{\eta_p \eta_{pm}} \tag{2.1.7}
\]

where \( E_m \) is mud circulation energy use, \( \Delta P \) is the pressure differential of the pump with frictional and dynamic losses, \( \eta_p \) is the pump efficiency, \( \eta_{pm} \) is the prime-mover efficiency and \( i \) and \( j \) are indexes for the drill string and wellbore segments sections (Umeozor et al., 2018). The emissions from hydraulic fracturing are:
\[ Q_{\text{CO2.h}} = X_{\text{CO2}} \frac{E_h}{\eta_p\eta_{pm}} = X_{\text{CO2}} \frac{E_{\text{frac}} + E_{\text{fric}}}{\eta_p\eta_{pm}} = X_{\text{CO2}} \frac{\frac{aC}{n+1} (t-t_i)^{n+1} q P_{\text{ref}} (t-t_i) + \sum q_j \Delta P_j \Delta t_j}{\eta_p\eta_{pm}} \]

where \( E_{\text{fric}} \) is the frictional losses, \( q \) is the volumetric injection rate, \( P_{\text{ref}} \) is the reference pressure which equal to hydrostatic pressure due to the fluid column in the wellbore and \( j \) is each fracturing stage along the horizontal section (Umeozor et al., 2018). From Umeozor’s analysis, it was shown that flowback was a significant contributor with CO\(_2\)e emissions at ~4810 Mg CO\(_2\)e per well, in the pre-production part of the natural gas supply chain. Their results showed that well dimensions, e.g., lateral casing design also influences pre-production energy requirements. This can be understood by comparing the energy needed to pump mud through a 5” lateral casing compared to that through a 6” or 7” lateral casing. In total, there are over 30 parameters in the model each with their uncertainty. This model demonstrates that GHG emission modelling is complex and uncertain.

In another example, Burnham et al. (2012) examined GHG emissions in the shale gas upstream and downstream. Flaring and venting from well equipment occurs at a mean value of 0.469 gCO\(_2\)/MJ and shale gas venting from processing occurs at 0.832 g CO\(_2\)/MJ. Jiang et al. (2011) estimated a total of 5500 tCO\(_2\)e is emitted during preproduction per well which equivalent to 1.8 gCO\(_2\)e/MJ of natural gas produced over the lifetime of the wall for Marcellus shale gas upstream GHG emissions. The results show that the completion stage is the largest GHG emission contributor. Venkatesh et al. (2011) estimated the mean life cycle GHG emissions to be 66g CO\(_2\)e/MJ and ~25% of life cycle emissions is from natural gas production, processing, and transport.
Yeh et al. (2010) compared the GHG emissions from land use aspect between California and Alberta conventional oil production. They showed that California conventional oil emitted less than 0.4 gCO$_2$e/MJ whereas Alberta conventional oil emitted 0.1–3.4 gCO$_2$e/MJ. Yeh et al. (2017) also recorded the GHG emission from primary exploration wells to the refinery entrance gate for California oil production is around 15 gCO$_2$e/MJ while the US average is about 6-8 gCO$_2$e/MJ (includes conventional and unconventional crude oil production). According to the Government of Canada (2022), there is a total of 25 Mt CO$_2$e emitted during conventional oil production in 2020 from Canada (17 from conventional light oil production and 6.5 from conventional heavy oil production).

Yeh et al. (2010) also compared the GHG emissions from land use aspect between California in-situ oil sands production and Alberta surface mining oil sand production. They found that California in-situ oil sands emitted less than 0.4 gCO$_2$e/MJ but Alberta surface mining oil sand is about 0.8 to 10.2 gCO$_2$e/MJ. Yeh et al. (2017) also recorded the GHG emission from primary exploration wells to the refinery entrance gate for Canadian in-situ oil sands about 15 to 30 gCO$_2$e/MJ and mining oil sands around 12 to 25 gCO$_2$e/MJ. According to the Government of Canada (2022), 81 Mt CO$_2$e is emitted from oil sand production during 2020 in Canada.

What is clear from this analysis is that fossil fuel production, transport, storage, and end-use all produce emissions. Given motivation to lower GHG emissions, one option would be to reduce global reliance on fossil fuels. Another would be to eliminate the GHG emissions resulting from the fossil fuel supply chain and its end use. The research in this thesis focuses on the latter.
2.2. Combined GHG Sequestration with Harvesting of Geothermal Energy

Geothermal energy resources are classified as drillable assets with thermal energy contained in the rock with/without fluids where viable and useful amounts of heat can be recovered to surface (Tester et al., 2006). Traditional geothermal energy harvesting typically consists of pumping cold fluid into the geothermal reservoir and producing heated fluid to the surface (Wang et al., 2018). In most cases, the fluid is water – produced water is injected into the formation. In some studies, carbon dioxide has been examined as the working fluid. Geothermal heat harvesting is very sensitive to energy losses in the production well, the flow rate of the work fluid, and the nature of the geothermal reservoir with respect to its flow conductivity (permeability, fractures), fluid volume (pore space, porosity), and supply of heat from layers under the geothermal target (Wang et al., 2018). Rahmanifard et al.’s (2019) research showed that geothermal energy in Alberta not only lowers GHG emissions but also creates economic benefits with respect to gross domestic product (GDP) and jobs.

A high-grade geothermal resource should have several advantages such as high average thermal gradients, high permeability and porosity, sufficient fluids in place, and adequate fluid recharge (Tester et al., 2006). Temperature gradient is key parameter when determining the potential for heat delivery from a geothermal energy reserve. However, not all high temperature geothermal reservoirs are good harvesting candidates. For example, a geothermal reservoir which has high temperature but low permeability and porosity may present challenges for heat extraction to the surface (Kelkar et al., 2016; Wang et al., 2018). It is rare to find geothermal reservoirs that match all high-grade conditions (Häring et al., 2008). This is a reason for enhanced geothermal systems
(EGS) where the reservoir has to be altered to make it more suitable for heat harvesting (Häring et al., 2008). Examples are hydraulic fracturing-EGS and CO₂-EGS.

There are two general approaches for geothermal heat extraction: closed-loop and open-loop systems. In a closed-loop system, there is no interaction of the working fluid with the geothermal reservoir rock or fluids contained in the rock (Self et al., 2013; Blázquez et al., 2017). The working fluid remains within a pipe and circulates within the pipe through the geothermal target reservoir. Heat is provided to the working fluid by conduction through the pipe wall. Closed-loop systems are the method of choice for small residential units (Self et al., 2013). In most cases, the working fluid is water with an antifreeze chemical, but recently carbon dioxide has also been considered as a heat carrier option since supercritical carbon dioxide (SCCO₂), at same pressure drop and geothermal reservoir temperature, has approximately 3.7 times larger mass flow rate (due to its lower viscosity) and 50% greater thermal extraction rate (due to the increased flow rate) (Casasso and Sethi, 2014; Sun et al., 2018; Pruess, 2006). Closed-loop methods have the advantage that they can be placed into geothermal targets with no or very low permeability (Van et al., 2020). However, closed-loop systems suffer from limited heat exchange area (the outer pipe wall) which limits the amount of extracted heat from the geothermal reservoir (Sanner et al., 2001).

In an open-loop system, the working fluid is injected into and flows through the geothermal reservoir rock which is then produced from the reservoir to surface using a production well (Sanner et al., 2001; Self et al., 2013). In this case, at the onset of the operation, the injected fluid pressurizes the fluid hosted in the reservoir which then is forced into the production well. At
some point, the working fluid breaks through to the production well and is then produced to the surface. In this process, the working fluid, as it flows through the geothermal reservoir, accumulates heat from the rock along the path toward the production well and finally back to surface (Di et al., 2022). The working fluid can be re-cycled on surface and re-injected into the geothermal reservoir (Russo and Civita, 2009). One key advantage of open-loop systems is that the heat transfer area is large and is controlled by the rock specific surface area and the spacing between the injection and production wells. In some cases, the injection and production wells are far from each other and the ability to re-cycle the working fluid is difficult. In many open-loop approaches, water (or the produced brine) is the working fluid. In other approaches, carbon dioxide is being explored as a working fluid. In carbon dioxide systems, if a part of the gas remains in the reservoir during the open-loop operation, then this could be considered as a carbon dioxide sequestration operation as well as geothermal operation (Luo et al., 2014). In some operations, this is the intent of using carbon dioxide as the working fluid (Stephens and Jiusto, 2010; Luo et al., 2014). In these carbon dioxide work fluid schemes, make-up carbon dioxide is added at surface to compensate for losses to the geothermal reservoir but the surface infrastructure does not discharge it to the atmosphere (Zhang et al., 2013).

Canada has also been moving forward towards geothermal energy harvesting opportunities. Majorowicz and Grasby (2010) examined from well data Canada’s temperature distributions at 3,500 and 6,500 m depth, respectively. The result of their work, shown in Figure 2.2, clearly indicates the potential of geothermal energy extraction in Canada. The highest temperature ~150 to 200°C is mainly found in western Canada, for example in parts of the Western Canada.
Sedimentary Basin (WCSB), the Mackenzie Foreland and Beaufort Basins (the sedimentary basins of northern Canada), and the Canadian Cordillera.

Figure 2.2: Temperature distribution of Canada at corresponding depth (Majorowicz and Grasby, 2010).
2.3. Enhanced Geothermal System (EGS) and Carbon Dioxide Sequestration

2.3.1. Hydraulic Fracturing of Enhanced Geothermal System (EGS)

Enhanced geothermal systems (EGSs) rely on using methods such as hydraulic fracturing, chemical stimulation, or CO$_2$ circulation to modify the reservoir permeability to achieve higher mobility of working fluid to improve fluid flow and heat recovery (Portier et al., 2009; Zhang et al., 2013). This concept was proposed by Los Alamos National Laboratory in the Hot Dry Rock (HDR) project in the late 1970s and early 1980s (Abraham, 2017). Hydraulic fracturing-EGS is the most common method since water is a cheaper heat carrier fluid medium. Hydraulic fracturing is a proven and well-matured technique with its first stimulation experiment treatment in 1947 in the Hugoton gas field in Grant County, Kansas conducted by Stanolind Oil (Montgomery and Smith, 2010). This method pumps fluid through a well into a formation faster than what the fluid can escape leading to a pressure rise in the formation which eventually exceeds the rock strength leading to dilation and cracking of the rock forming hydraulic fractures (Smith, 2015). The first hydraulic fracturing-EGS project was conducted at Rosemanowes Quarry in 1977 by the Camborne School of Mines (Jung, 2013). Since then, EGS projects have been developed across the world in Australia, Europe, Japan, United States, and United Kingdom as shown in Figure 2.3 (Pollack et al., 2020). However, due to the challenges such as water leaking, equipment failure at high temperatures, and temperature loss to surrounding rock, only a few projects are commercially active today (Abraham, 2017; Pollack et al., 2020).
Figure 2.3: 64 EGS projects around the world (Pollack et al., 2020).

2.3.2. Carbon Capture, Utilization, and Storage (CCUS) + Enhanced Geothermal System (EGS)

Despite Figures 1.1 and 2.3 showing many large-commercial scale geothermal energy plants and EGS projects and although Canada has operated geothermal projects since 1911, there are still only a few direct heat use projects that have been constructed to date (Government of Canada, 2021). Perhaps one option to incent greater deployment of geothermal energy plants could be to combine them with CO$_2$-EGS. CO$_2$-EGS is a concept that Brown (2000) proposed in 2000. On one side, geothermal reservoir is usually a high pressure and high temperature environment and
as such, carbon dioxide exists as supercritical condition (carbon dioxide critical temperature and pressure is at 31.06 °C and 7.39 MPa, respectively). Supercritical carbon dioxide (SCCO₂) has characteristics of both gas and liquid so it can full up all the pore space like a gas but flow like a liquid (Pan et al., 2017; Cabeza et al., 2017). SCCO₂ has better mobility than water in geothermal reservoirs due to its lower viscosity which enables larger mass flow rate than water under the same pressure drop and greater thermal extraction rate as described above in Section 2.1. With leakage of carbon dioxide into the geothermal reservoir, this becomes a benefit with respect to carbon dioxide credits. On the other hand, gas can be expected to have a greater expansion and compressibility than water which results a strong buoyancy force within a water or brine-filled aquifer. The lower viscosity of SCCO₂ means that it may take less power to lift it to surface in the production well than would be the case with water. A faster production rate means less heat losses to the surround rock when it rises up the production well. Thus, by conducing CO₂-EGS, both carbon dioxide loss and its lower viscosity benefit the process. Besides, Brown (2000) demonstrated that SCCO₂ will not dissolve minerals which means that no scale will be deposited in the well or surface facilities.

2.4. Offshore CO₂ sequestration Operation + Enhanced Gas Recovery (EGR)

Enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced geothermal systems (EGS) are considered as the most common opportunities for utilization in the oil and gas industries (Rafiee et al., 2019). Enhanced gas recovery (EGR) is a concept where injected carbon dioxide is used to aid production of methane from a natural gas reservoir to improve recovery; it has been studied for more than thirty-five years (Al-Hashami et al., 2005). When applied onto a
conventional gas reservoir, carbon dioxide acts as gas drive to restore formation pressure. On an unconventional gas reservoir, carbon dioxide might also work as a fracturing fluid leading to enhanced permeability in the reservoir (Zhou et al., 2022). Since not all of the injected carbon dioxide is produced back to surface during EGR, what remains in natural gas reservoir can be considered as stored within the reservoir. By this, CCUS can coexist with EGR. On the other hand, the geological structure of gas reservoir also has a benefit on doing CCUS, since the natural gas in place provides an estimate of the maximum gas storage capacities and caprock integrity, it will be safe to say that the risk of carbon dioxide leakage has low probability of happening (Oldenburg and Benson, 2001). According to Liu et al.’s (2022) review, global scale carbon dioxide storage capacity of conventional natural gas reservoirs is between 160 and 390 Gt and CO2-EGR can enhance natural gas recovery by 5 to 15% according to simulation studies.

Although in conventional dry gas reservoirs methane is the dominant component in natural gas, other hydrocarbons and inorganic gas such as C2H6, CO2, N2, and H2S, are also components in the gas (Liu et al., 2022). However, in deep systems where carbon dioxide is supercritical, SCCO2 has different physical properties compared with natural gas (Pan et al., 2017). As mentioned above, SCCO2 has both gas and liquid characteristics with both the density and viscosity of SCCO2 being significantly larger than that of CH4, as shown in Figure 2.4 (Oldenburg et al., 2001). Gravity segregation will occur between carbon dioxide and methane which causes the denser carbon dioxide to sink to the bottom of the reservoir leading to methane moving upwards for up-dip natural gas production. Furthermore, the relatively larger viscosity of SCCO2 will yield a favourable mobility ratio resulting in stable displacement of methane (Oldenburg and Benson, 2002; Al-Hashami et al., 2005).
Since 45% of the world's recoverable natural gas is assigned as unconventional and has contributed to ~60% of the growth in global gas supply (Gao and Li, 2016), unconventional natural gas reservoirs such as shale gas systems are good candidates for CO₂-EGR. A CO₂-EGR operation implemented on an unconventional natural gas reservoir not only has all the benefits listed above for a conventional natural gas reservoir condition but with one most important difference. In an unconventional system, the injected carbon dioxide can be used to hydraulically fracture the tight gas reservoir to improve the permeability of the reservoir. The gas-like characteristics of SCCO₂ allows it to have a higher surface volumetric injection rate into the formation (Al-Hashami et al., 2005).

The properties of SCCO₂ and methane suggest that there could be benefits for conducting CCUS plus EGR operations. Although this concept has been well studied, there are few commercial scale CO₂-EGR projects. In 2022, BP and the Tangguh LNG joint venture partnered on Indonesia’s first EGR along with CCUS development (BP Indonesia, 2022). By using reservoir simulation, it was demonstrated that methane recovery could be enlarged from 8 to 11% by using CO₂ injection and that CCUS as a means to enhance recovery could be viable option at the end of the reservoir life (Al-Hashami et al., 2005; Hussen et al., 2012; Khan et al., 2013). They also found that dissolution of CO₂ in formation water helps to delay CO₂ breakthrough (Al-Hashami et al., 2005; Hussen et al., 2012). In a reservoir simulation study on EGR with continuous injection of CO₂ into the reservoir, Schepers et al. (2009) found enhancement of natural gas recovery with about half of the total injected CO₂ remaining in the reservoir. For shale gas, Liu
et al. (2013) revealed that CO$_2$ injection has a limited effect on incremental CH$_4$ recovery (about 1%) but over 95% of the injected CO$_2$ being trapped.

![Density and Viscosity of CO$_2$ and CH$_4$](image)

**Figure 2.4: Density and viscosity of carbon dioxide and methane (Oldenburg et al., 2001).**

Unlike EGR projects, there are a few commercial CO$_2$-EOR project can be found in the public record (MIT, 2016). Melzer (2012) found that CO$_2$ retention in an EOR field project (after
captured and recycling of all produced CO$_2$) that more than 90% of the CO$_2$ remained within the reservoir. Compared to EOR projects, a reason for why there are few CO$_2$-EGR operations is due to the gap between crude oil and natural gas prices. However, regulations and policies in many nations now motivate carbon dioxide reduction, conversion, and sequestration activities (Jiang et al., 2020; Chen et al., 2022) together with carbon tax (Government of Canada, 2021), it is anticipated that CO$_2$-EGR opportunities will draw more attention for commercial development.

2.5. Offshore CO$_2$ Sequestration Operation

Offshore CCS project has been developed for decades. The world’s first offshore CCS plant can be traced back to 1996 which Equinor started in their Sleipner CCS project in the North Sea near Norway (Equinor, 1996; Ma et al., 2022). In the Sleipner site, approximately 1 million tonnes of carbon dioxide is captured and stored each year. Another carbon dioxide sequestration project that Equinor is pursuing is at the Snøhvit site in the Barents Sea (Equinor, 1996; Hansen et al., 2013; Furre et al., 2019). A large-scale offshore CCS operation is operating in Brazil where in one of their offshore oil production operations, carbon dioxide produced with oil is re-injected into the subsalt deposit (Rosa et al., 2018).

Due to the cost and difficulty of infrastructure, the number of large-scale commercial offshore CCUS project can still be counted on one hand. Project K12-B in the Netherlands and Tomakomai in Japan were operating in 2004 and 2016, respectively, and terminated in 2017 and 2019, respectively. Lula in Brazil and Enping in China were operating in 2011 and 2021, respectively, and are still operating now (Ringrose and Meckel, 2019; Li, 2022). Among all the
projects listed, only Lula in Brazil is operating under CO$_2$-EOR method in an ultra-deepwater field (Rosa et al., 2018). Other than Lula, the other projects are all pure offshore carbon dioxide sequestration projects. From analysis of the Sleipner and Snøhvit projects, Ringrose and Meckel (2019) concluded that several prospective offshore regions that have a cumulative storage capability of over 100 GtCO$_2$ with the global map of distribution and thickness of sediment accumulations over continental margins. There are six planned offshore CCS projects reported that will be conducted in the future, which are Northern Lights and Longship projects in Norway, Porthos project in the Netherlands, CarbonNet project in Australia, Acorn and Teesside projects in the UK, and Houston Ship Channel project in the US (Li, 2022).

Sequestration requires that one or more trapping mechanisms, including structural, residual, solubility, and mineral trapping, occur (Benson and Cole, 2008; Gislason et al., 2014). Physical trapping such as structural and residual trapping are not permanent solutions since the carbon dioxide is still mobile and not fixed in place and require a zero or very low permeability cap rock in a stable geological activity (Gislason et al., 2014). Otherwise, a fault (new or previously unknown) could lead to carbon dioxide leaking to above or below formations. However, offshore sequestration operation might not have the same risks as that of onshore sequestration since when the carbon dioxide reaches sea water, it will dissolve in the water and since the water is slightly heavier with dissolved carbon dioxide, it will tend to remain in place. However, this also will acidify this sea water leading to potential harm to marine life (Wu and Li, 2020).

Fortunately, chemical trapping such as solubilization and mineral trapping can permanently fix carbon dioxide. However, solubility and mineral trapping with gas phase carbon dioxide usually
needs thousands of years to occur before which there is opportunity for leakage of gas phase carbon dioxide from structural and residual trapping. Injection of dissolved carbon dioxide in the water directly into an aquifer removes the issue of gas phase buoyancy and could potentially yield more rapid mineralization but the amount of total material that has to be injected is high since only about 5% by mass would be carbon dioxide (Gislason et al., 2014; Kelemen et al., 2020; Gislason and Oelkers, 2014). However, for offshore application, seawater can be used. Snæbjörnsdóttir et al. (2020) showed that seawater can dissolve only slightly lower amounts of carbon dioxide than freshwater, as shown in Figure 2.5.

![Figure 2.5: CO₂ solubility in fresh water and seawater under different pressure (source from Snæbjörnsdóttir et al. (2020))](image)
Mineral trapping can be subdivided into two stages, as shown in Figure 2.6. First, continuous injection of gas phase carbon dioxide will gradually turn the formation environment acidic by following reactions (Xu et al., 2014):

\[
\text{CO}_2(g) + \text{H}_2\text{O} = \text{H}_2\text{CO}_3 \tag{2.5.1}
\]
\[
\text{H}_2\text{CO}_3 = \text{H}^+ + \text{HCO}_3^- \tag{2.5.2}
\]

![Figure 2.6: Mineral trapping steps of CO₂ sequestration](image)

Alkaline silicate mineral in the formation rock can undergo dissolution reactions which alter the formation environment pH. In dissolution, the reactions depend on the composition of formation rock. The alkalinity production reactions will yield carbonate mineral precipitation (Salek et al., 2013). These reactions occur with the cation from prior reactions of alkaline silicate mineral in the formation rock or aquifer that can react with CO₂. For example, a sandstone formation which could contain anorthite, K-feldspar, Fe–rich chlorite, and albite plagioclase will react with
carbon dioxide forming calcite and kaolinite or dawsonite as follows (Rochelle et al., 2004; Yanzhong et al., 2020; Pearce et al., 2022):

Anorthite:

\[
\text{CaAl}_2\text{Si}_2\text{O}_8 + \text{CO}_2 \text{(aq.)} + \text{H}_2\text{O} \leftrightarrow \text{CaCO}_3 \text{(calcite)} + \text{Al}_2\text{Si}_2\text{O}_5\text{(OH)}_4 \text{(kaolinite)} \quad (2.5.3)
\]

K-feldspar:

\[
\text{KAlSi}_3\text{O}_8 + \text{Na}^+ + \text{CO}_2 \text{(aq.)} + \text{H}_2\text{O} \\
\leftrightarrow \text{NaAlCO}_3\text{(OH)}_2 \text{(dawsonite)} \\
+ 3\text{SiO}_2 \text{(quartz/chalcedony/cristobalite)} + \text{K}^+ \quad (2.5.4)
\]

K-feldspar:

\[
\text{KAlSi}_3\text{O}_8 + \text{H}^+ + 0.5\text{H}_2\text{O} \leftrightarrow 0.5\text{Al}_2\text{Si}_2\text{O}_5\text{(OH)}_4 \text{(kaolinite)} + 2\text{SiO}_2 + \text{K}^+ \quad (2.5.5)
\]

Fe–rich chlorite:

\[
\text{Fe}_4\text{MgAl}_2\text{Si}_3\text{O}_{10}\text{(OH)}_8 \leftrightarrow 10\text{H}^+ \\
\leftrightarrow 4\text{Fe}^{2+} + \text{Mg}^{2+} + \text{Al}_2\text{Si}_2\text{O}_5\text{(OH)}_4 \text{(kaolinite)} + \text{SiO}_2 \text{(silica)} + 7\text{H}_2\text{O} \quad (2.5.6)
\]

Albite plagioclase

\[
\text{NaAlSi}_3\text{O}_8 + \text{CO}_2 + \text{H}_2\text{O} \leftrightarrow \text{NaAl(CO}_3\text{)(OH)}_2 \text{(dawsonite)} + 3\text{SiO}_2\text{(silica)} \quad (2.5.7)
\]

If the host formation is basalt rock, the mineral in-situ could be wollastonite, olivine, pyroxenes, serpentine polytypes, and brucite, and the reactions with carbon dioxide are as follow (Kelemen et al., 2020):

Wollastonite:
CaSiO$_3$) + CO$_2$ $\leftrightarrow$ CaCO$_3$  \hspace{1cm} (2.5.8)

Olivine:

Mg$_2$SiO$_4$ + 2CO$_2$ = 2MgCO$_3$ + SiO$_2$ \hspace{1cm} (2.5.9)

Pyroxenes:

CaMgSi$_2$O$_6$ + 2CO$_2$ = CaMg(CO$_3$)$_2$ + 2SiO$_2$ \hspace{1cm} (2.5.10)

Serpentine polytypes:

Mg$_5$Si$_2$O$_5$(OH)$_4$ + 3CO$_2$ = 3MgCO$_3$ + 2SiO$_2$ + 2H$_2$O \hspace{1cm} (2.5.11)

Brucite:

Mg(OH)$_2$ + CO$_2$ = MgCO$_3$ + H$_2$O \hspace{1cm} (2.5.12)

The dissolved bicarbonate ion (HCO$_3^-$) will react with divalent cations such as Ca$^{2+}$, Mg$^{2+}$ and Fe$^{2+}$ from the aquifer resulting in substantial trapping and immobilization of carbon dioxide and precipitate carbonate minerals (Gunter et al., 1997; Liu et al., 2019; Pearce et al., 2022) as follows:

Ca$^{2+}$ + HCO$_3^-$ $\leftrightarrow$ CaCO$_3$ (Calcite) + H$^+$ \hspace{1cm} (2.5.13)

Mg$^{2+}$ + HCO$_3^-$ $\leftrightarrow$ MgCO$_3$ (magnesite) + H$^+$ \hspace{1cm} (2.5.14)

5CO$_2$ + 5CaCO$_3$ + Mg$_5$Al$_2$Si$_3$O$_{10}$(OH)$_8$

$\leftrightarrow$ 5CaMg(CO$_3$)$_2$ (dolomite)

+ Al$_2$Si$_2$O$_5$(OH)$_4$ (kaolinite) + SiO$_2$ (silica) + 2H$_2$O \hspace{1cm} (2.5.15)

4Fe$^{2+}$ + Mg$^{2+}$ + 5HCO$_3^-$ = 5Fe$_{0.8}$Mg$_{0.2}$CO$_3$ (siderite) + 5H$^+$ \hspace{1cm} (2.5.16)
2.6. What is missing in the literature?

The literature review reveals that although there has been much research on EGS and CCUS and combinations of geothermal and CCS, there are still a lack of data and experience on turning those techniques into real large-scale commercial project. In this thesis, the focus is to bring out a detail analysis about EGS or CCUS performance based on the geology data of the real field recorded in Canada and China for contributing on GHG reduction activity. The research documented in this thesis are as follows:

1. With the proven geothermal potential in the Western Canada Sedimentary Basin (WCSB) and in particular in the Basal Cambrian Sandstone Unit (BCSU) in Alberta, a study on the potential for enhanced geothermal systems in this system has not yet been done.

2. Given that the Shell Quest CCS project is storing carbon dioxide in the BCSU, an exploration of the potential for geothermal heat recovery coupled with CCS has not yet been completed.

3. There are offshore gas production operations in the South China Sea but as yet, no one has evaluated SCCO$_2$ injection into these systems for sequestration of the carbon dioxide and enhanced production of methane.

4. There are no offshore CCS operations in the South China Sea at present but it appears to be a promising potential site for offshore storage of carbon dioxide to achieve China’s GHG emissions targets. As yet, an evaluation of the potential for CCS in a candidate subsea aquifer zone has not been done especially with focus on the ability of the system to mineralize the injected carbon dioxide.
In this thesis, the research consists of four studies – two in Canada and two in China. All have a basis in real geological/reservoir data obtained from public databases or from an industrial sponsor who shared the data.
CHAPTER 3: Investigation of Enhanced Geothermal System in the Basal Cambrian Sandstone Unit, Alberta, Canada

3.1. Introduction

Climate change has become a global threat that requires low greenhouse gas (GHG) energy systems. Since the Paris Agreement signed in 2015, there is an urgent requirement to move to low or zero or even negative GHG emission energy generation technologies. According to this agreement, Canada has committed to reduce GHG emissions by 30% below 2005 levels by 2030 and achieve a net-zero emissions by 2050 (Paris Agreement, 2015). The Government of Canada (2021) in 2021 claimed that it will invest more in its climate plan to ensure Canada exceeds its 2030 emissions reduction goals. Carbon neutrality or negativity are concepts that are being explored and developed to achieve these reduction goals. Neutrality is defined as the balance between emission and absorption of carbon from the atmosphere (Gössling, 2009; Freedman et al., 2009; Budinis et al., 2018; Tapia et al., 2018; Li and Elsworth, 2019). Options for neutrality or negativity include renewable energy sources such as solar, wind, geothermal, solar thermal, tidal and ocean thermal (Choi et al., 2017; Ericson et al., 2019; Saadawi, 2019). Here, we explore the potential for geothermal energy in Alberta. Historically, most of Alberta’s power was generate from coal-fired power plants but this has transitioned over the past decade to natural gas (Barst et al., 2017; Doluweera et al., 2020). However, even with natural gas fired power generation, there are significant GHG emissions.

The key issues that prevent full implementation of geothermal energy is its uncertain performance and relatively expensive cost (Ericson et al., 2019). Geothermal is classified as a
drillable underground asset with accessible thermal energy which can be harvested from the rock content with or without fluid flow through the rock (Tester et al., 2006). In traditional geothermal energy harvesting, cold fluid is pumped to the geothermal reservoir which is then heated producing hot fluid to the surface (Wang, K et al., 2018). As with all heat transfer processes, the performance of geothermal systems is sensitive to energy losses (Wang, H. et al., 2018). A high-grade geothermal resource for open-loop energy harvesting should have high temperature and natural heat flux, high permeability and porosity, sufficient fluids in place, and adequate fluids recharge (Tester et al., 2006). Since not all geothermal reservoirs have all these conditions, one or more unsatisfied conditions will lower the efficiency of geothermal energy harvesting. For example, hot dry rock (HDR) reservoirs which is found in the United States and China have high temperature with low permeability and porosity but no or nearly no fluids in place which makes it difficult to harvest the reservoir’s heat (Kelkar et al., 2016; Wang et al., 2018).

Canada has compelling geothermal energy harvesting opportunities. Majorowicz and Grasby (2010) found two main regions in Canada that have higher geothermal potential with temperatures over 150°C at about 3.5-6.5 km depth: the Western Canada Sedimentary Basin (WCSB) displayed in Figure 3.1 and the sedimentary basins of northern Canada (the Mackenzie Foreland and Beaufort basins). As shown by Rahmanifard (2019), exploitation of geothermal energy in Alberta will not only lower the emissions intensity of power generation but also can create economic benefits and jobs. Chong et al. (2021) did a case study focused on the Basal Cambrian Sandstone Unit (BCSU) in Alberta, Canada and examined two well and five well pattern systems for geothermal energy harvesting. They concluded that the five well pattern system has a higher efficiency, but it also has a lower energy produced per energy invested rate.
Furthermore, Chong et al. described that the flow resistance within geothermal reservoir is a constraint on energy harvesting efficiency. Thus, there is potential that reservoir stimulation via hydraulic fracturing could improve the energy recovery process (Häring et al., 2008; Yew and Weng, 2014; AbuAisha et al., 2016; Song et al., 2018). AbuAisha et al. (2016) in a study of Cheng et al. (2010) and Zhou et al. (2009) concluded that hydraulic fracturing can improve geothermal energy recovery. Here, an enhanced geothermal system (EGS) where hydraulic fracturing is used to stimulate the resource is examined to improve the harvesting of energy from the Basal Cambrian Sandstone geothermal reservoir.

![Temperature distribution of WCSB in Alberta Canada](image)

*Figure 3.1: Temperature distribution of WCSB in Alberta Canada (from Hofmann et al. (2014)).*
3.2. Model Description

The model was constructed from the surface to the Basal Cambrian Sandstone Unit (BCSU), which has depth equal to about 2,330 m. The model consists of an overburden (surface to BCSU), the BCSU, and then the Precambrian basement below the BCSU, as listed in Table 3.1. The properties of the BSCU was obtained from Ge et al. (1992), Weides et al. (2014) and Satter et al. (2016).

Table 3.1: Properties of geothermal model.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Overburden</th>
<th>Basal Cambrian Sandstone Unit</th>
<th>Precambrian Crystalline Basement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Depth of Top of Unit (m)</td>
<td>0</td>
<td>2330.2</td>
<td>2377.4</td>
</tr>
<tr>
<td>Average Thickness (m)</td>
<td>2330.2</td>
<td>47.2</td>
<td>422.6</td>
</tr>
<tr>
<td>Average Horizontal Permeability (mD)</td>
<td>-</td>
<td>1.9</td>
<td>-</td>
</tr>
<tr>
<td>Average Vertical Permeability (mD)</td>
<td>-</td>
<td>0.37</td>
<td>-</td>
</tr>
<tr>
<td>Average Porosity, fraction</td>
<td>-</td>
<td>0.1484</td>
<td>-</td>
</tr>
<tr>
<td>Average Compressibility (1/kPa)</td>
<td>-</td>
<td>3.63×10^(-6)</td>
<td>-</td>
</tr>
<tr>
<td>Average Heat Capacity (J/m^3°C)</td>
<td>2.50×10^6</td>
<td>2.50×10^6</td>
<td>2.50×10^6</td>
</tr>
<tr>
<td>Average Thermal Conductivity (J/m day°C)</td>
<td>2.68×10^3</td>
<td>2.68×10^3</td>
<td>2.42×10^5</td>
</tr>
</tbody>
</table>

3.2.1. Geological model

The model consists of a domain 1,000 m by 1,000 m in the horizontal directions and 2,800 m vertically, as shown in Figure 3.2. The target zone for geothermal energy harvesting is at depth 2,330 m in the BCSU with thickness ~47 m and initial temperature 99.8°C (Hofmann et al., 2014). In the BCSU, Chong et al. (2021) used constant properties with 1.9 mD of horizontal
permeability, 0.37 mD of vertical permeability, and 14.84% of porosity. Here, in the BCSU, the horizontal and vertical permeabilities and porosity are uniformly randomly distributed with same mean values as that of Chong et al. (2021). The variation around the mean values is 15% (this was guided by the variability of the porosity and permeability data from several wells in the BCSU). Although not linked to any specific geologic features of the reservoir, a uniformly distributed random distribution of porosity and permeabilities provides a simple approximation for representing heterogeneity of the geothermal reservoir. Figure 3.2 also displays a horizontal plane (in the plane of the wells) illustrating the heterogeneity of the porosity.
Figure 3.2: Three-dimensional (3D) model domain (top) and visualization of grid and porosity in the horizontal plane containing the wells in the target layer with variable porosity distribution shown (bottom).
3.2.2. Grid and Conservation Equations

The domain is discretized into grid blocks as shown in Figure 3.2. The domain is divided into fifty 20 m grid blocks in both horizontal directions and a variable grid in the vertical direction. Above the BCSU, the domain is divided into 106 grid block layers. For the BCSU, the dimensions of the grid blocks is equal to 1.048 m vertically with 2.86 m extent in the cross-well direction. In the region surrounding the hydraulic fracturing port, the grid is refined to 4 m in the down-well direction. The total number of grid blocks in the model is 1,323,000.

The thermal reservoir simulation CMG STARS™ (2022) is used in this study for simulating the hydraulic fracturing operation as well as the geothermal operation. STARS™ is a commercial thermal reservoir simulation software package that models multiphase flow and heat transfer in porous media. More details of its formulation can be found in its user manual (CMG, 2022). In the geothermal system, the only fluid in the rock is water (either as liquid or vapour).

Within each grid block, the material balance is given by (Pruess and Narasimhan, 1985; CMG, 2022; Chong et al., 2021):

$$\frac{\partial (V_v \rho)}{\partial t} = -\nabla \cdot (\rho \mathbf{u}) + q$$  (3.1)

where $V_v$ is void volume, $\rho$ is mass density of water, $t$ is time, $\mathbf{u}$ is the velocity vector, and $q$ is net flow from external sources. The velocity is given by Darcy’s Law:

$$\mathbf{u} = -\frac{k}{\mu} (\nabla P - \rho g \nabla z)$$  (3.2)
where \( k \) is absolute permeability of the rock, \( \mu \) is the water viscosity, \( P \) is pressure, \( g \) is the gravity acceleration and \( z \) is depth. For each grid block, the energy conservation equation is given by:

\[
\frac{\partial}{\partial t} (V_v \rho U + V_s \rho_s C_s T) + \nabla \cdot (\rho u H) - \nabla \cdot (k_T \nabla T) = q_c - q_L
\]  

(3.3)

where \( U \) is specific internal energy of water, \( V_v \) is rock volume, \( \rho_s \) is rock density, \( C_s \) is rock’s specific heat capacity, \( T \) is temperature, \( H \) is the enthalpy of the water, \( k_T \) is total effective thermal conductivity, \( q_c \) is heat sources and \( q_L \) is heat losses to overburden and underburden.

The conservation equations are applied in each grid block and due to the connections between neighboring grid blocks, a system of coupled discretized non-linear equations are derived. These discretized equations are solved at each time step by using Newton’s method and an implicit time integrator (CMG, 2017). To constrain mass balance errors to less than 0.001\%, the convergence criterion for both nonlinear and linear solvers is set to \( 1 \times 10^{-6} \).

### 3.2.3. Boundary and Initial Conditions

For the side boundaries, an aquifer model (Carter and Tracy, 1960; CMG, 2017) is applied for water flow between the surroundings and the model. At these boundaries, heat transfer symmetry boundary conditions are imposed. For the bottom boundary, no water flow condition is imposed and the temperature is set equal to 106.53°C, consistent with the geothermal gradient. At the top boundary, no fluid flow is imposed and a heat loss model (Vinsome and Westerveld, 1980;
CMG, 2017) is used for heat loss to the atmosphere (atmosphere temperature is taken to be 16.85°C).

For initial conditions, the domain has a pressure distribution consistent with the hydrostatic pressure gradient. In the target zone, the pressure is equal to about 30 MPa. For temperature, the system has a linear temperature profile from the top boundary to the bottom according to the boundary conditions.

### 3.2.4. Fracture Dilation-Recompaction model

To model the natural fractures within the porous matrix, a dual porosity approach is used (Ge et al., 1992). The natural fracture spacing is set equal to 50 m in the horizontal directions. The natural fracture porosity and permeabilities have mean values equal to 8.4% and 19 mD in the horizontal directions and 38 mD in the vertical direction with a random uniform distribution with values ±15% of the mean values as described above.

To model the enhancement of porosity and permeability when the system undergoes hydraulic fracturing, the dilation-recompaction model given by Beattie et al. (1989), often referred to as the quad model, illustrated in Figure 3.3 is used (Beattie et al., 1989; Cokar et al., 2012; Bao et al., 2016). In this model, the porosity depends on the pressure according to:

\[
\phi = \phi_{ref} e^{[G_0(P-P_{ref})]}
\]  

(3.4)
where \( \phi \) is real-time porosity, \( \phi_{\text{ref}} \) is initial porosity, \( c_0 \) is formation compressibility, \( P \) is real-time pressure, and \( P_{\text{ref}} \) is initial pressure. The permeability depends on the porosity as follows (Bao et al., 2016; Huang et al., 2016):

\[
k = k_0 e^{k_{\text{mul}} \left( \frac{\phi - \phi_0}{1 - \phi_0} \right)}
\]

where \( k \) is the (dilated) permeability, \( k_0 \) is the initial permeability, and \( k_{\text{mul}} \) is a parameter governing how sensitive the permeability is to the change of porosity.

Here, the initial pressure of the BCSU is equal to \(~\)30 MPa. The recompaction pressure is set to be equal to 35 MPa. Based on similarly deep reservoirs, the pressure at which the rock in the BCSU hydraulically fractures is equal to about 50 MPa. The residual dilation fraction is defined as \( B/A \) (see Figure 3.3) and here is taken equal to \( f_R = 0.5 \). It indicates how much total dilation in the rock is permanent and unrecoverable (\( f_R = 1 \) indicates that pore volume increased from dilation is maintained whereas \( f_R = 0 \) means it will diminish completely (Weides et al., 2014; CMG, 2017)). The quad model with the parameters used here is shown in Figure 3.4. The formation compressibility after dilation (fracturing, line bc in Figure 3.3) is set at 10 times larger than the original formation compressibility (line ab indicating the elastic response). The permeability multiplier for the matrix is set equal to 10 for the horizontal directions and 55 for the vertical direction. For the natural fractures, they are set at 5 for the horizontal directions and 20 for the vertical direction. As shown below in the results, these multipliers generated enhancement of the horizontal and vertical permeabilities that are consistent with field evidence.
(Lianbo and Xiang-Yang, 2009; Zimmerman et al., 2010; Zimmerman et al., 2011 Zimmerman et al., 2019) for hydraulic fracturing operations.

Figure 3.3: Reservoir deformation model (Beattie et al., 1989). $P_{\text{dilation}}$ is pressure at which fracturing starts. The ratio of B to A is referred to as the residual dilation fraction (the irreversible amount of dilation due to fracturing).

Figure 3.4: Dilation-recompaction model for hydraulic fracture porosity behaviour.
3.2.5. Well Configuration and Wellbore Flow/Heat Transfer Model

In this study, we examine how a hydraulic fracturing operation followed by open loop geothermal energy recovery compared to non-stimulated geothermal energy harvesting. The geothermal system consists of two horizontal wells (one injection and one production) which are placed in the center of target zone as displayed in Figure 3.2. Both well are hydraulically fractured with 8 stages performed on each well. The open ports of both wells are the 8 hydraulically fractured stages as shown in Figure 3.2 (i.e., flow is only allowed out from or into the port locations).

Flow (liquid flow rate and pressure drop) within the wells is modelled by using the semi-analytical model (SAM) available in STARS™ based on Oballa et al. (1997) (Fontanilla and Aziz, 1982; CMG, 2017). Table 3.2 lists the properties of the materials and dimensions in the wellbores. In SAM, the pressure drop in the well depends on viscous drag, inertia, and gravity. Under turbulent flow, the frictional pressure gradient is determined by:

\[
\frac{\partial p}{\partial x} = \frac{2f \bar{u}^2}{D \rho}
\]  

(3.6)

where the friction factor \( f \) is determined from Colebrook’s equation (Colebrook et al., 1939), \( D \) is diameter of the tubing string, \( \bar{u} \) is the average fluid speed, and \( \rho \) is fluid density. The roughness of the internal wall of the well pipe is set equal to 0.0001.
Heat transfer between each grid block containing the well and the well itself is modelled by using a one-dimensional series radial heat transfer model with heat transfer resistances arising from the cement, casing, annulus space, insulation layer, and tubing string wall, as described by Chong et al. (2021). The heat transfer coefficient at the tubing string wall is determined by the method described by Fontanilla and Aziz (1982).

Table 3.2: Wellbore material properties (Chong et al., 2021).

<table>
<thead>
<tr>
<th>Object</th>
<th>Dimensions</th>
<th>Material</th>
<th>Thermal Conductivity, W/m°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing</td>
<td>Inner diameter 0.163 m, Outer diameter 0.168 m, Roughness 0.0001</td>
<td>Carbon steel</td>
<td>44.96</td>
</tr>
<tr>
<td>Insulation</td>
<td>Outer diameter 0.173 m</td>
<td>Calcium Silicate</td>
<td>0.03</td>
</tr>
<tr>
<td>Casing</td>
<td>Outer diameter 0.23 m</td>
<td>Carbon steel</td>
<td>44.96</td>
</tr>
<tr>
<td>Annulus</td>
<td>Outer diameter 0.245 m</td>
<td>Water</td>
<td>0.66</td>
</tr>
<tr>
<td>Cement</td>
<td>Outer diameter 0.3 m</td>
<td>Cement</td>
<td>0.35</td>
</tr>
</tbody>
</table>

3.2.6. Operating Conditions

Water was chosen as the working fluid in this study following insights obtained from Zimmermann et al. (2010; 2011; 2019). During the hydraulic fracturing operation, for each stage, both wells injected a total of 14,400 m³ of fluid into the reservoir (this volume accounts for the proppant as well as fluid). The ability of the proppant to hold open the fractures is modelled with the quad model, described above, with the residual dilation fraction equal to 0.5. At each well, each stage is done sequentially one after the other until all 8 stages are complete. After hydraulic fracturing has finished, geothermal operations commence with water at 16.85°C injected through
the injection well at 200, 400, or 600 m$^3$/day with the production well set with a minimum bottom-hole pressure equal to 9 MPa. The total operation time for geothermal energy harvesting is set equal to 30 years. To determine the impact of hydraulic fracturing, three models were also run at 200, 400, or 600 m$^3$/day with no hydraulic fracturing treatment.

3.3. Results and Discussion

3.3.1. Pressure and permeability distributions during and after hydraulic fracturing

Figure 3.5 shows the pressure distribution within the reservoir in the horizontal plane of the injection and production wells after each hydraulic fracturing stage. The results show that in each stage at the injection port, the pressure peaks at about 40 MPa. The pressure does not persist at the peak injection pressure after each stage due to fluid leak-off beyond the fracture zone.

Figure 3.6 illustrates the pressure, porosity, and vertical permeability changes at the grid block adjacent to the port for the second stage of hydraulic fracturing (the horizontal permeability exhibits similar results). The other ports show similar results for both the injection and production wells. The profiles show that as the pressure climbs rapidly, so too does the porosity and permeability. As soon as the pressure reaches the dilation (fracture) pressure of 50 MPa, the porosity and consequently, the permeability, rises rapidly as per the quad model described above. After injection stops, the pressure stops climbing and due to leak-off, the pressure declines. The porosity-pressure tractor falls along the elastic recompaction curve (see Figure 3.4, line cd, and
Figure 3.5) and the porosity and permeability drops. However, the porosity and permeability are irreversibly increased due to the process of fracturing. The results reveal that after hydraulic fracturing and recompaaction of the fracture after injection has stopped, the vertical permeability is enhanced by up to five times its original value. This enhancement of the permeability is similar to those determined by Zimmermann et al. (2010; 2011; 2019) for hydraulic fracture operations.

**Figure 3.5**: Pressure distribution in reservoir after each hydraulic fracturing stage (in the plane of the horizontal wells).
Figure 3.6: Changes of the pressure, porosity, and vertical permeability for grid block adjacent to the second stage hydraulic fracturing port.

3.3.2. Geothermal Injection-Production Performance

Figure 3.7 displays the production-injection performance for the hydraulic fracturing and non-fracturing cases. The result show that the production rate is not equal to the injection rate for all cases. This is because the reservoir, even after hydraulic fracturing, has sufficiently high flow resistance and fluid leak-off from the domain so that the production rate is lower than the injection rate. As expected, the results reveal that hydraulic fracturing lowers the resistance to flow (by raising the permeability in the reservoir) enabling greater flow rate of fluids through
and from the reservoir. However, even with hydraulic fracturing, the production flow rate never reaches the injection rate.

**Figure 3.7:** Average injection and production performance of all hydraulic fracturing and non-fracturing cases.

Figure 3.8 displays the bottom-hole temperature (BHT) at the production well heel as well as the produced surface temperature (PST) for both hydraulic fractured and non-fractured cases. During hydraulic fracturing, a large amount of cool fluid is injected into the reservoir. This cools the near-well regions surrounding the wells. This means that when geothermal energy production starts, in the hydraulically fractured cases, the BHT at the start of production is lower than that of the non-fracturing cases. However, depending on the injection rate and due to the geothermal heat flux from below the BCSU, the BHT at the wells eventually recovers. For the non-fractured case, there is a lag time between injection and production of fluids: the higher the injection rate,
the shorter is the lag time. This lag time does not occur in the hydraulically fractured cases. A comparison of the results show that the surface production temperature from the hydraulically fractured cases is higher than that of the non-fractured cases. For the non-fractured cases, it can be seen that heat losses are relatively large given the temperature differences between the BHT and PST. This temperature difference is lower in the hydraulically fractured cases. The production temperatures tend to be between 75 and 85°C depending on the injection flow rate which suggests that the BCSU would be most appropriate for district heating or for electricity generation using an organic Rankine engine.

![Graph showing production well heel bottom-hole temperature and produced surface temperature for hydraulic fractured and non-fractured cases.](image)

**Figure 3.8:** Production well heel bottom-hole temperature (solid lines) and produced surface temperature (dashed lines) of hydraulic fractured and non-fractured cases.
Figure 3.9 displays temperature distributions in the plane of the horizontal wells through time for all of the cases. The results show that as the geothermal operation evolves, the injected fluid cools the geothermal reservoir and that the chilled region grows towards the production well. Furthermore, the natural geothermal heat flux from below the system is not sufficient to replenish the heat being removed from the reservoir by the circulating fluid. As expected, the greater the injection flow rate, the faster is the heat depletion from the reservoir.
Figure 3.9: Temperature (°C) distribution for the cases with and without hydraulic fracturing at different injection rates in the plane of the horizontal wells.
Figure 3.10 displays the temperature of the produced water from the reservoir in the horizontal well (surface to 2300 m is the vertical section and the remainder is the horizontal portion of the well) after 5 and 30 years of operation. The results show that the higher the flow rate and the later in the operation, the lower the temperature of the fluid produced from the reservoir into the well. The temperature drop in the vertical section of the wells due to heat losses from the well to the surrounding rock is most significant at the lower flow rates. This is because the flow is relatively slow with greater residence time in the vertical section of the well and thus, there is more opportunity for heat losses. The higher the flow rate, the lower is the heat losses from the fluid.

![Non-Hydraulically Fractured Cases](image)

![Hydraulically Fractured Cases](image)

**Figure 3.10:** Water temperature along the production wellbore at 5 years and 30 years under different injection rate cases (surface to 2300 m is the vertical section and the remainder is the horizontal portion of the well).
Figure 3.11 displays the amount of energy invested and energy produced for the hydraulically fractured and non-fractured cases. The energy invested includes the energy of pumping the working fluid (water) through the target geothermal layer and back to the surface. The energy produced is the enthalpy of the produced fluid at the surface relative to the injected fluid. In the analysis conducted here, the energy associated with hydraulic fracturing operation is not counted in the EPEI (we treat it as the energy required for drilling and completing the well which is also ignored in the non-fractured cases). The results show that the amount of energy harvested in the hydraulically fractured cases is higher than that of the non-fractured cases. However, the amount of energy produced is also higher in the hydraulically fractured cases (due to the stimulation) but the increase is significant at low flow rate (at 200 m³/day injection rate, enhancement is 23.6%) whereas it is small at larger flow rate (at 600 m³/day injection rate, enhancement is 4.2%). The higher values of the produced and invested energy in the hydraulically fracturing cases is due to the lower resistance for circulating the working fluid through the geothermal circuit which results in higher produced fluid rate as well as the slightly higher temperature obtained.
Figure 3.11: Cumulative energy produced and invested for hydraulic fractured and non-fractured cases.
The thermal efficiency of the geothermal operation is reflected by the ratio of the Energy Produced to the Energy Invested (EPEI), also known also as the coefficient of performance (Hall et al., 2009). Figure 3.12 display the EPEI ratios versus time for all cases in both hydraulic fracturing and non-fracturing cases. As Chong et al. (2021) described, the geothermal reservoir is considered as exploitable when the EPEI exceeds 3 (GJ/GJ). Since all cases are higher than 3, all cases could be considered as exploitable energy production systems. The results show that the greater the injection rate, the higher is the EPEI profile. The results also show that the hydraulic fracturing simply accelerates the production of energy and that the benefit of using hydraulic fracturing is observed only over the early stages of the process. Eventually, all profiles for the hydraulic fractured and non-hydraulic fractured cases tend to the same ultimate value. For the 200 m$^3$/day cases, the EPEI profile is greater for the hydraulic fractured case over that of the non-fractured case for ~21 years. For 400 and 600 m$^3$/day injection rates, these times intervals are ~10 and ~6 years, respectively. Thus, the higher the injection rate, the more limited is the benefit of the hydraulic fracturing operation from an EPEI point of view.
Figure 3.12: Energy produced to energy invested (EPEI) ratio vs time for all hydraulic fracturing and non-fracturing cases.

3.4. Conclusions

In this work, hydraulic fracturing prior to open-loop geothermal production has been examined for application in the Basal Cambrian Sandstone Unit geothermal reservoir (~2330 m depth) in Alberta, Canada. The results demonstrate that both hydraulically fractured and non-fractured systems are capable of realizing greater energy produced than energy invested. The results show that the energy produced versus energy invest ratio tends to be greater than 5 for most of the operations considered here. However, the benefit of hydraulic fracturing mainly contributes to greater production of energy due to easier flow within the reservoir enabling higher production
rates especially in the early stages of the process. The results show that hydraulic fracturing acts to accelerate geothermal energy production but eventually the performance is similar to that of the non-hydraulically fractured cases. The results bring into question whether hydraulic fracturing of geothermal systems will help and whether they would provide economic benefits given the costs of hydraulic fracturing stimulation. One option might be to consider re-fracturing the reservoir at some later point of time to potentially further enhance geothermal heat recovery. Another would be to stop geothermal heat harvesting for a period of time to allow the natural geothermal heat flux to replenish the reservoir.
CHAPTER 4: Combined Geothermal and CO\textsubscript{2} Sequestration in the Basal Cambrian Sandstone unit in Alberta, Canada

4.1. Introduction

Over the past couple decades, there is growing concern with respect to the rise of greenhouse gas (GHG) concentrations in the atmosphere and as such, many nations have made commitments towards lowering their GHG emissions. These emissions arise from human activities including energy, transportation, agriculture, and industry (in all its processes and products). For example, Canada has committed in the Paris Agreement (2015) to reduce GHG emissions by 30% below 2005 levels by 2030 and achieve a net-zero emissions by 2050. And carbon price for Canada (Government of Canada 2021, 2022) will increase from $50 to $170 since 2022 to 2030. Climate change, and its consequences, present a clear threat which must be solved. The key challenge is that GHG emission reduction or elimination solutions, including renewable energy, nuclear energy, direct air or other carbon dioxide capture, utilization, and carbon dioxide sequestration in underground porous rock formations, present new capital costs and deployment issues given their requirements for infrastructure and social acceptability due to placement of new infrastructure or perceived dangers or unintended consequences of the new infrastructure. There is a need to find solutions for low or zero or even negative GHG emission energy generating technologies that are socially acceptable.

Over the past few decades, recent progress in the literature reveals that general approaches have evolved with respect to reduction of GHG emissions including capture of CO\textsubscript{2} from a process
operation (e.g. manufacturing, refining, etc.) with consequent utilization or sequestration and renewable power such as hydro, solar, wind, and geothermal, and nuclear power. Carbon capture, utilization, and storage (CCUS) is a broad concept to achieve emission reductions of processes to avoid that CO$_2$ is released to the atmosphere and will be a key and necessary technology for decarbonising industry sectors (Budinis et al. 2018, Bui et al. 2018). CO$_2$ injection for enhanced oil or gas recovery (EOR or EGR) is one CCUS concept (Lackner et al. 2003, Benson et al. 2008, Li et al. 2019, Iddphonce et al. 2020, Eliebid, 2017). In EGR, for example, since shale gas is methane trapped within natural fractures and intergranular porosity or sorbed onto or dissolved in organic matter, this methane could be replaced by CO$_2$ leading to large potential storage capacity while producing methane (Curtis, 2002). Shale gas recovery supported by CO$_2$ injection is a dynamic displacement process between CO$_2$ and CH$_4$ caused by the pressure gradient and competitive adsorption (Huo et al. 2017, Mohagheghian et al. 2019). With CO$_2$ injection for enhanced shale gas recovery technology, it can yield a closed cycle for CO$_2$ since the amount of CO$_2$ generated from methane combustion could be sequestered within the shale formation (Klewiah, 2020). If greater amounts of CO$_2$ are sequestered, then the process could be a negative carbon dioxide energy generating process.

options, their technologies and associated infrastructure are getting more mature with lower development cost with time (Ericson et al. 2019).

Enhanced geothermal systems (EGS) traditionally hydraulically fracture the aquifer to enhance its permeability prior to the geothermal operation (Li et al. 2015). CO$_2$ fracturing of the reservoir could also be done (CO$_2$-EGS) as suggested by Brown (Brown et al. 2000) where water is replaced by supercritical CO$_2$ as the working fluid in the EGS operation. Supercritical CO$_2$ behaves like gas in that it is space-filling but has density more like that of a liquid (Cabeza et al. 2017) and at a given permeability, supercritical CO$_2$ has higher mobility than that of water and thus it can potentially yield greater heat recovery than that of water-based EGS. Pruess (2006) report on experimental results where supercritical CO$_2$ achieved ~3.7 times larger mass flow rate and ~50% greater thermal extraction rate under high temperature and pressure condition (200°C and 51 MPa) than that of water.

Pruess (2006), using modelling of a five-spot pattern, report on the performance of enhanced geothermal systems using CO$_2$ as the working fluid demonstrating that CO$_2$ extracts more heat from hot fractured rock than that of water. Pruess also examined the potential for CO$_2$ storage due to loss of the CO$_2$ injected into the geothermal reservoir and reported on the results of the Fenton Hill, New Mexico experimental test site which demonstrated CO$_2$ losses of 7-12% into the reservoir which then opens the possibility of CO$_2$ geologic storage while producing geothermal energy (Duchane 1993). Randolph and Saar (2011) examine the case of coupling CO$_2$ sequestration with geothermal heat extraction using a symmetry model of a five-spot well configuration. Their results show that the combination of geothermal heat extraction with CO$_2$
sequestration provides a significant improvement of the economics of CO₂ sequestration. Mohan et al. (2015) examined the integration of a coal-fired integrated gasification combined cycle plant with an enhanced geothermal system that combines geothermal heat extraction with CO₂ sequestration. They examined the case where the geothermal reservoir has temperature 200 or 300°C. Their results show that the geothermal energy recovered benefits the process but that a substantial reservoir volume (>1 km³) is required for sufficient energy production over a process life of 25 years. Sun et al. (2016) explored CO₂ geological storage operated together with geothermal heat production where the produced fluid is water. They analyzed this operation in the Huizhou Sag located in the North of the Pearl River Mouth Basin in China. This CO₂-rich natural gas system is offshore where the water depth is about 200 m and the depth of the top surface of this system is between 3,000 and 5,000 m with maximum thickness 2,000 m. Their simulation results of a symmetry model of a five-spot well configuration (with well separation between injector and producer equal to 2,828 m) demonstrate that CO₂ breakthrough occurs between 2000 and 3500 days depending on the CO₂ injection rate. They conclude that the combined process demonstrates benefits over that of conventional geothermal processes. Wang et al. (2018) studied a CO₂-based enhanced geothermal system with CO₂ sequestration. Their results show that the CO₂-based system exhibited greater heat extraction than a water-based system. Coupled with CO₂ losses within the geothermal reservoir, the system achieves a certain amount of CO₂ sequestration. Wang et al. (2019) examined a CO₂-based enhanced geothermal system in a three-spot co-linear models (central injector with two producers at sides) at Soultz-sous-Forêts in the central Upper Rhine Graben hot dry rock geothermal reservoir at a depth of 4,000 and 5,000 m (185 and 200°C, respectively). The well separation between the injection and production wells is 650 m. Their results show that the higher the injection rate of CO₂, the better
is the performance of the system with respect to both CO$_2$ sequestration and heat extraction. Chen et al. (2021) used response surface models, conditioned to results from the NUFT code, to examine CO$_2$ sequestration and circulation in a relatively thin North Oman geothermal system consisting of a dipped geothermal reservoir with a vertical fault. Their results show that there is potential benefit for combined CO$_2$ sequestration and geothermal heat recovery in these reservoirs. In all of the studies listed above, the work required to compress the CO$_2$ for injection into the geothermal reservoir is not taken into account within the overall energy balance.

At this point, examination of combined geothermal heat extraction and CO$_2$ sequestration in deep systems using a horizontal well system with wellbore hydraulics, heterogeneity of the geothermal reservoir, with avoidance of production of the injected CO$_2$ to the surface has not been examined. Here, we explore a new concept to obtain GHG-negative emissions energy generation by applying a combination of geothermal and CO$_2$ sequestration where CO$_2$ injection is used to displace hot aquifer water to a production well to surface and the injection strategy is conducted so that the CO$_2$ is retained in the aquifer.

**4.2. Model Description**

Canada has compelling geothermal energy harvesting opportunities. The Western Canada Sedimentary Basin, displayed in Figure 4.1, and the sedimentary basins of northern Canada (the Mackenzie Foreland and Beaufort basins) have been found to have higher geothermal potential with temperatures over 150°C at reasonable depths (Majorowicz et al., 2010). However, for a combined geothermal and CO$_2$ sequestration process, the goal is to find the balance for CO$_2$
storage which implies large pore volume and ability to inject CO$_2$ and build up pressure so as to produce hot water to the surface. We explore the application of a combined geothermal and CO$_2$ sequestration process in the Basal Cambrian Sandstone Unit (BCSU) in Alberta, Canada (Shi et al., 2023).

Figure 4.1: Temperature distribution of the Western Canadian Sedimentary Basin in Alberta Canada (from Hofmann et al., 2014).
Starting in 2011, Shell has conducted a CO$_2$ sequestration operation in the BCSU referred to as the Shell Quest project. According to Shell (2011), they compress CO$_2$ at surface to about 10 MPa achieving a bottom-hole pressure of order of 31 and 32 MPa (due to hydrostatic head).

The model was constructed from the surface to the Basal Cambrian Sandstone Unit (BCSU), which has depth equal to about 2,330 m. The model consists of an overburden interval (surface to BCSU), the BCSU itself, and then the Precambrian basement below the BCSU, as listed in Table 4.1. The properties of the BSCU were obtained from Weides et al. (2014), Satter et al. (2016), and Ge et al. (1992).

<table>
<thead>
<tr>
<th>Unit</th>
<th>Overburden</th>
<th>Basal Cambrian Sandstone Unit</th>
<th>Precambrian Crystalline Basement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Depth of Top of Unit (m)</td>
<td>0</td>
<td>2,330.2</td>
<td>2,377.4</td>
</tr>
<tr>
<td>Average Thickness (m)</td>
<td>2,330.2</td>
<td>47.2</td>
<td>422.6</td>
</tr>
<tr>
<td>Average Horizontal Permeability (mD)</td>
<td>-</td>
<td>1.9</td>
<td>-</td>
</tr>
<tr>
<td>Average Vertical Permeability (mD)</td>
<td>-</td>
<td>0.37</td>
<td>-</td>
</tr>
<tr>
<td>Average Porosity, fraction</td>
<td>-</td>
<td>0.1484</td>
<td>-</td>
</tr>
<tr>
<td>Average Compressibility (1/kPa)</td>
<td>-</td>
<td>3.63×10$^{-6}$</td>
<td>-</td>
</tr>
<tr>
<td>Average Heat Capacity (J/m$^3$°C)</td>
<td>2.50×10$^6$</td>
<td>2.50×10$^6$</td>
<td>2.50 × 10$^6$</td>
</tr>
<tr>
<td>Average Thermal Conductivity (J/m day°C)</td>
<td>2.68×10$^3$</td>
<td>2.68×10$^3$</td>
<td>2.42 × 10$^3$</td>
</tr>
</tbody>
</table>

**4.2.1. Geological model**

The geothermal aquifer model consists of a domain with 10,000 m x 1,000 m horizontally and 2,800 m vertically, as shown in Figure 4.2. The initial temperature in the BCSU is equal to
99.8°C (Hofmann et al., 2014). In the BCSU, the average horizontal and vertical permeabilities are 1.9 and 0.37 mD, respectively, and 14.84% average porosity (Shi et al., 2023). To model the natural fractures within BCSU, a dual porosity approach is used (Ge et al., 1992). The natural fracture spacing is set equal to 50 m in the horizontal directions with mean porosity and permeabilities equal to 8.4% and 19 mD in the horizontal directions and 38 mD in the vertical direction.

The thermal reservoir simulator CMG STARS™ (2022) is used in this study for simulating the injection of CO₂ into the target unit as well as the production of geothermally hot water from the formation. STARS™ is a commercial thermal reservoir simulator that models multiphase flow and heat transfer in porous media. More details of its formulation can be found in its user manual (CMG, 2022). In STARS™, the domain is discretized into grid blocks as shown in Figure 4.2. The domain is divided into fifty 200 m grid blocks in the downflow direction and fifty 20 m grid blocks in the crossflow direction and a 106 grid blocks with variable dimensions in the vertical direction. A grid sensitivity (halving the grid in all directions) demonstrated that the results were independent of the grid block dimensions. For the BCSU, the dimensions of the grid blocks have dimensions equal to 5.9 m vertically and 20 m extent in the crossflow direction. Each grid block has its own properties. The total number of grid blocks in the model is 265,600. In the geothermal system, initially, the only fluid in the rock is liquid water.
Figure 4.2: Three-dimensional (3D) model domain. The horizontal injection well is positioned at the top of the BCSU whereas the horizontal production well is located at the bottom of the BCSU.

Figure 4.3 displays a horizontal plane in the plane of the injection and production wells. To account for geological variability in the BCSU, variations of 15% around the mean values of the porosity and horizontal and vertical permeabilities (uniformly distributed) are applied in all grid blocks in the BCSU.
Figure 4.3: Illustration of grid and porosity in the horizontal plane containing the injection well (left) at top of the target layer and production well (right) at bottom of the target layer. The spacing between the injection and production wells is 6,000 m. The length of the horizontal wells is 800 m.

4.2.2. Grid and Conservation Equations

The mass balance for each component $j$ in the water-gas system is given by (CMG, 2022; Pruess, 1985):

$$
\frac{\partial}{\partial t} \left[ \phi \left( \frac{x_{wj} \rho_w S_w}{MW_w} + \frac{x_{gj} \rho_g S_g}{MW_g} \right) \right] + \frac{m_j - m_j^r}{MW_j} = \nabla \cdot \left[ \frac{k_w \rho_w}{\mu_w} c_{wj} (\nabla P_w - \gamma_w \nabla z) + D_{wj}^{\text{eff}} \nabla \left( \frac{\rho_w x_{wj}}{MW_w} \right) \right]$$

$$+ \frac{k_g \rho_g}{\mu_g} c_{gj} (\nabla P_g - \gamma_g \nabla z) + D_{gj}^{\text{eff}} \nabla \left( \frac{\rho_g y_j}{MW_g} \right)$$

(4.1)

where $\phi$ is porosity, $x_{wj}$ is mole fraction of component $j$ in water phase, $\gamma_j$ is the mole fraction of component $j$ in the vapour phase, $\rho_*$ is density of phase $*$, $S_*$ is the saturation of phase $*$, $MW_*$ is the molecular weight of phase $*$, $k_*$ is the effective permeability of phase $*$, $\mu_*$ is the viscosity of phase $*$, $c_{*j}$ is the compressibility of component $j$ in phase $*$, $P_*$ is the pressure of phase $*$, $\gamma_*$
is the specific gravity of phase \( *, D_{j}^{\text{eff}} \) is the effective diffusivity of component \( j \) in phase \( * \) (taken to be \( 1 \times 10^{-6} \) m\(^2\)/s in all directions). Fluid flow under a pressure gradient is expressed in Equation 4.1 by Darcy’s law. In this work, capillary pressure effects are taken to be small and thus the water phase pressure is equal to the gas phase pressure.

For each grid block, the energy conservation equation is given by:

\[
\frac{\partial}{\partial t} \left( V_v \rho U + V_s \rho_s C_s T \right) + \nabla \cdot (\rho u H) - \nabla \cdot (k_T \nabla T) = q_c - q_L \tag{4.2}
\]

where \( V_v \) is void volume, \( \rho \) is mass density of water, \( U \) is specific internal energy of water, \( V_s \) is rock volume, \( \rho_s \) is rock density, \( C_s \) is rock’s specific heat capacity, \( T \) is temperature, \( H \) is the enthalpy of the water, \( k_T \) is effective thermal conductivity, \( q_c \) is heat sources and \( q_L \) is heat losses to overburden and underburden. The mass and heat conservation equations are applied in each grid block and due to the connections between neighboring grid blocks, a system of coupled discretized non-linear equations are derived. These discretized equations are solved at each time step by using Newton’s method and an implicit time integrator (CMG, 2022). To constrain mass balance errors to less than 0.001\%, the convergence criterion for both nonlinear and linear solvers is set to \( 1 \times 10^{-6} \).

**4.2.3. Boundary and Initial Conditions**
For the side boundaries, an aquifer model (CMG, 2022; Vinsome et al., 1980) is applied for fluid flow into and out of the model with a constant far-field pressure equal to the original hydrostatic pressure at the elevation of the grid block. At these boundaries, heat transfer symmetry boundary conditions are imposed. For the bottom boundary, no water flow condition is imposed, and the temperature is set equal to 106.53°C, consistent with the geothermal gradient. At the top boundary, no fluid flow is imposed and a heat loss model (CMG, 2022; Vinsome et al., 1980) is used for heat loss to the atmosphere (atmosphere temperature is taken to be 16.85°C). For initial conditions, the domain has a pressure distribution consistent with the hydrostatic pressure gradient. In the target zone, the pressure is equal to about 30 MPa. For temperature, the system has a linear temperature profile from the top boundary to the bottom according to the boundary conditions (set by the geothermal gradient).

4.2.4. CO₂ Equilibrium

CO₂ component is set molar mass at 0.04401kg/mol, critical pressure at 7.376 MPa and critical temperature at 31.05°C. Due to the reservoir condition (30 MPa and 102.6°C on average), the CO₂ will exist as a supercritical fluid in the BCSU. When CO₂ is injected into the unit, it exists as a supercritical gas phase within the reservoir – it is possible that the CO₂ will dissolve into the aqueous phase and that some water vapour will enter the gas phase. The STARS™ simulator determines equilibrium between the components in the respective phases by using a K-value based equilibrium model. For the solubility of CO₂, Guo et al. (2014) found that CO₂ at conditions in the BCSU has a solubility to water equal to 1.283 ~ 1.373 mol/kg.
4.2.5. Well Configuration and Wellbore Flow/Heat Transfer Model

In this study, geothermal energy production is a by-product of CO₂ sequestration where the CO₂ replaces the hot water in the pore volume displacing it to the production well. The operational system consists of two horizontal wells with one injecting CO₂ and the other producing hot water. The injection well is placed at the top of target zone whereas the production well is placed at the bottom of target zone as displayed in Figures 4.2 and 4.3: the horizontal distance between the two wells is 6,000 m with 41.91 m vertical separation. The operation is continued until CO₂ breaks through to the production well.

The flow rate and pressure profile within the wells is modelled by using the semi-analytical model available in STARS™ based on Oballa et al. (1997) (CMG, 2022; Fontanilla et al., 1982). Table 4.2 lists the properties of the materials and dimensions in the wellbores. In the semi-analytical model, the pressure drops in the well depends on viscous drag, inertia, and gravity. Under turbulent flow, the frictional pressure gradient is determined by:

\[
\frac{\partial P}{\partial x} = \frac{2f \bar{u}^2}{D \rho}
\]  

(4.3)

where the friction factor \( f \) is determined from Colebrook’s equation (Colebrook et al., 1939), \( D \) is diameter of the tubing string, \( \bar{u} \) is the average fluid speed, and \( \rho \) is fluid density. The roughness of the internal wall of the well pipe is set equal to 0.0001.
Heat transfer between each grid block containing the well and the well itself is modelled by using a one-dimensional series radial heat transfer model with heat transfer resistances arising from the cement, casing, annulus space, insulation layer, and tubing string wall, as described by Shi et al. (2023). The heat transfer coefficient at the tubing string wall is determined by the method described by Fontanilla and Aziz (1982).

<table>
<thead>
<tr>
<th>Object</th>
<th>Dimensions</th>
<th>Material</th>
<th>Thermal Conductivity, W/m°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing</td>
<td>Inner diameter 0.163 m&lt;br&gt;Outer diameter 0.168 m&lt;br&gt;Roughness 0.0001</td>
<td>Carbon steel</td>
<td>44.96</td>
</tr>
<tr>
<td>Insulation</td>
<td>Outer diameter 0.173 m</td>
<td>Calcium Silicate</td>
<td>0.03</td>
</tr>
<tr>
<td>Casing</td>
<td>Outer diameter 0.23 m</td>
<td>Carbon steel</td>
<td>44.96</td>
</tr>
<tr>
<td>Annulus</td>
<td>Outer diameter 0.245 m</td>
<td>Water</td>
<td>0.66</td>
</tr>
<tr>
<td>Cement</td>
<td>Outer diameter 0.3 m</td>
<td>Cement</td>
<td>0.35</td>
</tr>
</tbody>
</table>

### 4.2.6. Operating Conditions

CO₂ sequestration is being done by Shell in their Quest carbon capture and storage (CCS) facility, near Edmonton, Alberta into the Basal Cambrian Sandstone unit (Shell, 2011). Here, CO₂ injection occurs at a maximum bottom-hole pressure of 32 MPa at an injection rate of 2.5 million m³/day. This is equal to 1.7 million tonnes CO₂ injected per year which is about 40% greater than that of Shell’s Quest operation. For the production well, the constraints are set to maximum 400 m³/day and minimum bottom-hole pressure 200 kPa.
4.3. Results and Discussion

The CO₂ must be compressed to enable injection into the reservoir. Shell (2021) reports that to compress 1.2 million m³/day of CO₂ to the surface target pressure of about 10 MPa, 13.7 MW of power is required. A calculation of power required for adiabatic compression for this amount of CO₂ to this target pressure requires 13.3 MW. For the target injection rate studied in this work, 2.5 million m³/day injection rate, the power required for compression of the CO₂ is 27.6 MW. This power needed for CO₂ compression translates to a GHG emission which in this case is equal to about 245 tCO₂/day (based on the emission factor of 0.37 tCO₂/MWh reported by Shell (2021)).

Figure 4.4 displays the CO₂ injection and water and gas production flow rates versus time. The CO₂ injection rate is constant throughout the operation at 2.5 million m³/day. The water production rate remains at the well constraint of 400 m³/day. The CO₂ production profile reveals that breakthrough of CO₂ at the production well occurs after about 1,470 days. The cumulative amount of water that is produced from the geothermal reservoir is equal to about 589,000 tonnes at CO₂ breakthrough. Figure 4.5 shows the cumulative CO₂ injected into the reservoir as well as the net amount of CO₂ stored after the emissions arising from the compression of CO₂ for its injection into the reservoir is taken into account. At the point of time that breakthrough occurs, the net cumulative amount of CO₂ stored is equal to 6.3 million tonnes.
Figure 4.4: CO₂ injection and production rates and water production rate. Breakthrough of CO₂ occurs at 1,470 days (exhibited by the produced gas profile).

Figure 4.5: CO₂ cumulative injection into reservoir. The net CO₂ stored is the net amount injected after taking the CO₂ generated from the compression operation into account.
Figure 4.6 displays the injection and production well bottom-hole pressures. The initial reservoir pressure is equal to 22,600 kPa. The results show that the injection pressure rises as the process evolves. The production well bottom-hole pressure remains largely constant at about 6,300 kPa. As the CO$_2$ reaches the production well, the bottom-hole pressure rises and has a peak when CO$_2$ breakthrough occurs.

Figure 4.6: Injection and production well bottom-hole pressure (BHP).

Figure 4.7 displays the temperature of the produced water versus time. The water in the geothermal reservoir is at 99.8°C but due to heat losses along the production well, the temperature realized at surface is lower at about 88.5°C. Since all of the water that is produced is
the initial water in the geothermal reservoir displaced to the production well, the produced
temperature climbs slightly through time. The reason for the small rise of the produced water
temperature is because the produced water, as it rises up the production well, heats the rock
surrounding the production well and thus heat losses from the production well decline with time.
After CO$_2$ breakthrough occurs, the temperature of the produced water rises. As Chong et al.
(2021) and Shi et al. (2023) concluded, lower heat losses of the working fluid occurs with faster
production flow rate. Thus, if operated at higher production rate, the system could produce more
hot water but on the other hand, the CO$_2$ breakthrough time would be smaller.

![Figure 4.7](image_url)

**Figure 4.7:** Temperature of surface produced water.
Figure 4.8 shows energy production rate, arising from the produced hot water, from the CO₂ sequestration operation (reference temperature of the water is 15.5°C). The system produces on average about 1.41 MW. After CO₂ breakthrough, since the water rate still remains at 400 m³/day, given the additional energy recovered in the produced CO₂, there is a slight increment of the produced energy rate at that time. Figure 4.9 displays the cumulative energy produced – the total produced prior to CO₂ breakthrough is about 49,835 MWh. On average this translates to 12,358 MWh/year. The annual average household energy use in Alberta, Canada is about 37,756 kWh/year (30,556 kWh/year for heat from natural gas and 7,200 kWh/year for electricity). Zarrouk and Moon (2014), from a review of 94 geothermal operations, found that the worldwide efficiency for converting geothermal heat to power was about 12%. Given the results of this work, this means that the combined geothermal-CO₂ sequestration system is generating the electrical energy required for about 205 households in Alberta, Canada.
Figure 4.8: Energy production rate versus time.

Figure 4.9: Cumulative energy produced versus time.
Figure 4.10 displays the evolution of the CO$_2$ plume within the BCSU versus time in the midpoint vertical plane of the horizontal wells with the vertical dimension exaggerated by a factor of 25. The results show that during CO$_2$ injection, the CO$_2$ plume evolves laterally and from the top down overriding the water in the BCSU. As injection continues, the plume spreads across the system and evolves towards the production well. After it reaches the production well after about 4 years, it comes down to the perforation at the bottom of the production well.

![CO$_2$ plume evolution](image)

**Figure 4.10:** CO$_2$ (gas) saturation within the BCSU versus time (times refer to the time interval after injection starts). Zero gas saturation (blue) means the pore space is filled with water.
4.3.1 Geothermal wastewater re-injection

The results show that about 589,000 tonnes of water are produced from the reservoir but this is an environmental issue since this water has to be disposed of. To deal with this water, a case was run where the water was co-injected at 400 m$^3$/day into the reservoir together with the CO$_2$. Even with water co-injection, CO$_2$ injectivity remains constant at 2.5 million m$^3$/day. However, to accommodate the co-injection of the two fluid phases, the injection pressure is slightly higher than that of the CO$_2$-only case, as shown in Figure 4.11. In this case, CO$_2$ breakthrough occurs slightly ahead of the CO$_2$-only case at 1,450 days.

![Comparison of injection pressure between CO$_2$-only case and CO$_2$+Water case.](image)

Figure 4.11: Comparison of injection pressure between CO$_2$-only case and CO$_2$+Water case.
The temperature profile for the co-injection case is nearly identical to that of the CO$_2$-only case except the temperature peak due to the CO$_2$ breakthrough occurs about 20 days prior to that in the CO$_2$-only case. Similarly the energy recovered is the same in the co-injection case as that in the CO$_2$-only case given that the produced temperature and water rate are nearly identical. These results reveal that even in the case where the produced water is disposed in the injection process, CO$_2$ injection and geothermal heat production is technically viable.

Figure 4.12 displays the evolution of the CO$_2$ (gas) saturation when water is co-injected with the CO$_2$ (water is injected at the same rate as is produced from the geothermal reservoir). The results show that there is an accumulation of water at the base of the system as injection occurs. This is due to gravity drainage of the injected water through the CO$_2$ (gas) rich zone which results in a richer water zone at the base of the BCSU as exhibited as the lower gas saturation there compared to that in Figure 4.10 for the CO$_2$-only injection case. The filling of part of the pore space with the injected water accelerates CO$_2$ movement across the system leading to a slightly shorter breakthrough time than that of the CO$_2$-only injection case.

In the case where the goal is CO$_2$ sequestration, the results show that energy production is possible by recovering water driven to the surface by the pressure enhancement in the reservoir due to the injected CO$_2$. The power recovered, as shown in Figure 4.8, is equal to about 1.41 MW, whereas the power needed for compression of the CO$_2$ is equal to 27.6 MW. Thus, the energy recovered is insufficient to fulfill the requirements for CO$_2$ compression but if the energy recovered is incremental to a process that was targeting CO$_2$ sequestration, then there might be benefits for recovering this additional energy.
Figure 4.12: CO$_2$ (gas) saturation within the BCSU versus time (times refer to the time interval after injection starts) for the case where produced water is co-injected with the CO$_2$. Zero gas saturation (blue) means the pore space is filled with water.

4.4. Conclusions

In this study, we examined the potential for CO$_2$-sequestration combined with geothermal heat extraction in the Basal Cambrian Sandstone unit by using a dual-horizontal well system consisting of injection and production wells spaced 6,000 m apart. The length of the horizontal wells is 800 m. The intent is to design a system where no CO$_2$ is produced back to surface. The system is operated until CO$_2$ breakthrough occurs at the production well which for the interwell spacing used here occurs after about 4 years. The results show that the system can produce energy but the power recovered is not sufficient to operate the CO$_2$ compression system. After about 4 years when CO$_2$ breakthrough occurs, the total amount of geothermal heat recovered is
49,835 MWh and the net amount of CO$_2$ stored in the geothermal reservoir is 6.3 Mt (taking the CO$_2$ generated from the compression operation into account). If the produced water is co-injected with the CO$_2$, its effect on the system is small and the energy recovered is essentially the same as the CO$_2$-only case. The results suggest that combined CO$_2$ sequestration and geothermal heat recovery systems should be examined where CO$_2$ sequestration operations are planned in mobile water geothermal reservoirs.
CHAPTER 5: Investigation of CO₂-EGR in an Offshore Natural Gas Field in Yinggehai Basin, South China Sea

5.1. Introduction

Over the past few decades, the dramatic enlargement of global greenhouse gas (GHG) concentrations in the atmosphere has raised the alarms for many nations, and thus, commitments have made towards lowering their GHG emissions (Global Methane Initiative, 2014; Paris Agreement, 2015; Global Methane Pledge, 2022; UN Net Zero Coalition 2022). To achieve the goals of these agreements, many industries have instituted policies to guide and change existing GHG intensive energy production methods to the answer the call to reduce GHG emissions. For example, Canada has committed to a 2030 emissions reduction plan and a goal of net-zero emissions by 2050 (Government of Canada, 2022; Government of Canada, 2023). There is a growing consensus that one viable method for dealing with GHG emissions is by using carbon capture and storage (CCS) or carbon capture, utilization, and storage (CCUS) (Riahi et al., 2004; Eiken et al., 2011; Bui et al., 2018) which from field operations have demonstrated that a significant GHG emission reduction can be achieved. Globally, there are many CCS operations that are planned but the total amount of planned CCS is still small relative to global GHG emissions (Global Status of CCS, 2022). Another option has been the utilization of the carbon dioxide (CO₂) for enhanced petroleum recovery such as enhanced oil recovery (EOR) and enhanced gas recovery (EGR) (Rafiee et al., 2019). Another option is the use of CO₂ in enhanced
geothermal systems (EGS) where some fraction of the injected CO$_2$ is stored in the geothermal resource (Li et al., 2015; Brown et al., 2000; Shi et al., 2023).

Enhanced gas recovery (EGR) is a concept where the injection of CO$_2$ is used to enhance the pressure and drive of natural gas from the reservoir to achieve greater natural gas recovery factor (Hamza et al., 2021). EGR has been studied for more than thirty-five years but typically with a focus on enhancing natural gas recovery and economic returns of the process (Al-Hashami et al., 2005). When applied on a conventional gas reservoir, injected CO$_2$ acts as a gas drive by pressurizing the reservoir in the region surrounding the injection well which consequently drives more natural gas to the production wells from the reservoir (Hamza et al., 2021). For unconventional gas reservoirs (such as shale gas, tight rock, coal bed methane), the injected CO$_2$ can also be used to enhance the formation permeability via hydraulic (Gao and Li, 2016; Zhou et al., 2022). For meeting CCS objectives, if less than 100% of the injected CO$_2$ is produced during the EGR process, what is lost to the reservoir can be considered as stored within the reservoir. In this manner, recovery process designs could be adapted and optimized so that a majority of the injected CO$_2$ remains in the reservoir. This may have to be done on a case-by-case basis due to the variability of the geological settings. One key benefit of natural gas systems is that the original gas in place (OGIP) provides an estimate of the potential upper bound on the gas storage capacity and caprock integrity providing lower risk for CO$_2$ leakage from the reservoir (Oldenburg and Benson, 2001). According to Liu et al.’s (2022) review, the globe scale of CO$_2$ storage capacity in conventional natural gas reservoirs is between 160 to 390 Gt and according to CO$_2$-EGR simulation studies, natural gas recovery factor can be improved by 5 to 15% (Jikich et al., 2003; Al-Hashami et al., 2005).
In conventional dry gas reservoirs, methane is the dominant component in the natural gas with small or trace amounts of other hydrocarbons and inorganic gases such as C$_2$H$_6$, CO$_2$, N$_2$, H$_2$S, etc. (Liu et al., 2022). At elevated temperature and pressures as found in natural gas reservoirs, injected CO$_2$ will exist in supercritical state (SCCO$_2$) with different physical properties compared to that of the natural gas (Pan et al., 2017). SCCO$_2$ has both gas and liquid characteristics where the density and viscosity of SCCO$_2$ is significantly larger than the methane, as shown in Figure 5.1 (Oldenburg et al., 2001). Thus, under many conditions, gravity segregation will occur between the SCCO$_2$ and methane leading to having the SCCO$_2$ placed at the bottom of the reservoir which can be used for displacement of natural gas in an up dip approach to enhance its recovery factor. Furthermore, the larger viscosity of SCCO$_2$ yields a low SCCO$_2$: natural gas mobility ratio which enhances the stability of the displacement front (reduced tendency for fingers and mixing of SCCO$_2$ with the natural gas) (Oldenburg and Benson, 2002; Al-Hashami et al., 2005).

Figure 5.1: Density and viscosity of CO$_2$ and CH$_4$ at temperature of 40, 60, and 80°C under different pressure (source from Oldenburg et al., 2001)
Thus, the characteristics of SCCO$_2$ and methane suggest that there are opportunities for conducting CCUS plus EGR project but with the goal of maximizing CO$_2$ storage or at least enough to make the extraction process carbon neutral or possibly carbon negative. A highly desired operation would be to sequester an amount of CO$_2$ such that even on consumption of the natural gas, its entire life cycle is carbon negative. From the methane combustion reaction, each mole of methane combusted yields a mole of CO$_2$. Thus, after the per mole methane GHG emissions intensity across its supply chain is known, the number of moles of CO$_2$ that have to be sequestered to yield neutral or negative GHG emission natural gas (including combustion) can be determined.

CO$_2$-EOR has been done in several commercial scale projects (MIT, 2016). This is not the case for CO$_2$-EGR where commercial scale projects are few or are in the planning stages. In 2022, BP and the Tangguh LNG joint venture partnered to work on Indonesia’s first EGR along with CCUS development (BP Indonesia, 2022). In reservoir simulation studies, methane recovery could be improved by 8 to 11\% by using CO$_2$ injection and was found to be an option at the end of the reservoir (Al-Hashami et al., 2005; Hussen et al., 2012; Khan et al., 2013). They also found that dissolution of CO$_2$ in formation water helps to delay CO$_2$ breakthrough (Al-Hashami et al., 2005; Hussen et al., 2012). In a simulation study on EGR with continuously injecting CO$_2$ into the reservoir, Schepers et al. (2009) reported that significant enhancement of recovery and about half of the total volume of CO$_2$ injected remained in the reservoir. For shale gas, Liu et al. (2013) showed that CO$_2$ has a limited effect on incremental CH$_4$ recovery (about 1\% increment) but for sequestration is effective with over 95\% of the injected CO$_2$ being trapped. Melzer (2012)
found that CO\textsubscript{2} retention in an EOR field project (after captured and recycling of all produced CO\textsubscript{2}) that over 90\% of the CO\textsubscript{2} remains stored within the reservoir.

Unlike EOR projects, one possible reason for why there are so few CO\textsubscript{2}-EGR commercial operations is due to the gap between crude oil and natural gas prices. However, with recent regulations and policies in many nations now motivating and accelerating carbon dioxide reduction, conversion, and sequestration activity (Jiang et al., 2020; Chen et al., 2022) together with carbon tax (Government of Canada, 2021), nowadays, it is expected that CO\textsubscript{2}-EGR opportunities will draw more attention for commercial development.

Here, a CO\textsubscript{2}-EGR opportunity in a large offshore natural gas field in the Yinggehai Basin in the South China Sea is explored. This field has been produced for natural gas for ~20 years and given its decline, there is a need to enhance gas production (Zhenfeng et al., 2008). This could be done by drilling new wells but another compelling option is to use CO\textsubscript{2}-EGR to not only enhance natural gas production but also sequester CO\textsubscript{2}. In this research, we explore the latter option.

5.2. Model Description

5.2.1. Geological model

The three-dimensional geological model was derived from well data of an offshore natural gas field in the Yinggehai Basin in the South China Sea. The gas reservoir exhibits a pronounced anticline structure together with complex faulting that transect the domain. The original geological model has dimensions 7,150 m by 11,000 m horizontally and 50 m vertically but for
the work reported here, a slightly smaller reservoir model is extracted from the domain as shown in Figure 5.2. A view of the formation depth is displayed in Figure 5.3. The target zone has 15 faults with the largest and there exists an extensive fault that divides the entire field into west and east parts. The minimum depth of the anticline on the west side is equal to 1220 m where on the east side it is equal to 1200 m. In the reservoir model, the OGIP is equal to 6.3×10⁹ m³ which is approximately half of the current reserves of the entire reservoir according to the operator. The domain is subdivided into three layers: the overburden and underburden mudstone layers sandwiching the natural gas bearing reservoir which consists of a fine quartz siltstone formation. The average properties of these three units are listed in Table 5.1. All of the properties of the units, existing production wellbore locations, concentration of gas components, and production rate profiles were obtained from the offshore operator. The water-gas relative permeability curves for the gas reservoir is displayed in Figure 5.4.
Figure 5.2: Three-dimensional (3D) model with faults (black lines) (vertical scale has been exaggerated by a factor of 5).
Figure 5.3: Formation depth (in m) distribution with faults (black lines).

Table 5.1: Properties of geological layers in the CO2-EGR model (from operator).

<table>
<thead>
<tr>
<th>Unit</th>
<th>Overburden (mudstone)</th>
<th>Target Formation</th>
<th>Underburden (mudstone)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anticline Depth of Top of Unit (m)</td>
<td>1,195-1,365</td>
<td>1,200-1,360</td>
<td>1,250-1,410</td>
</tr>
<tr>
<td>Average Thickness (m)</td>
<td>5</td>
<td>50</td>
<td>5</td>
</tr>
<tr>
<td>Average Horizontal Permeability (mD)</td>
<td>&lt;0.0001</td>
<td>81.4</td>
<td>&lt;0.0001</td>
</tr>
<tr>
<td>Average Vertical Permeability (mD)</td>
<td>&lt;0.0001</td>
<td>40.7</td>
<td>&lt;0.0001</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>&lt;0.01</td>
<td>0.238</td>
<td>&lt;0.01</td>
</tr>
<tr>
<td>Average Compressibility (1/kPa)</td>
<td>-</td>
<td>5.146×10^{-7}</td>
<td>-</td>
</tr>
<tr>
<td>Current (2023) Reserves (m³)</td>
<td>~1.3×10^{10}</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.4: Water-gas relative permeability curves in the gas reservoir (from operator).

Table 5.2: Concentration of gas components in the natural gas field in the Yinggehai Basin in the South China Sea (from operator).

<table>
<thead>
<tr>
<th>Components</th>
<th>CO₂</th>
<th>N₂</th>
<th>CH₄</th>
<th>Other (C₂H₆, C₃H₈, etc.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Concentration</td>
<td>1%</td>
<td>~29%</td>
<td>70%</td>
<td>&lt;1%</td>
</tr>
</tbody>
</table>

The initial average temperature of the target formation is equal to 83°C. In this reservoir, the average horizontal and vertical permeabilities are 81.4 and 40.7 mD, respectively, with 23.8% average porosity. It is well established that no geological layer has uniform properties – to add a degree of heterogeneity to the target formation, a 15% uniformly distributed random distribution of porosity and permeability are applied around the average values; the porosity distribution for the topmost layer of the reservoir is displayed in Figure 5.5.
The domain is discretized into grid blocks (illustrated in Figure 5.5); more specifically, the domain is divided into 286 twenty-five m and 550 twenty m grid blocks in the horizontal directions and a 12 grid blocks with variable dimensions in the vertical direction. The total number of grid blocks in the model is 1,887,600 (including null blocks). Mud diapirs are found within the gas reservoir (Zhenfeng et al., 2008) which are shown as internal white regions shown in Figures 5.3 and 5.5 within the formation. The mud diapirs have the same properties as that of the mudstone layers.

Figure 5.5: Porosity distribution in the topmost layer of the natural gas reservoir with faults (black lines).
5.2.2. Grid and Conservation Equations

The mass balance for each component $j$ in the water-gas system is given by (CMG 2022, Pruess, 1985):

$$\frac{\partial}{\partial t} \left[ \phi \left( \frac{x_{wj} \rho_w S_w}{MW_w} + \frac{x_{gj} \rho_g S_g}{MW_g} \right) \right] + \frac{m_j - m_{jr}}{MW_j} = \nabla \cdot \left[ \frac{k_w \rho_w}{\mu_w} c_{wj} (\nabla P_w - \gamma_w \nabla z) + D_{wj}^{eff} \nabla \left( \frac{\rho_w x_{wj}}{MW_w} \right) \right] + \frac{k_g \rho_g}{\mu_g} c_{gj} (\nabla P_g - \gamma_g \nabla z) + D_{gj}^{eff} \nabla \left( \frac{\rho_g y_j}{MW_g} \right)$$

(5.1)

where $\phi$ is porosity, $x_{wj}$ is mole fraction of component $j$ in water phase, $y_j$ is the mole fraction of component $j$ in the vapour phase, $\rho_*$ is density of phase $*$, $S_*$ is the saturation of phase $*$, $MW_*$ is the molecular weight of phase $*$, $k_*$ is the effective permeability of phase $*$, $\mu_*$ is the viscosity of phase $*$, $c_{*j}$ is the compressibility of component $j$ in phase $*$, $P_*$ is the pressure of phase $*$, $\gamma_*$ is the specific gravity of phase $*$, $D_{*j}^{eff}$ is the effective diffusivities of component $j$ in phase $*$ (taken to be equal to $1 \times 10^{-6}$ m$^2$/s in all directions). Fluid flow under a pressure gradient is expressed in Equation 5.1 by Darcy’s law. In this work, capillary pressure effects are taken to be small and thus the water phase pressure is equal to the gas phase pressure. In this model, no significant heat transfer is anticipated in the operation and thus, the system is set as isothermal at the initial temperature.

To solve Equation 5.1, the CMG STARS$^\text{TM}$ reservoir simulator is used. This numerical simulator solves the material balance for each grid block together with phase equilibrium by using the
finite volume method (CMG, 2022). These equations, for each grid block, lead to a set of simultaneous non-linear ordinary differential equations which are linearized and solved by using Newton’s method together with a Euler-based time stepping algorithm (CMG, 2022). The grid was halved in each direction to validate that the grid was sufficiently refined. When this was done, the results changed by less than 0.1%.

5.2.3. Boundary and Initial Conditions

For the side reservoir boundaries, a Carter-Tracy aquifer model (Carter and Tracy, 1960; CMG, 2022) is applied for fluid flow into and out of the model with a constant field pressure equal to the original hydrostatic pressure at the elevation of the grid block. This provides a realistic representation of the boundary of the domain where it is connected to the formation beyond the edges of the model. The top and bottom boundaries (of the mudstone layers) are sealed with no flow allowed as well as the mud diapir regions. For initial conditions, the domain has a pressure distribution consistent with the hydrostatic pressure gradient. In the target zone, after decades of natural gas recovery, from operator data, the current (2023) pressure has declined to an average value of 6,050 kPa at the top of the formation. Since an anticline structure is present in this system, a gas cap exists for this model where the water-gas contact line is at 1,375m depth as illustrated in Figure 5.6. In the overburden and underburden mudstone layers, the water saturation (in the small pore volume there) are set equal to unity. In the gas zone, the initial water saturation provided by the operator is equal to 0.12 which is lower than the irreducible water saturation of 0.485 and thus, this water is not mobile. Water production, however, can originate from the water zone below the water-gas contact.
5.2.4. CO₂ Condition

Given the critical point of CO₂ (critical pressure 7.376 MPa, critical temperature 31.05°C) versus the initial conditions of the reservoir (6,050 kPa and 83°C), injected CO₂ will exist initially as gas phase. However, after continuous CO₂ injection, the formation pressure increases and pass the critical point. In that case, for parts of the reservoir with rich CO₂ saturation, it will exist as a supercritical fluid. Therefore, a gas-liquid K-value at 83°C is set as listed in Table 5.3 as well as its supercritical phase properties and viscosity (shown in Figure 5.1) to enable CO₂ dissolution in the water (Reid et al., 1997; Oldenburg et al., 2001; CMG, 2022). Over the pressure range (at 83°C) that is examined here, the CO₂ density depends roughly linearly on pressure (compressibility listed in Table 5.3). The gas-liquid K-value correlation (Reid et al., 1997) is given as follows:
\[ k = \left( \frac{K_{V1}}{P} + K_{V2}P + K_{V3} \right) e^{K_{V4}T - K_{V5}} \]  

(5.2)

where \( P \) is pressure and \( T \) is temperature and \( K_{V1}, K_{V2}, K_{V3}, K_{V4}, K_{V5} \) are correlation coefficients listed in Table 5.3.

**Table 5.3: Parameter for CO\textsubscript{2} condition in this model (data from Reid et al., 1997; Oldenburg et al., 2001; CMG, 2022).**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mass Density (kg/m\textsuperscript{3})</td>
<td>127.52</td>
</tr>
<tr>
<td>Viscosity (cp)</td>
<td>0.019</td>
</tr>
<tr>
<td>Compressibility (1/kPa)</td>
<td>1.25×10\textsuperscript{-5}</td>
</tr>
<tr>
<td>K-value correlation coefficients</td>
<td>( K_{V1} = 8.6212\times10^8 ) kPa, ( K_{V2} = 0 ) 1/kPa, ( K_{V3} = 0 ), ( K_{V4} = -3103.39^\circ \text{C} ), ( K_{V5} = -272.99^\circ \text{C} )</td>
</tr>
</tbody>
</table>

**5.2.5. Formation Rock and Aquifer Salinity Composition**

According to the data provided by the operator, the initial mineral and water composition that exist in the natural gas reservoir rock are listed in Tables 5.4 and 5.5.

**Table 5.4: Composition of formation rock in natural gas reservoir (from operator).**

<table>
<thead>
<tr>
<th>Minerals in Formation Rock</th>
<th>Average Volume%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>57.73</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>1.69</td>
</tr>
<tr>
<td>Ankerite</td>
<td>1.13</td>
</tr>
<tr>
<td>Siderite</td>
<td>5.88</td>
</tr>
<tr>
<td>Argillaceous</td>
<td>9.77</td>
</tr>
<tr>
<td>Other</td>
<td>23.8</td>
</tr>
</tbody>
</table>
Table 5.5: Initial composition of aquifer water in natural gas reservoir (from operator).

<table>
<thead>
<tr>
<th>Ions in the Aquifer</th>
<th>Concentration (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>K⁺ and Na⁺</td>
<td>12,200</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>224</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>95</td>
</tr>
<tr>
<td>Cl⁻</td>
<td>17,699</td>
</tr>
<tr>
<td>HCO₃⁻</td>
<td>2289</td>
</tr>
<tr>
<td>Salinity</td>
<td>32,744</td>
</tr>
<tr>
<td>pH</td>
<td>7.8</td>
</tr>
</tbody>
</table>

5.2.6. Faults

There are 15 faults that are within the volume of the model. A fault is a planar discontinuity in a rock volume arising from displacement of one part of the rock relative to another part of the rock. In a natural gas reservoir, there is potential that the fault could lead to gas transmission from one rock layer to another rock layer. However, this depends on the amount of cementation that occurs within the fault. For the faults in the natural gas reservoir studied here, it is not that clear how transmissible the faults are. According to operator data, all of the production wells located on the west and east side of the faults demonstrated similar pressure decline throughout the past 20 years of gas production which suggests that the faults are open to transmission of fluid between each side of the fault. For the model, the faults are assigned transmissibility multipliers (CMG, 2022). Following Manzocchi et al. (1999), we use a multiplier value of 0.3 – a history match of the natural gas operation (not presented here) demonstrated that this value provides a reasonable match of the gas flow rates and pressure evolution of the system.
5.2.7. CO₂-EGR Well Locations

After decades of production, the reservoir pressure in the target natural gas declines: according to the operator, the initial pressure was about 15,000 kPa and the initial rate was $2.7 \times 10^5$ Sm$^3$/day (depends on production well). Twenty years later, the current pressure is 6,050 kPa and the production rate has declined to $0.3-1.8 \times 10^5$ Sm$^3$/day (depends on production well). For evaluation of CO₂-EGR, the initial condition of the natural gas reservoir is the current condition. The operator has decided to drill new wells for the injection of CO₂ but is unsure on the best locations for those wells. For production of natural gas, existing horizontal production wells will be used in this model. Three different cases will be evaluated for testing CO₂-EGR performance.

In the first case (Case 1a and 1b), an existing horizontal well (800 m long) on the west side of the largest fault will be used for production with two new CO₂ injection wells 1000 m (Case 1a) and 2000 m (Case 1b) placed directly north and south of the horizontal well, as displayed in Figure 5.7.
In the second case (Cases 2a and 2b), as shown in Figure 5.8, production of natural gas is through an existing short horizontal well (100 m long) located between faults whereas the two CO₂ injectors are positioned at separations 750 m (Case 2a) and 1500 m (Case 2b) away from the horizontal well in the east-west direction.
Figure 5.8: Well locations (red dots are injection well locations and green line is horizontal production well) for 750 m well separation (Case 2a, shown left) and 1500 m well separation (Case 2b, shown right).

The last case (Case 3) is displayed in Figure 5.9 where three injection wells are placed around the horizontal production well used in Cases 1a and 1b. The separation between each injector and the horizontal production well is equal to 1500 m.
Figure 5.9: Well location (red dots are injection well locations and green line is horizontal production well) for Case 3. The separations between the injectors and the horizontal well are equal to 1,500 m.

In all cases, the first year is a continuation of production with maximum rate set at 1.8x10^5 Sm^3/day and minimum bottom hole pressure of 1,000 kPa. After the one-year production period, CO_2 injection starts at 2,500,000 m^3/day into each injection well and the horizontal production well is operated with a minimum bottom hole pressure of 1,000 kPa. For the cases examined here, nine years of CO_2-EGR is modelled.
5.3. Results and Discussion

5.3.1. Cases 1a and 1b

Figure 5.10 displays the CO₂ injection and production rates, methane and total gas production rates, and cumulative methane and total gas production volumes versus time for the Cases 1a and 1b. After 1 year of production, CO₂ injection starts at 2.5x10⁶ Sm³/day. The CO₂ production rate profiles reveal that breakthrough to the horizontal production well occurs after about 1.6 years of CO₂ injection in Case 1a (1,000 m well separation) and about 7.5 years of CO₂ injection for Case 1b (2,000 m well separation). The methane and total gas rate production profiles show that for Case 1a, the methane rate peaks after about 1.6 years of CO₂ injection at about 130,000 Sm³/day after which it declines – the remaining gas that is produced is N₂ as well as CO₂. The rise of the CO₂ is the dominant component in the produced gas after breakthrough. For Case 1b, over the 9 years of CO₂ injection, since breakthrough occurs after about 7.5 years of CO₂ injection, the main component in the produced gas is methane over that period of time. The cumulative produced gas volume profiles show that after 9 years of CO₂ injection, Cases 1a and 1b produce 275 and 312 million Sm³ of methane, respectively.

Figure 5.11 displays the evolution of the CO₂ mole fraction in the gas phase in the target reservoir in Case 1a. The results show that the CO₂ plume evolves radially away from the injection wells with merging near the production well. The presence of the faults does not present a significant barrier to flow. Figure 5.12 shows the evolution of the pressure distribution.
in the reservoir. After the twenty years of production throughout the reservoir, the pressure has declined to 6,050 kPa uniformly within the reservoir. Thereafter, only further production is done from the single horizontal well and after the one year of production, a low pressure region exists around the horizontal well. Thereafter, after CO₂ injection starts, regions of elevated pressure exist that are larger than that of the CO₂ plume shown in Figure 5.11. Even though the CO₂ plume does not exhibit much interference from the faults, the region of elevated pressure does appear to be delayed moving through the faults to the east side of the reservoir.
Figure 5.10: Cases 1a and 1b – CO₂ injection and production rates, methane and total gas rates, and methane and total cumulative volume produced.
Figure 5.11: Case 1a (1000 m well separation) – evolution of CO$_2$ concentration (mole fraction) (red points are injection wells and green line is horizontal production well).
Just before start of CO₂ injection  
After 1 year of CO₂ injection

After 5 years of CO₂ injection  
After 9 years of CO₂ injection

Figure 5.12: Case 1a (1000 m well separation) – evolution of pressure (kPa) (red points are injection wells and green line is horizontal production well).
Figure 5.13 shows how the CO₂ plume evolves in the target reservoir in Case 1b. Similar to Case 1a, the plume evolves radially surrounding and after nine years of CO₂ injection, the upper CO₂ plume has nearly reached the horizontal production well. Figure 5.14 displays the evolution of the pressure distribution in the reservoir which reveals that high pressure regions surround the injection wells and low pressure zone surrounding the production well which persists since break through does not occur until about 7.5 years of CO₂ injection.

Just before start of CO₂ injection

After 1 year of CO₂ injection

After 5 years of CO₂ injection

After 9 years of CO₂ injection
Figure 5.13: Case 1b (2000 m well separation) – evolution of CO₂ concentration (mole fraction) (red points are injection wells and green line is horizontal production well).

![Image of CO₂ concentration evolution over time](image)

Just before start of CO₂ injection

After 1 year of CO₂ injection

After 5 years of CO₂ injection

After 9 years of CO₂ injection
Figure 5.14: Case 1b (2000 m well separation) – evolution of pressure (kPa) (red points are injection wells and green line is horizontal production well).

5.3.2. Cases 2a and 2b

This case has the horizontal production well placed amongst the faults with the injection wells placed in the east and west directions. Figure 5.15 displays CO₂ injection and production rates and methane and total gas rates and cumulative produced volumes for Cases 2a (750 m well separation) and 2b (1,500 m well separation). Note in this case, the horizontal production well is 8 times shorter than that of Cases 1a and 1b which limits the gas production rates. The results show that CO₂ break through occurs at ~2 and ~4 years after CO₂ injection starts for Cases 2a and 2b, respectively. The methane and total gas rates demonstrate that methane rates are lower than that of Cases 1a and 1b. After break through, the produced gas consists mainly of CO₂.
Figures 5.16 and 5.17 show the evolution of the CO$_2$ mole fraction in the gas phase and pressure in the reservoir for Case 2a. The results show that initially, the CO$_2$ plume is circular in shape but then boundary effects start to affect the plume on the east side of the faulted zone. Also, as shown at 5 years of CO$_2$ injection, the faults are interfering with purely radial growth of the plume. The elevated pressured zone due to CO$_2$ injection is larger than that of the CO$_2$ plume and evolves in a circular shape with boundary effects leading to some asymmetry. At the early stage of the process, the faults do appear to interfere pressure propagation but after break through, the pressure becomes uniform within the faulted zone near the production well. The results demonstrate that the faults have a limited but real impact on the evolution of the CO$_2$ plume and pressure distribution in the reservoir. The limited extend of the CO$_2$ plume in the reservoir after 9 years of injection reveals that there remains a large amount of methane in the reservoir which could be replaced by CO$_2$ in the system.

Figures 5.18 and 5.19 display the CO$_2$ plume and pressure distribution versus time for Case 2b. The plume and pressure distributions evolve but the impact of the east boundary on the east plume is evident which promotes its more rapid movement towards the production well than that of the west plume. The images show that the faults slow the growth of the plumes.
Figure 5.15: Cases 2a and 2b – CO₂ injection and production rates, methane and total gas rates, and methane and total cumulative volume produced.
Figure 5.16: Case 2a (750 m well separation) – evolution of CO₂ concentration (mole fraction) (red points are injection wells and green line is horizontal production well).
Figure 5.17: Case 2a (750 m well separation) – evolution of pressure (kPa) (red points are injection wells and green line is horizontal production well).
Figure 5.18: Case 2b (1,500 m well separation) – evolution of CO$_2$ concentration (mole fraction) (red points are injection wells and green line is horizontal production well).
Figure 5.19: Case 2b (1,500 m well separation) – evolution of pressure (kPa) (red points are injection wells and green line is horizontal production well).
5.3.3. **Case 3**

Figure 5.20 presents profiles of the CO$_2$ injection and production rates, methane and total gas rates, and cumulative methane production volume versus time. The results show that CO$_2$ breakthrough occurs at ~5 years. After this occurs, the slope of methane production rate declines as more of the gas produced consists of CO$_2$. However, the methane production rates remains above the initial methane production rate although it appears to peak at about 8.7 years after CO$_2$ injection started.

Figures 5.21 and 5.22 display the evolution of the CO$_2$ plume and pressure in the reservoir. After CO$_2$ injection starts, circular CO$_2$ plumes evolve around the injection wells but boundary effects are evident for the top west plume which tends to promote this plume fastest towards the horizontal production well. The pressurized region surrounding the injection wells are larger than that of the CO$_2$ plume and eventually, nearly the entire reservoir is pressurized.
Figure 5.20: Case 3 – CO₂ injection and production rates, methane and total gas rates, and methane and total cumulative volume produced.
Figure 5.21: Case 3 – evolution of CO$_2$ concentration (mole fraction) (red points are injection wells and green line is horizontal production well).
Just before start of CO\(_2\) injection

After 1 year of CO\(_2\) injection

After 5 years of CO\(_2\) injection

After 9 years of CO\(_2\) injection

Figure 5.22: Case 3 – evolution of pressure (kPa) (red points are injection wells and green line is horizontal production well).
5.3.4. Summary

Two additional cases were run where no CO\(_2\) is injected into the reservoir but production continues from either the Case 1 or Case 2 horizontal production wells. A comparison of the cumulative methane (Figure 5.23) recovered reveals that in both Cases 1 and 2, CO\(_2\) injection enhances the amount of methane recovered from the reservoir. In Cases 1 and 2, the volume of CO\(_2\) injected into the reservoir is the same but due to the shorter horizontal production well, the produced methane volumes are smaller for the Cases 2a and 2b. Given the greater amount of injected CO\(_2\) in Case 3, the cumulative amount of methane produced is greater than that of Cases 1a and 1b (where the same horizontal production well is used).

![Figure 5.23: Cumulative methane produced from the reservoir for all cases.](image-url)
Table 5.6 lists a summary of the results at the end of the operations which reveal that the CO$_2$-EGR operation yields incremental methane production as high as 127% as shown by Case 3 over its base case (Case 1 base case). For Cases 1 and 2, the amount of CO$_2$ injected into the reservoir is equal (since have two injection wells in those cases) and the net stored CO$_2$ that remains in the reservoir is equal to about 30 Mt for these cases. For Case 3, given its additional injection well, its operation stored about 45 Mt of CO$_2$ in the reservoir.

**Table 5.6: Summary of results for all cases.**

<table>
<thead>
<tr>
<th>Case</th>
<th>Incremental methane from base cases or CO$_2$-EGR cases (million Sm$^3$)</th>
<th>Incremental methane volume over no CO$_2$-EGR base case, %</th>
<th>Net CO$_2$ Stored in the reservoir, Mt</th>
<th>Cumulative methane including first twenty years of production (million Sm$^3$)</th>
<th>CO$_2$ Generated for Combusting Total Produced Methane, Mt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1 base case (No CO$_2$-EGR)</td>
<td>224.6</td>
<td>–</td>
<td>–</td>
<td>16,225</td>
<td>30.15</td>
</tr>
<tr>
<td>Case 2 base case (No CO$_2$-EGR)</td>
<td>79.6</td>
<td>–</td>
<td>–</td>
<td>16,080</td>
<td>29.88</td>
</tr>
<tr>
<td>Case 1a</td>
<td>275.2</td>
<td>23</td>
<td>28.09</td>
<td>16,275</td>
<td>30.24</td>
</tr>
<tr>
<td>Case 1b</td>
<td>312.4</td>
<td>39</td>
<td>30.55</td>
<td>16,312</td>
<td>30.31</td>
</tr>
<tr>
<td>Case 2a</td>
<td>105.5</td>
<td>33</td>
<td>29.16</td>
<td>16,105</td>
<td>29.92</td>
</tr>
<tr>
<td>Case 2b</td>
<td>162.0</td>
<td>103</td>
<td>30.54</td>
<td>16,162</td>
<td>30.03</td>
</tr>
<tr>
<td>Case 3</td>
<td>508.8</td>
<td>127</td>
<td>45.32</td>
<td>16,508</td>
<td>30.68</td>
</tr>
</tbody>
</table>

Over the first twenty years, $1.6 \times 10^{10}$ Sm$^3$ of methane was produced from the reservoir – the total volume of methane produced from the cases is also listed in Table 5.6. The total amount of CO$_2$ that would be generated from the combustion of the methane (according CH$_4$ + 2 O$_2$ → CO$_2$ + 2 H$_2$O) is also listed in Table 5.6. The results demonstrate that for Cases 1a, 1b, 2a, 2b, and 3, the CO$_2$-EGR operation renders the entire consumption of the methane produced from the reservoir in these cases as carbon negative. The other cases are fall short with respect to CO$_2$ storage but
are close. Thus, the natural gas reservoir case study examined here proves that there is potential for carbon negative natural gas operations with respect to the consumption of the produced methane. Note, it does not consider the emissions associated with the compression for CO₂ transport and injection nor the operations of the offshore production facility. A full life cycle assessment would be needed to assess this; this will be left for the next stage of the research. On other consideration is that the original natural gas reservoir pressure was 15,000 kPa whereas in the cases examined here, the maximum pressure reached was about 7,000 kPa. This suggests that more CO₂ could be sequestered in the reservoir if the original reservoir pressure was achieved on CO₂ injection.

5.4. Conclusions

In this study, we examined the performance of a CO₂-EGR process conducted on an offshore natural gas field that had undergone twenty years of prior gas production in the Yinggehai Basin in the South China Sea. One key feature of the reservoir is that it has faults that run roughly down the centre of the reservoir. In total, five cases were examined to determine how injection and production well placement would affect the performance of the process. The results show that CO₂-EGR enhances the amount of methane produced from the reservoir. The amount depends on the placement of the injection and production well. The CO₂ plumes are shown to evolve in the reservoir until they encounter each other or the fault system or the production well. The incremental recovery of methane is between 23 and 127%. The results also reveal that the
CO$_2$-EGR opens the door to potentially carbon negative natural gas with respect to the consumption of the natural gas as fuel (the total life cycle has not yet been assessed).
CHAPTER 6: Investigation of a CO₂ Sequestration Pilot in an Offshore Feldspar-Quartz Sandstone Formation in the Pearl River Mouth Basin, South China Sea

6.1. Introduction

Over the past few decades, global alarms have been going off on the rise of greenhouse gas (GHG) concentrations in the atmosphere and as such, many nations, including Canada, have made commitments towards lowering their GHG emissions (Paris Agreement, 2015; Government of Canada, 2021). These emissions arise from human activities including energy, transportation, agriculture, and industry (in all its processes and products). Many industries have answered the call to reduce GHG emissions and develop methods and changes to current behaviours to achieve this goal. Carbon capture and storage (CCS) or carbon capture, utilization, and storage (CCUS) (Riahi et al., 2004; Eiken et al., 2011; Bui et al., 2018) offer a significant option to reduce GHG emissions released into the atmosphere. Followed by more recent onshore CCUS infrastructure construction, land based CCUS is in the transition of becoming a mature technology with multiple operations and growing expertise and experience (Saito et al., 2006; Alcorn et al., 2018; Xu et al., 2021; Blaizot et al., 2022). However, there are risks for carbon dioxide migration to the surface that are mitigated through long term monitoring for land-based CCS (Leung et al., 2014; Jones et al., 2015). These risks can be offset to some degree by conducting offshore CCS.

The world’s first offshore CCS operation was conducted by Equinor in the Sleipner field starting in 1996. In this operation, approximately 1 million tonnes of CO₂ is captured and stored at Sleipner each year. Another offshore CCS subsea is the Snøhvit site in the Barents Sea which
was started in 2008 (Equinor, 1996; Hansen et al., 2013; Furre et al., 2019). Snøhvit is a gas and condensate field from which liquified natural gas (LNG) is the main product (Equinor, 1996; Hansen et al., 2013; Furre et al., 2019); approximately 700,000 Mt of GHG (carbon dioxide) is stored in the formation per year. Despite this experience, there are still operational uncertainties for the storage of carbon dioxide in offshore subsea formations.

After injecting gas phase carbon dioxide into the target reservoir during sequestration, the carbon dioxide experiences structural, residual, solubility, and mineral trapping (Gislason et al., 2014). Mineral trapping with gas phase carbon dioxide occurs over a time scale of order of thousands of years and thus, there could be opportunities for leaking to formations above unless a competent caprock is present. Another method, referred to as CarbFix, injects CO$_2$-saturated water into the reservoir avoiding gas phase within the formation which implies no buoyant gas migration and a less strict requirement for a competent caprock (Gislason et al., 2014; Kelemen et al., 2020). If the water has other materials added, there is potential that mineral trapping could be accelerated. However, for storage of meaningful amounts of carbon dioxide, given that only about 5% of the injected mass would be carbon dioxide, this method requires significant volumes of water (Gislason and Oelkers, 2014).

Fortunately, for offshore carbon dioxide sequestration, the supply of water is not a critical concern since sea water can be used. At 1 atm and 20°C, the amount of fresh water and sea water needed to dissolve 1 tonne of CO$_2$ are equal to 580 and 701 tonnes, respectively (Weiss 1974; Snæbjörnsdóttir et al. 2020). The higher the pressure, the greater the amount of CO$_2$ stored whereas the larger the temperature, the lower is the CO$_2$ solubility.
Despite the dire need for CO₂ sequestration and the maturity of the Sleipner CSS and Snøhvit CCUS projects, there are few existing commercial offshore CCS/CCUS projects now operating. The K12-B project in the Netherlands and the Tomakomai CCS demonstration project in Japan started operating in 2004 and 2016, respectively, and stopped operations in 2017 and 2019, respectively. The Lula Project in Brazil and Enping Project in China were operating in 2011 and 2021, respectively, and are still both operating today (Ringrose and Meckel, 2019; Li, 2022). Among the projects above, only the Lula Project is operating under CO₂-EOR method on an ultra-deepwater field (Rosa et al., 2018). Other than Lula, the rest of the operations are all pure offshore CO₂ sequestration projects.

Due to the learnings of the Sleipner and Snøhvit projects, Ringrose and Meckel (2019) concluded that several prospective offshore regions have a cumulative storage capacity of over 100 GtCO₂ after an evaluation of the distribution and thickness of sediment accumulations over continental margins. Six planned offshore CCUS projects that are planned are the Northern Lights and Longship projects in Norway, Porthos project in the Netherlands, CarbonNet project in Australia, Acorn and Teesside projects in the UK, and Houston Ship Channel project in the US (Li, 2022).

CO₂ fixation via mineral trapping can be subdivided into two stages as illustrated in Figure 6.1. First, continuous injection of gas phase CO₂ gradually lowers the pH (the aqueous phase becomes more acidic) as follows (Xu et al., 2014):
CO₂(g) + H₂O ↔ H₂CO₃ \hspace{1cm} (6.1) 
H₂CO₃ ↔ H⁺ + HCO₃⁻ \hspace{1cm} (6.2)

**Figure 6.1: Mineral trapping steps of CO₂ sequestration.**

Second, alkaline silicate minerals in the formation rock will undergo dissolution reactions which further alter the formation environment pH. Reactions that yield more alkalinites will precipitate carbonate minerals (Salek et al., 2013). Under alkaline conditions, these reactions occur when cations arising from prior reactions of alkaline silicate minerals in the formation rock or aquifer react with CO₂. For example, in a feldspar sandstone formation, minerals such as anorthite or K-feldspar will react with CO₂ with the production of calcite and kaolinite or dawsonite (Rochelle et al., 2004; Yanzhong et al., 2020):

Anorthite (CaAl₂Si₂O₈) + CO₂(ₐq.) + H₂O
→ calcite (CaCO₃) + kaolinite (Al₂Si₂O₅(OH)₄) \hspace{1cm} (6.3)
KAlSi$_3$O$_8$ (K-feldspar) + Na$^+$ + CO$_2$ (aq.) + H$_2$O

→ NaAlCO$_3$(OH)$_2$ (dawsonite) + 3SiO$_2$ (quartz/chalcedony/cristobalite) + K$^+$  \hspace{1cm} (6.4)

The dissolved bicarbonate ion (HCO$_3^-$) reacts with divalent cations such as Ca$^{2+}$ and Mg$^{2+}$ from the aquifer resulting in mineral trapping of carbon dioxide in the form of precipitate carbonate minerals (Gunter et al., 1997; Liu et al., 2019):

Ca$^{2+}$ + HCO$_3^-$ → CaCO$_3$ + H$^+$ \hspace{1cm} (6.5)

Mg$^{2+}$ + HCO$_3^-$ → MgCO$_3$ + H$^+$  \hspace{1cm} (6.6)

5CO$_2$ + 5CaCO$_3$ + Mg$_5$Al$_2$Si$_3$O$_{10}$(OH)$_8$

→ 5CaMg(CO$_3$)$_2$ (dolomite) + Al$_2$Si$_2$O$_5$(OH)$_4$ (kaolinite)

+ SiO$_2$ (silica) + 2H$_2$O \hspace{1cm} (6.7)

The reactions listed above (amongst other CO$_2$ mineralization reactions) demonstrate that there are mechanisms for fixation of CO$_2$ in these aquifer systems but the conditions for rapid fixation are still not resolved. In the work reported here, an assessment of CO$_2$ sequestration with mineralization is examined in a detailed reservoir model of the first China offshore CO$_2$ sequestration operation in a shallow subsea feldspar-quartz sandstone aquifer system located in the Pearl River Mouth Basin in the South China Sea.
6.2. Model Description

6.2.1. Geological model

The three-dimensional aquifer model, displayed in Figure 6.2 with contour map on target formation depth, was derived from well data from an offshore oil production operation located in the Pearl River Mouth Basin in the South China Sea. The target subsea units for carbon dioxide sequestration are deeper than the oil production intervals. The model spans the overburden mudstone layer, a middle feldspar-quartz sandstone formation (FQSF) which is the target formation for carbon dioxide injection which has top depth equal to between 830 and 920 m subsea, and a lower mudstone unit below the FQSF. The average properties of these three units are listed in Table 6.1. All of the properties of the units, existing wellbore location, and concentration of carbon dioxide available, and injection rate were obtained from a large offshore operator.
Figure 6.2: Views of the target FQSF CO$_2$ sequestration target aquifer: (a) three-dimensional (3D) view (vertical scale exaggerated by a factor of 5) and (b) contour map of target formation depth (in m).

Table 6.1: Properties of units in the sequestration model (from operator).

<table>
<thead>
<tr>
<th>Unit</th>
<th>Overburden (mudstone)</th>
<th>Target Formation (FQSF)</th>
<th>Underburden (mudstone)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Depth of Top of Unit (m)</td>
<td>811.5-822.5</td>
<td>827-834</td>
<td>876-883</td>
</tr>
<tr>
<td>Average Thickness (m)</td>
<td>15.5</td>
<td>49</td>
<td>100</td>
</tr>
<tr>
<td>Average Horizontal Permeability (mD)</td>
<td>&lt;0.0001</td>
<td>1698</td>
<td>10</td>
</tr>
<tr>
<td>Average Vertical Permeability (mD)</td>
<td>&lt;0.0001</td>
<td>849</td>
<td>5</td>
</tr>
<tr>
<td>Average Porosity</td>
<td>&lt;0.01</td>
<td>0.29</td>
<td>0.05</td>
</tr>
<tr>
<td>Average Compressibility (1/kPa)</td>
<td>-</td>
<td>2.9×10^{-6}</td>
<td>-</td>
</tr>
</tbody>
</table>
The geology model consists of a domain with dimensions 4,500 m x 4,500 m horizontally and 164.5 m vertically as shown in Figure 6.2(a). The target zone has an anticline with minimum depth equal to 827 m. The initial average temperature of the target formation is equal to 52.4°C. In this formation, the average horizontal and vertical permeabilities are 1,698 and 849 mD, respectively, with 29% average porosity in the FQSF. The domain is discretized into grid blocks as illustrated in Figure 6.2(b) which shows the FQSF formation depth (red is deeper and blue is shallower). More specifically, the domain is divided into a hundred 45 m grid blocks in each of the horizontal directions and 9 grid blocks with variable dimensions ranging from 811.5 m to 883 m in the vertical direction. The total number of grid blocks in the model is 90,000 (including null blocks).

It is well established that no geological layer has uniform properties – to add a degree of heterogeneity to the target formation and in the absence of other information, a 15% uniformly distributed random distribution of porosity and permeability are applied around the average values; the porosity distribution for the topmost layer of the FQSF is displayed in Figure 6.3.
Figure 6.3: Porosity distribution in the topmost layer of the FQSF.

6.2.2 Governing Equations

The mass balance for each component $j$ in the water-gas system is given by (CMG 2022, Pruess, 1985):

$$\frac{\partial}{\partial t} \left[ \phi \left( \frac{x_{wj} \rho_w S_w}{MW_w} + \frac{x_{gj} \rho_g S_g}{MW_g} \right) \right] + \frac{m_j - m_{jr}}{MW_j} = \nabla \cdot \left[ \frac{k_w}{\mu_w} c_{wj}(\nabla P_w - \gamma_w \nabla z) + D_{wj}^{\text{eff}} \nabla \left( \frac{\rho_w x_{wj}}{MW_w} \right) \right]$$

(6.8)
\[ + \frac{k_g \rho_g}{\mu_g} c_{gj} \left( \nabla P_g - \gamma_g \nabla z \right) + D_{gj}^{\text{eff}} \nabla \left( \frac{\rho_g y_j}{M_{W_g}} \right) \]

where \( \phi \) is porosity, \( x_{wj} \) is mole fraction of component \( j \) in water phase, \( y_j \) is the mole fraction of component \( j \) in the vapour phase, \( \rho_* \) is density of phase *, \( S_* \) is the saturation of phase *, \( M_{W_*} \) is the molecular weight of phase *, \( k_* \) is the effective permeability of phase *, \( \mu_* \) is the viscosity of phase *, \( c_{*j} \) is the compressibility of component \( j \) in phase *, \( P_* \) is the pressure of phase *, \( \gamma_* \) is the specific gravity of phase *, and \( D_{*j}^{\text{eff}} \) is the effective diffusivity of component \( j \) in phase *.

Water and gas flow under a pressure gradient is expressed in Equation 6.8 by the multiphase Darcy’s law. The component material balance deals with its transport, accumulation, and reactions between and amongst the gas, aqueous, and solid (mineral) phases. The reactions occur within the aqueous phase causing either the dissolution or precipitation of mineral solid. In this work, capillary pressure effects are taken to be small and thus the water phase pressure is equal to the gas phase pressure. In this model, no significant heat transfer is anticipated in the operation and thus, the system is set as isothermal at the initial temperature. The diffusion coefficients are found from the Stokes-Einstein relationship (Miller, 1924; CMG, 2022):

\[ D_{*k}^{\text{eq}} = \frac{10^{10} k_B T}{6\pi \mu_k r_i} \]  \hspace{1cm} (6.9)

where \( k_B \) is the Boltzmann constant \( 1.3806485279 \times 10^{-16} \) (g cm\(^2\) s\(^{-2}\) k\(^{-1}\)), \( T \) is the absolute temperature (K), \( \mu_k \) is the phase viscosity (cP), and \( r_i \) is ion radius (Å).
Equations 6.8 and 6.9 are solved in the CMG GEM™ compositional reactive reservoir simulator (CMG, 2022). GEM™ is an Equation-of-State (EoS) reservoir simulator often used for reservoir systems where compositional and phase equilibrium is a key contributor to system dynamics. More details of its formulation can be found in its User Manual (CMG, 2022).

6.2.3. Boundary and Initial Conditions

At the bottom reservoir boundaries, a Carter-Tracy aquifer model (Carter and Tracy, 1960; CMG, 2022) is applied for fluid flow into and out of the model with a constant field pressure equal to the original hydrostatic pressure at the elevation of the bottom-most grid blocks. This provides a realistic representation of the boundary of the domain where it is connected to the aquifer beyond the edges of the model. The top boundary is sealed with no flow allowed. For initial conditions, the domain has a pressure distribution consistent with the hydrostatic pressure gradient with a pressure of 8.4 MPa at 827 m depth (in the target zone). In the target zone, the aquifer is completely filled with water, that is, \( S_w = 1 \).

6.2.4. Equation of State: \( \text{CO}_2 \) Solubility

Given the critical point of carbon dioxide (critical pressure 7.376 MPa, critical temperature 31.05°C) versus the initial conditions of the reservoir (~8.4 MPa and 52.4°C), on injection, the \( \text{CO}_2 \) will exist as a supercritical fluid in the FQSF. The solubility of carbon dioxide in the aquifer water depends on pressure and temperature and is expressed by a Henry’s law correlation and B-DOT model (Harvey, 1996; CMG, 2022); at each time step, it is assumed that thermodynamic
equilibrium for the carbon dioxide occurs between the gas and aquifer phases (Henry, 1803). Henry’s constants \( H_i \) are functions of pressure, temperature, and salinity (Nirmalakhandan and Speece, 1988; CMG, 2022) as follows:

\[
\ln H_i = \ln H_i^* + \frac{\bar{v}_i (P - P^*)}{RT}
\]  

(6.10)

where \( H_i \) is Henry’s constant for component \( i \) at pressure \( P \) and temperature \( T \), \( H_i^* \) is the Henry’s constant for component \( i \) at the reference pressure \( P^* \) and temperature \( T \), \( R \) is the universal gas constant, and \( \bar{v}_i \) is partial molar volume of component \( i \). To determine \( H_i^* \), Harvey et al.’s (Harvey, 1996) correlation is used:

\[
\ln H_i^{\infty} = \ln P_{H_2O}^{\infty} + A(T_{r,H_2O})^{-1} + B\left(1 - T_{r,H_2O}\right)^{0.355}(T_{r,H_2O})^{-1} + C\left[e^{(1-T_{r,H_2O})} \right](T_{r,H_2O})^{-0.41}
\]  

(6.11)

where \( H_i^{\infty} \) is Henry’s constant for component \( i \) at the saturation pressure of water, \( P_{H_2O}^{\infty} \) is saturation pressure of water, \( T_{c,H_2O} \) is critical temperature of water, and \( T_{r,H_2O} = \frac{T}{T_{c,H_2O}} \), and \( A = -9.4234, B = 4.0087, C = 10.3199 \) for gaseous CO\(_2\) solute.

### 6.2.5. Formation Rock and Aquifer Salinity Composition

Tables 6.2 and 6.3 list the initial compositions that exist in the formation rock and aquifer. The majority of the rock in the target zone is composed of quartz. In the aquifer water, the highest concentrations are found for sodium, chloride, and potassium ions.
Table 6.2: Initial composition of FQSF rock (from operator).

<table>
<thead>
<tr>
<th>Minerals in Formation Rock</th>
<th>Volume%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>82</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>10</td>
</tr>
<tr>
<td>Debris (not reacted)</td>
<td>8</td>
</tr>
<tr>
<td>Calcite</td>
<td>0</td>
</tr>
<tr>
<td>Dolomite</td>
<td>0</td>
</tr>
<tr>
<td>Dawsonite</td>
<td>0</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>0</td>
</tr>
<tr>
<td>Magnesite</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 6.3: Initial composition of aquifer water (from operator).

<table>
<thead>
<tr>
<th>Ions in the Aquifer</th>
<th>Concentration (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>K⁺</td>
<td>1,455</td>
</tr>
<tr>
<td>Na⁺</td>
<td>12,807</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>494</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>214</td>
</tr>
<tr>
<td>Fe²⁺</td>
<td>0.31</td>
</tr>
<tr>
<td>Fe³⁺</td>
<td>0.65</td>
</tr>
<tr>
<td>Al³⁺</td>
<td>1.07</td>
</tr>
<tr>
<td>Ba²⁺</td>
<td>1.39</td>
</tr>
<tr>
<td>Cl⁻</td>
<td>22,163</td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>289</td>
</tr>
<tr>
<td>HCO₃⁻</td>
<td>338</td>
</tr>
<tr>
<td>CO₃²⁻</td>
<td>0.0</td>
</tr>
<tr>
<td>SiO₂</td>
<td>35.7</td>
</tr>
<tr>
<td>Salinity</td>
<td>37,806</td>
</tr>
<tr>
<td>CO₂ (aq.)</td>
<td>30.30</td>
</tr>
<tr>
<td>pH</td>
<td>6.99</td>
</tr>
</tbody>
</table>
6.2.6. Reactions

The reactions used in this model are listed as follows.

Reactions in aquifer aqueous phase:

\[ \text{H}_2\text{O} + \text{CO}_2^{\text{aq.}} \rightarrow \text{H}_2\text{CO}_3\text{ (carbonic acid)} \leftrightarrow \text{HCO}_3^- + \text{H}^+ \]

\[ \text{OH}^- + \text{H}^+ \leftrightarrow \text{H}_2\text{O} \]

\[ \text{CO}_3^{2-} + \text{H}^+ \leftrightarrow \text{HCO}_3^- \]

Mineral reactions:

Calcite \quad \text{CaCO}_3 + \text{H}^+ \leftrightarrow \text{HCO}_3^- + \text{Ca}^{2+} \]

Dolomite \quad \text{CaMg(CO}_3\text{)_2} + 2 \text{H}^+ \leftrightarrow 2 \text{HCO}_3^- + \text{Mg}^{2+} + \text{Ca}^{2+} \]

Dawsonite \quad \text{NaAlCO}_3\text{(OH)}_2 + 3 \text{H}^+ \leftrightarrow \text{HCO}_3^- + \text{Al}^{3+} + \text{Na}^+ + 2 \text{H}_2\text{O} \]

Kaolinite \quad \text{Al}_2\text{Si}_2\text{O}_5\text{(OH)}_4 + 6 \text{H}^+ \leftrightarrow 2 \text{SiO}_2 + 2 \text{Al}^{3+} + 5 \text{H}_2\text{O} \]

K-feldspar \quad \text{KAISi}_3\text{O}_8 + 4 \text{H}^+ \leftrightarrow 3 \text{SiO}_2 + 3 \text{Al}^{3+} + \text{K}^+ + 2 \text{H}_2\text{O} \]

Magnesite \quad \text{MgCO}_3 + \text{H}^+ \leftrightarrow \text{HCO}_3^- + \text{Mg}^{2+} \]

The mineral reaction rate (whether dissolution or precipitation) is dictated by the composition and pH as the mineral reaction rate model (Bethke, 1996; CMG, 2022) given by:

\[ r_j = \hat{A}_j k_j \left(1 - \frac{Q_j}{K_{\text{eq},j}}\right), \quad j = 1, \ldots, R_{mn} \tag{6.12} \]
where \( r_j \) is the reaction rate, \( \hat{A}_j \) is the reactive surface area for mineral \( j \), \( k_j \) is the rate constant of mineral \( j \), \( K_{eq,j} \) is the chemical equilibrium constant for mineral reaction \( j \) and \( Q_j \) is the activity product of mineral reaction \( j \). The activity product \( Q_j \) is analogous to the activity product for aqueous chemical equilibrium reactions equation as \( Q_j = \prod_{l=1}^{n_{aq}} a_i^v_{i,j} \) (where \( a_i \) is activity of component \( i \) and \( v_{i,j} \) is the stoichiometry coefficient). The product does not involve the activities of the minerals as they are equal to unity.

Solid precipitation occurs when the saturation index \( \frac{Q_j}{K_{eq,j}} \) is larger than 1, otherwise dissolution happens. The reactant reactive surface area, activation energies/equilibrium constants, and reaction rate, obtained from the Wolery database (CMG, 2022), is listed in Table 6.4.

**Table 6.4: Mineral reaction status.**

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Reactive Surface Area (m²/m³)</th>
<th>Activation Energy (J/mol)</th>
<th>( \log_{10} ) of Reaction Rate (1/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>2,709.95</td>
<td>23500</td>
<td>-5.81</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2,864.96</td>
<td>52200</td>
<td>-7.53</td>
</tr>
<tr>
<td>Dawsonite</td>
<td>100</td>
<td>41870</td>
<td>-8.8</td>
</tr>
<tr>
<td>(Equilibrium)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kaolinite</td>
<td>2,594.05</td>
<td>22200</td>
<td>-13.1798</td>
</tr>
<tr>
<td>(Equilibrium)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>K-feldspar</td>
<td>100</td>
<td>41870</td>
<td>-8.8</td>
</tr>
<tr>
<td>(Equilibrium)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magnesite</td>
<td>3,009.29</td>
<td>23500</td>
<td>-9.34</td>
</tr>
<tr>
<td>Quartz</td>
<td>2,650</td>
<td>90,900</td>
<td>-13.4</td>
</tr>
</tbody>
</table>

### 6.2.7. Operating Conditions
According to the operator of the FQSF, a total amount of 1.46 Mt CO\(_2\) will be injected into these saline formations by 2026 (Li, 2022). Four cases are evaluated in this study, listed in Table 6.5, with two well arrangements, displayed in Figure 6.4. In Case 1, gas injection rate is set equal to 0.5344 million Sm\(^3\)/day with 4 years operation with 94.79% mole fraction carbon dioxide (the remainder is methane). This is equal to 0.3648 Mt CO\(_2\) injected annually (total 1.46 Mt CO\(_2\) after 4 years of injection). Here, the start year of carbon dioxide injection will be set to the beginning of 2023 with an end date of injection in the late date of 2026 (4 years after start of injection). The end of 2050 (28 years after start of injection) is a focal point for the operation due to China’s commitment in the Paris Agreement (2015) and an industry carbon neutral target. The simulation will be carried on until 500 years for examining mineral dynamics and longer term fate of the injected CO\(_2\). Cases 2 and 3 extend the injection time to 10 years and 28 years, respectively. Case 4 examines the situation where an additional well is placed in the aquifer with injection time equal to 28 years; in this case, the injection rate in each well is equal to 0.5344 million Sm\(^3\)/day.

**Table 6.5: Simulation cases.**

<table>
<thead>
<tr>
<th>Case</th>
<th>Duration of Injection Interval, years</th>
<th>Well Arrangement</th>
<th>Total Injection Rate, Sm(^3)/day</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4</td>
<td>One well</td>
<td>534,400</td>
</tr>
<tr>
<td>2</td>
<td>10</td>
<td>One well</td>
<td>534,400</td>
</tr>
<tr>
<td>3</td>
<td>27</td>
<td>One well</td>
<td>534,400</td>
</tr>
<tr>
<td>4</td>
<td>27</td>
<td>Two wells</td>
<td>1,068,800</td>
</tr>
</tbody>
</table>
6.3. Results and Discussion

6.3.1. Case 1: CO$_2$ sequestration performance

Figure 6.5 displays the cumulative amount of injected CO$_2$ and change of the amount of supercritical CO$_2$ and dissolved CO$_2$ in the target formation over 500 years. The profiles reveal that during the injection stage (the first 4 years), the supercritical CO$_2$ mass rises but shortly after injection stops, the CO$_2$ rapidly dissolves into the aquifer water. Thereafter, CO$_2$ dissolution slows and evolves to a nearly linear increasing trend with time. The early dissolution rate during injection is associated with the convective transport of CO$_2$ into the formation which raises the interfacial contact area between the injected gas phase and the aqueous phase thus accelerating the dissolution of the CO$_2$. After injection stops, since no more convective growth of the gas
plume, diffusive transport of the CO$_2$ from the region surrounding the supercritical plume dominates. Also, at this stage, the interfacial area no longer grows and the concentration of the dissolved CO$_2$ in the aquifer water surrounding the CO$_2$ plume has been raised which both further limit mass transport of CO$_2$ further into the aquifer. This results in the near linear profiles in Figure 6.5 exhibited after Year 20. The rate of change of the amount of supercritical CO$_2$ in the aquifer is directly related to the rate of dissolution of the CO$_2$ from the gas plume. By the end of injection, ~740,081,000 Sm$^3$ of CO$_2$ (~1.46 Mt CO$_2$) is injected in the formation.

![Figure 6.5: Cumulative amounts of CO$_2$ injected into the target formation, supercritical CO$_2$ (in the gas phase), and dissolved CO$_2$ (in the aqueous phase).](image-url)
Figure 6.6 shows the supercritical CO$_2$ saturation (the fraction of the pore space occupied by SCCO$_2$) at the top of the FQSF. During the injection period, the results show that the CO$_2$ plume spreads outwards from the injection well but due to the nearby boundary, it is forced mainly in the southeast direction. The main transport mode for the plume is by convection associated with the supercritical CO$_2$ flowing into the formation and displacing water away from the well region outwards into the aquifer. This water eventually is forced out through the bottom aquifer at the base of the system. After injection stops, the plume experiences both buoyancy-driven flow extending it outwards mainly within the topmost layer of the formation as well as diffusion which is associated with the movement of CO$_2$ within the supercritical plume associated with the concentration distribution which is directly linked to the pressure distribution within the plume (highest pressure at the well has highest concentration and lowest at the plume edge). Soon after injection stops, the system achieves pressure uniformity and this mode of transport within the supercritical gas phase stops. After 28 years, the buoyancy-driven spreading of the gas phase is evident since the gas is migrating up the anticline but due to the variation of the porosity and horizontal and vertical permeabilities, the movement up to the top of the anticline is not uniform. The formation top topology leads to the splitting of the gas plume into two separate zones at the well as seen at 28 years. After 250 years, the CO$_2$ has been continuously dissolving into the aqueous phase and thus the original CO$_2$ plume has separated into smaller isolated gas zones associated with the structure of the aquifer. At 500 years, the CO$_2$ gas zones has decreased in size due to further dissolution into the aqueous phase.
Figure 6.6: Case 1 – supercritical CO$_2$ gas saturation in top layer of FQSF.
As shown by the aqueous phase reactions in Subsection 6.2.6, CO₂ dissolution into the aqueous phase leads to the production of hydrogen ions, H⁺, and bicarbonate ions, HCO₃⁻. This results in acidification of the water and a reduction of the pH of the aqueous phase. Figure 6.7 displays the evolution of the distributions of pH in the topmost layer of the formation. The evolution of the pH distribution corresponds to the evolution of the supercritical CO₂ plume within the aquifer. Initially, the aquifer water has a pH of 6.99. After the CO₂ dissolves within the aquifer, it forms carbonic acid which dissociates into the hydrogen and bicarbonate ions, lowering the pH to about 4 in the water within the CO₂ plume, as shown in Figure 6.7. After injection stops, due to the buoyancy-driven movement of the CO₂ plume within the system, the pH distribution evolves further within the aquifer. After 250 years, the pH has risen to about 5 in the CO₂ plume region. Profiles of the pH variation with time at the injection well and at locations 450 m and 900 m east of the injection well are displayed in Figure 6.8. The profiles show that when the supercritical CO₂ plume reaches the location, the pH drops to about 4 but after CO₂ injection stops, with time, the profiles rise to between 4.8 and 5.2. This rise of the pH after injection stops is due to mineral reactions and the flow of aquifer water (at its original pH) into the CO₂ plume region (as the CO₂ dissolves into the water and the gas phase saturation drops, water from outside the plume replaces this volume). Given the initial mineral content of the aquifer (mainly quartz and K-feldspar listed in Table 6.2), initial content of ion species dissolved in the water (listed in Table 6.3), and the mineralization reactions listed in Subsection 6.2.6, the acidification of the aquifer water causes the dissolution of the alkaline silicate mineral K-feldspar, as shown in Figure 6.9. This, in turn, yields SiO₂ (quartz) which is deposited within the reservoir.
After 2 years of injection

After 4 years of injection (end of injection)

28 years (end of 2050)

250 years

500 years

Figure 6.7: Case 1 – pH distribution at the top of the FQSF versus time.
Figure 6.8: Case 1 – evolution of pH at the injection well and 450 and 900 m east of the injection well. Inset plot displays evolution over the first 5 years.

Figure 6.9: Case 1 – change of K-feldspar and quartz in entire formation versus time (positive is precipitation and negative is dissolution).
As stated above, the addition of dissolved CO$_2$ causes the generation of both hydrogen ions, H$^+$, and bicarbonate ions, HCO$_3^\cdot$. An interesting dynamic behaviour occurs at the supercritical plume leading edge where the formation of the bicarbonate ions reacts with the native Ca$^{2+}$ and Mg$^{2+}$ ions in the aquifer water to yield precipitated calcite, dolomite, and magnesite. The precipitated calcite distributions versus time in the topmost layer of the formation are shown in Figure 6.10. The results show that the behaviour is dynamic – it forms at a CO$_2$ plume front location but is then consumed after the plume passes beyond that location. The calcite precipitation zone is at the intersection between the CO$_2$ plume front and the non-acidified zone just upstream of the plume. Figure 6.11 displays the total amount of calcite, magnesite, dolomite, dawsonite, and kaolinite formed accumulated in the aquifer through time. Even though the amounts of these minerals formed are small, the amounts of magnesite, dawsonite, and kaolinite are relatively very small throughout time. Since these minerals are continuously precipitated just ahead of the plume front and then dissolved when the acidic plume moves beyond, the total amount of precipitates generated is small. Furthermore, the peak amounts are found just at the end of CO$_2$ injection – thereafter, the amounts of these minerals drops with time.
After 2 years of injection

After 4 years of injection (end of injection)

28 years (end of 2050)

250 years

500 years

Figure 6.10: Case 1 – calcite (kg/m³) mineralization at the top of the FQSF versus time.
Figure 6.11: Case 1 – minerals mass change (precipitation) of minerals.

Figure 6.12 presents the evolution of the average porosity of the entire aquifer through time. When CO$_2$ injection occurs, the porosity rises to a maximum value at the end of injection after which it slightly declines. It is important to note that the average overall porosity of the aquifer changes little (in absolute porosity units, about 0.0035 units) over the entire period of time. The porosity has a net increase during the injection period due to the expanding acidic region where K-feldspar is dissolved, quartz is formed, and calcite and dolomite is formed. After the acidified region stops expanding, due to dissolution of the K-feldspar and declining net precipitation of the calcite and dolomite, the porosity very slightly declines.
Figure 6.12: Case 1 – porosity change versus time.

Figure 6.13 shows a cross-section of the aquifer that intersects the injection well showing the supercritical CO$_2$ saturation. The results show that the CO$_2$ plume remained primarily in the topmost layer of the aquifer – this is due to buoyancy. The CO$_2$ plume spreads in the aquifer along its structure: after injection stops at 4 years, the CO$_2$ plume moves upslope to the anticline (shown at 28 years) leading to a small induced gas cap as seen at 250 and 500 years.

It is clear that the aquifer pore space is not fully utilized and that a far greater amount of CO$_2$ could be stored within the aquifer. The aquifer has a total pore volume space of $\sim 1.455 \times 10^8$ m$^3$ which equal to a CO$_2$ storage capacity about $2.0187 \times 10^{10}$ Sm$^3$ if stored at supercritical conditions. In Case 1 (the design basis for the CO$_2$ sequestration pilot being conducted in the South China Sea), the cumulative CO$_2$ injected is 740,088,000 m$^3$: Given the pore space, about
27 times more CO$_2$ could be stored in the pore space. In the following subsections, a greater amount of CO$_2$ injection is examined.

Figure 6.13: Cross-section of formation about CO$_2$ saturation at black line location vs. time (vertical scale exaggerated by a factor of 5) (blue zones are underburden and overburden).

6.3.2. Cases 2, 3, and 4

Cases 2 and 3 extend the injection period to 10 years and 28 years (until end of 2050), respectively. Case 4 not only extends the injection time to 28 years (until end of 2050) but has an additional injection well is placed in the anticline east of the injection well, shown in Figure 6.4.
The injection rates for each case is listed in Table 6.5. Figure 6.14 displays profiles of the total cumulative CO₂ injected in Cases 1 to 4.

![Cumulative CO₂ injected into the target formation for Cases 1 to 4.](image)

**Figure 6.14: Cumulative CO₂ injected into the target formation for Cases 1 to 4.**

Figure 6.15 displays the evolution of the CO₂ saturation plume in the topmost layer within the aquifer for Cases 2 and 3. Early in the injection process, the CO₂ plumes grow radially into the aquifer due to convection of the gas but due to heterogeneity and the structure of the top of the aquifer, asymmetry develops. For Case 2, after injection stops, the CO₂ plume spreads further due to buoyancy forces and then due to dissolution of the gas into the aquifer water, the plume separates into isolated gas zones that are most pronounced in the anticlines. In Case 3, the plume continues to spread during injection but after it stops, dissolution and buoyancy driven flow isolates large gas caps under the anticlines.
Case 2

4 Years

10 Years (End of Injection)

20 Years

28 Years

Case 3

4 Years

10 Years

20 Years

28 Years (End of Injection)
Figure 6.15: Cases 2 and 3 – evolution of supercritical CO₂ (gas saturation) distribution in the topmost layer of the FQSF (green nodes are injection well location).

In Case 4, the CO₂ saturation plumes arising from each of the injection wells grow and merge after about 12 years (Figure 6.16). After the end of injection, the CO₂ gas plume spreads further in the topmost layer under the action of buoyancy in the aquifer as seen at 250 and 500 years.
Figure 6.16: Case 4 – evolution of supercritical CO₂ (gas saturation) distribution in the topmost layer of the FQSF (green nodes are injection well location).
Figure 6.17 presents cross-sections of the aquifer intersecting the injection well in the east-west direction. The results show that in both cases, the injected supercritical CO₂ collects at the top of the formation and spreads under the action of convection and buoyancy during the injection period and then under buoyancy after the injection period stops. The CO₂ plume evolves according to the structure of the aquifer where it accumulates in the anticline forming a gas cap there but due to dissolution, the CO₂ gas saturated zone diminishes in size with time. The results reveal that even with the greater injection time, the CO₂ gas saturation is primarily in the topmost layer of the aquifer. This implies that still, there is a large volume that is available for storage.

Figure 6.18 displays cross-sections of the aquifer presenting the evolution of the CO₂ gas saturation within the aquifer for Case 4. The results show that a CO₂ plume collects under each well and spreads laterally due to convection and buoyancy during injection. After the end of injection, the CO₂ plume shrinks in size due to dissolution in the aquifer water but there remains a laterally continuous gas layer at the top of the aquifer after 500 years.
Figure 6.17: Cases 2 and 3 – cross-section of formation illustrating evolution of CO₂ gas saturation (vertical scale exaggerated by a factor of 5, blue zones are underburden and overburden).
Figure 6.18: Case 4 – cross-section of formation illustrating evolution of CO₂ gas saturation (vertical scale exaggerated by a factor of 5, blue zones are underburden and overburden).

6.4. Conclusions

In this study, we examine the potential for CO₂ injection and storage in a feldspar-quartz sandstone formation. Given the initial conditions of the minerals in the formation, the dissolved ions in the aquifer water, and the pH, when supercritical CO₂ injection occurs into the formation, there is no mineral formation that would block and damage the aquifer nor opportunities for
mineral precipitation in the injection well. The assessment of the process demonstrates that the trapping mechanisms are solubility and structural trapping. Due to the acidification of the aquifer water, the K-feldspar in the formation is dissolved with formation of a small amount of silica. An interesting dynamic behaviour occurs where slightly ahead of the CO$_2$ plume, divalent cations in the aquifer water react with bicarbonate to form carbonates but as the acidified region associated with the CO$_2$ plume passes these zones, it is re-dissolved. For the operation of this CO$_2$ sequestration pilot, no wellbore blockage is a key benefit for the operation. The results demonstrate that the system could be used to store CO$_2$. 
CHAPTER 7: Conclusions and Recommendations

7.1. Conclusions

The following conclusions are made from the data used in the research documented in this thesis. The overall conclusions that from the research are listed as follows:

1. The results demonstrate that both hydraulically fracturing-EGS and non-fractured systems at BCSU are capable of realizing greater energy produced than energy invested. The results show that the energy produced versus energy invest ratio tends to be greater than 5 for most of the operations considered here. However, the benefit of hydraulic fracturing mainly contributes to greater production of energy due to easier flow within the reservoir enabling higher production rates especially in the early stages of the process.

2. The results show that hydraulic fracturing acts to accelerate geothermal energy production but eventually the performance is similar to that of the non-hydraulically fractured cases. But it also bring into question whether hydraulic fracturing of geothermal systems will help and whether they would provide economic benefits given the costs of hydraulic fracturing stimulation.

3. The results show that CO₂-EGS at BCSU can produce energy but the power recovered is not sufficient to operate the CO₂ compression system. After CO₂ breakthrough occurs, the total amount of geothermal heat recovered is 49,835 MWh and the net amount of CO₂ stored in the geothermal reservoir is 6.3 Mt (taking the CO₂ generated from the compression operation into account). If the produced water is co-injected with the CO₂, its effect on the system is small and the energy recovered is essentially the same as the CO₂-only case.
4. The results show that CO$_2$-EGR in the Yinggehai Basin enhances the amount of methane produced from the reservoir. The amount depends on the placement of the injection and production well and the number of injection well. The CO$_2$ plumes are shown to evolve in the reservoir until they encounter each other or the fault system or the production well. The incremental recovery of methane is between 23 and 127%.

5. The results also reveal that the CO$_2$-EGR in the Yinggehai Basin opens the door to potentially carbon negative natural gas with respect to the consumption of the natural gas as fuel (the total life cycle has not yet been assessed).

6. The results show in the FQSF CO$_2$ offshore sequestration project that majority gaseous CO$_2$ present under super-critical condition with structural and residual trapping; parts of CO$_2$ continuously dissolve into aquifer fulfill the solubility trapping; and outside of acidic zone, a small amount of mineral trapping of carbonate precipitation is also detected under a slow speed.

7. The results show in the FQSF CO$_2$ offshore sequestration project that CO$_2$ dissolving is capable generating an acidic region for preventing carbonate precipitation to block the wellbore on solubility trapping aspect. The aquifer and formation rock composition have a highly impact on the mineral precipitation in mineral trapping. The alkaline silicate mineral in formation will decide either there will be a mineral precipitation or not. The cation ion in aquifer will decide what kind of carbonate mineral is precipitated. And the cation ion recharge will decide how many carbonate minerals will be precipitated.

8. The results show in the FQSF CO$_2$ offshore sequestration project that the operation of increasing total injection amount of CO$_2$ is possible for this reservoir.
7.2 Recommendations

1. The results suggest re-fracturing the reservoir at some later point of time to potentially further enhance geothermal heat recovery on hydraulically fracturing–EGS project at BCSU. The results suggest stopping geothermal heat harvesting for a period of time to allow the natural geothermal heat flux to replenish the reservoir.

2. The results suggest that combined CO\textsubscript{2} sequestration and geothermal heat recovery systems at BCSU should be examined where CO\textsubscript{2} sequestration operations are planned in mobile water geothermal reservoirs.

3. The results suggest that three injectors with triangle placement around the production well is better than two injectors with linear placement and less injectors should be placed at other side of the faults for the Yinggehai Basin CO\textsubscript{2}-EGR project.

4. The results suggest increasing injection time or injector to store more CO\textsubscript{2} into the formation for FQSF CO\textsubscript{2} offshore sequestration project.
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